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PREFACE

KEY RECOMMENDATION

The terms of reference provided a logical sequence for the Inquiry to assess the future baseload electricity generation requirements of New South Wales, and the most efficient means for ensuring that the required investment funds would be forthcoming at the appropriate time. On the basis of submissions made to the Inquiry, together with expert consultant reports, I have determined that there is a need to be prepared for additional investment in baseload from 2013-14. Further, the most efficient means of providing for baseload is to improve the commercial and policy signals used by the private sector when investing in generation capacity in New South Wales. My key recommendation, therefore, is that the Government of New South Wales divests itself of all State ownership in both retail and generation. The process leading to this recommendation is outlined below, and covered in depth in the main body of this report.

Background

A **baseload** power plant is one that provides a steady flow of power regardless of total power demand by the grid. These plants are designed to run continuously throughout the year except in the case of repairs or scheduled maintenance, and provide the bulk of the electricity needs of New South Wales. Baseload plant can usually only operate within an output band and can take a significant amount of time to start up. In New South Wales, at this time, baseload power plants use coal as fuel. Fluctuations, peaks, or spikes in customer power demand are handled by smaller and more responsive types of power plants.

Over recent years the nature of baseload has changed. Peaks in electricity demand have been accentuated, particularly in summer, and this trend is expected to continue. Thus there has been a requirement for additional "peaking" capacity, largely to provide for changing commercial and residential usage patterns in New South Wales, rather than baseload. In addition, electricity produced from some "renewable" technologies enters and leaves the system in significant quantities, but intermittently, essentially substituting for baseload. To overcome the intermittency, therefore, flexible back-up plant is required. This is likely to become more of an issue for New South Wales as additional renewable energy enters the system, driven by Government programs and policies designed to encourage investment in renewable technologies.

Hydro and open cycle gas turbines (OCGTs) are the main providers of peak supply in New South Wales. Gas can also be used as a baseload fuel in combined cycle gas turbine (CCGT) plants. The modular nature, lower capital cost, and lower carbon dioxide (CO_2) emissions of CCGT plant is increasingly viewed as a more flexible and environmentally sensitive option to coal-fired plant for baseload. However, uncertainties regarding the price of carbon and the availability and price of gas combine to make a choice between coal and gas for the next baseload station a very complex issue.

The National Electricity Market

The National Electricity Market (NEM) was established in 1998 to provide a competitive wholesale market for the supply of electricity in New South Wales, Queensland, South Australia, Victoria, the Australian Capital Territory and, in 2005, Tasmania. Prior to the NEM, these States all had centrally planned electricity supply which were often characterised by over-investment in generating capacity due to the lack of market-based price signals. As a result, capital expenditure was allocated in a sub-optimal manner, effectively at a real cost to taxpayers and electricity consumers. The subsequent deregulation, or liberalisation, of electricity markets was not unique to Australia, and many other market-based economies were implementing their own competitive models during the 1990s.

The NEM is a compulsory gross pool market. Generators bid to supply the market with specific amounts of electricity at fixed offer prices for half-hour periods throughout the day. During dispatch, prices are calculated at five minute intervals and then averaged over the half-hour trading interval for settlement purposes. There is a price cap of $10,000 per megawatt hour, and a price floor of negative $1,000. Retailers purchase in the pool market, but the eventual price paid by them will depend on what hedging contracts that they have in place to give them their desired degree of price stability. Various market regulations exist to ensure security and reliability in the NEM.

The NEM permits electricity to be traded over State borders, subject to physical transmission constraints. Queensland transmits considerable quantities of baseload power to the NSW market. New South Wales and Victoria draw power from the Snowy Mountains Hydro-electric Scheme. Whilst it would be possible for any future increase in NSW baseload requirements to be met with additional imports, the ongoing transportation of electrical energy over long distances results in significant energy losses, and development of interstate generation in support of NSW load is only financially sensible where there are substantial differences in fuel costs. Considering NSW prospective coal seam methane resources and large coal reserves, there is a strong likelihood that NSW generators will be able to obtain fuel at least similar or even lower costs than generators in other jurisdictions, leading to increased NSW generation and reduced interstate energy flows in the medium term.

Does NSW need new baseload supply and when does it need it?

New South Wales continues to experience a declining rate of growth of electricity consumption. For the next decade, growth is projected to average 1.8 per cent per annum as compared with 2.5 per cent per annum over the past decade. This has been largely due to the impact of energy efficiency improvements and the public's growing awareness of environmental impacts, both of which are expected to continue. However, despite expected lower rates of growth in future electricity demand, electricity supply and demand forecasts indicate that the State needs to be prepared for additional baseload power supply by 2013-14.

Some submissions to the Inquiry have argued that the need for new baseload supply will occur later than 2013-14. They have asserted that enhanced levels of energy efficiency, higher levels of supply from existing generators, renewable technologies, and additional sources of distributed power suggest that this date can be extended significantly into the future. Other submissions have contended that only peaking and intermediate plant is required over this timeframe.

There is no doubt that the effects of a range of NSW Government measures for mitigating environmental degradation, and specifically climate change, has produced significantly enhanced levels of energy efficiency in New South Wales. Whilst these measures are analysed in depth in the main body of this report, it is worth noting that the NSW Greenhouse Gas Reduction Scheme, a forerunner of the proposed national emission trading schemes and one of the first mandatory greenhouse gas emissions trading schemes in the world, has been a major factor in making CCGT technology competitive with coal in New South Wales through the issue of NSW Greenhouse Gas Abatement Certificates (NGACs).

On balance, I have decided to recommend a risk-averse approach and focus on the 2013-14 timeline. Depending on the technology, the lead-time for planning and building a new baseload power plant ranges from five to seven years, so the process has to begin now. The cost to the State of not being prepared in time is large relative to the cost of investing, with hindsight, a little earlier than may have been required. Further, being prepared today does not prevent delay in the future if the time horizon for additional baseload requirements moves outwards, possibly due to those factors outlined in the above paragraphs. However, it should be noted that current demand management and energy efficiency initiatives are already factored into the forecast of NSW electricity consumption, so it must be new initiatives (such as carbon trading and changes in current consumption patterns) that will alter the picture.

Is it essential that the NSW Government fund the new supply?

Ultimately the electricity consumer pays for the new supply through electricity prices. In turn, price levels will be determined by both the competitive structure of the market and the efficiency of investment decisions of the generators.

Historically, the Government has ensured the State's security of generation supply through ownership of, and investment in, power stations, but the establishment of the national energy market during the 1990s has created a competitive market structure that forces commercial disciplines on investment decisions in new generation capacity.

In current day dollars, the cost of new investment in generation capacity in New South Wales over the next 10 to 15 years is expected to be in the vicinity of $7 billion to $8 billion. The rather wide range reflects a number of market uncertainties, including the timing and quantum of the investment decision, which itself is determined by rates of growth of demand, new sources of large loads, and recent significant price increases for power station components.

In regard to just the required investment in new generation, approximately half could be funded by the State-owned generators, with the balance coming from the Government through either increased borrowing, higher taxes or reprioritising other Government expenditure programs. However, additional debt funding, particularly for investment in assets that rely on market-determined revenues, may have an adverse impact on the State's AAA credit rating. Given the importance of New South Wales maintaining its AAA credit rating, such an outcome is undesirable, whilst the latter two options are unnecessary. This issue is discussed in depth in the Report.

Given these consequences, I have focused on two key issues: (i) how much would the Government need to invest and fund in total in the State's electricity industry, and (ii) is it appropriate that the Government fund this investment.

On the first point, Government investment in new generation capacity will mark the continued involvement of Government in the State's now competitive electricity retail and generation markets. Rightly or wrongly, due to the market perception it creates, Government participation in these competitive markets is either 'all in' or 'all out'. The current arrangement in New South Wales will ultimately lead to Government funding nearly all, if not all, investment in the State's electricity industry over the next 10 to 15 years.

The total investment necessary for Government to remain an active and successful participant in this industry, however, is not limited to the capital cost of new generation plant. The Inquiry found strong evidence that the State-owned retail businesses will struggle to remain viable without significant additional capital to adjust their business model to suit the competitive environment in which they operate. The capital cost of ensuring their competitive viability is in the range of $2 billion to $3 billion.

As well, the impending carbon price may necessitate additional future investment in carbon reduction technologies. This could involve funding of about $3 billion to $4 billion to retro-fit some existing power stations over the next 10 to 15 years.

In total, future industry participants could expect to fund some $12 billion to $15 billion worth of investment in order to ensure compliance with regulatory requirements and commercial competitiveness. The question for Government is whether this is a sensible investment for it to undertake given competing demands for Government funds and the opportunity cost in terms of other Government activities that this investment would entail.

This investment would be additional to Government investment in the State's electricity transmission and distribution networks, which alone is estimated to be around $10 billion over the next four years.

While I recognise this investment, or at least most of it, should earn a rate of return, it is the Government's preference that if it is not essential for Government to fund this investment then it does not do so.

On the second point, as explained in depth in the Report, I conclude that Government funding, in place of private sector funding, is not essential to allow Government to ensure security of supply or achieve appropriate price, social or environmental outcomes from the State's electricity industry.

What are the realistic technological options to deliver new baseload by 2013-14?

The most technologically advanced, commercially viable options currently available for the next tranche of baseload generation in New South Wales are CCGT and Ultra-supercritical Coal (USC). A CCGT plant has lower capital costs than USC technology, a shorter construction period, and about half the level of CO_2 emissions per unit of power generated. However the relative fuel cost advantage of coal over gas has, in the past, given coal a distinct commercial advantage for system baseload.

Given the lower carbon emissions footprint of gas, a carbon price could reverse this outcome provided the degree of fuel switching stimulated by the carbon price did not offset this advantage by way of higher gas prices. Depending on the carbon price signal, and government policies and support, the technology for subsequent investment cycles of baseload power plants may involve low carbon emissions technologies, such as carbon capture and storage. Depending on relative fuel prices at that time, these technologies may alter the relative costs of gas and coal-fired technologies again.

Emerging baseload technologies, such as geothermal and solar thermal will not be commercially available by the time new baseload is predicted to be required, but clearly have potential for future additions to baseload, particularly in a carbon constrained environment.

Carbon capture and storage (CCS) is viewed as the major enabling technology to counteract climate change. Coal is in plentiful supply, has minimum problems with energy security for most countries, and is relatively cheap. Although capture technologies have been used since the 1970s for CO_2 capture in other industries, applications on the scale of baseload power stations are only just entering the pilot stage.

Currently costs are very high and there is a corresponding lack of practical experience regarding its technical feasibility, particularly with regard to underground storage of the gas. Whilst CCS is unlikely to be commercially viable for the next tranche of baseload plant in New South Wales, such plant could be made "carbon capture ready" and potential CO_2 reservoirs could be identified in order to retrofit when the market determines it to be appropriate.

Nuclear power is a viable enabling technology but, despite its relatively good history on safety, has environmental and nuclear proliferation issues that would invariably cause long development delays due to public and political scrutiny in Australia. In addition, the regulatory environment for enabling Australia to become self-sufficient at all stages of the nuclear fuel cycle does not currently exist. Nuclear power would also require a significant carbon price in order to compete with coal or gas for baseload. It should be noted, however, that in his speech to the NSW Parliament on 9 May 2007, the Premier, the Hon. Morris Iemma, MP stated 'there will be no consideration of nuclear energy for NSW whatsoever'.

Ultimately the choice of the appropriate technology, both current and prospective, is an investment decision that private sector businesses must address on a purely commercial basis. Utilising plant components or designs which are unproven, or have demonstrated poor reliability, or are at an early stage of development pose an unacceptable risk, given the high reliability requirements of the electricity supply system. The level of maturity can impact on both system reliability and the ability to finance a project. Providers of finance for power projects are risk-averse and an unproven technology would generally find it difficult to find financial support.

Why is there a lack of private sector investment in generation in NSW?

In comparison with the other mainland States in the NEM, private sector investment in the electricity sector in New South Wales is minimal. The State owns the vast majority of both electricity generation assets, including baseload generation capacity and electricity retail customers. It is also the owner and operator of the State's electricity transmission and distribution networks.

The private sector will invest in generating capacity when wholesale prices and market-related conditions point to a decision based upon commercial criteria. They are investing over long time horizons and therefore need confidence on the efficacy of the market they are entering. The predominance of publicly owned businesses in New South Wales, however, gives rise to a number of factors and uncertainties that inhibit private sector investment in the generation sector. This is particularly the case for additions to baseload, where there is the perception that investment behaviour of State owned generation is not subject to the same capital market disciplines as the private sector.

Investment occurring earlier than warranted by market signals, could give rise to excess capacity and hence a devaluation of generation assets. Since additions to baseload involve large, lumpy investments, the State generators with their portfolios of generating assets could adjust capacity accordingly. However, a financial penalty would be imposed on taxpayers through higher costs resulting from an inefficient investment decision. But a new private generation entrant, without a portfolio of assets, could well be left stranded with costly surplus capacity. Investment in peaking plant is less of a problem, since its modular, smaller nature reduces the size of the investment at risk and gives it a much greater flexibility in responding to changing prices and other market-related conditions.

If the Government is not going to finance and own baseload supply, what needs to be done to ensure that the private sector will build it in a timely manner?

A generator will build new baseload plant to meet anticipated increases in demand and to optimise the value of their portfolio of generation assets. There are a number of commercial incentives, such as “first mover” and owning least cost generation, which will encourage owners of generation to invest in a timely manner in new baseload. Under the realistic assumption that new technology will be more cost-effective than existing technology, both in terms of energy output and emissions of CO_2, a new baseload plant would force, now higher cost, competing baseload plants lower down the merit order. In other words, the new plant would force older plant to reduce output with corresponding adverse impacts on their cash flow.

However, there are a number of commercial and policy issues that are relevant for private sector investment in electricity generation. The following actions are required to address these issues.

1. Uncertainties surrounding the implementation of a national carbon pricing and trading scheme must be minimised.
2. The market structure facilitates the desire of private sector investors for a relatively stable revenue stream, which can be obtained by vertical integration of generators and retailers or investment by portfolio generators which have existing plants.
3. Site access and planning processes should have the greatest degree of transparency and faster processing.
4. The NSW Government should not invest in electricity generation or retailing.

What will happen to electricity prices if generation and retailing are sold to the private sector?

The wholesale electricity market has exhibited relatively high price volatility and, more recently, dramatic increases in prices due to a number of factors, including the prolonged drought which has constrained power production due to a shortage of cooling water at some inland NSW baseload power stations.

Currently the NSW Government mitigates the risk of this volatility flowing through to regulated retail prices through the Electricity Tariff Equalisation Fund (ETEF), but ETEF will be phased out by 2010. Market-based price hedging mechanisms will then be required to replace it. The private sector is increasingly managing this risk through vertical integration (i.e. owning both retail and generation assets). However this would not be an option for New South Wales if the retail sector were privatised whilst generation remained in State ownership. The retailers could hedge through investing in peaking capacity, but the generators would be exposed to downside wholesale price volatility. To minimise the State's exposure to wholesale market risk, therefore, both retail and generation would need to be transferred to the private sector.

It is impossible to anticipate the future direction of electricity prices, particularly as the imposition of a carbon trading regime in Australia is imminent. However, provided a competitive environment exists, then I would anticipate that prices would be lower than they would in a market dominated by Government owned companies. It should be noted, that the effectiveness of competition in New South Wales will be reviewed by the Australian Energy Market Commission in 2009 with the objective of considering whether retail price regulation should be removed.

What impact will a national carbon trading scheme have on baseload investment decisions in the private sector?

It appears inevitable that a carbon emissions 'cap-and-trade' scheme will be operating at a national level in Australia commencing no later than 2012. The intention of introducing such a scheme is to allow the market to determine the least cost method for achieving a designated emissions 'cap'. The level of the cap is determined on the basis of scientific knowledge regarding the damaging impact of carbon emissions on the planet, in combination with the estimated cost of mitigating such impacts. Basically, such a scheme is designed to place a price on carbon which drives changes in consumer purchasing behaviour and producer investment behaviour towards low-carbon technologies. Since the nation's carbon emissions cap would be fixed, total emissions would be restricted to a maximum of the cap but at an emissions trading price which is determined by the market for permits.

The creation of a national emissions trading scheme involves the design of a complex market structure that must encompass all major carbon emitters whilst simultaneously protecting Australia's energy-intensive export industries from competitors not themselves subject to a carbon price regime.

In the context of the electricity sector and current technology options, the price of carbon permits will play a critical role in determining the relative competitiveness of coal and gas-based technologies after the scheme is introduced. Whilst existing generators are likely to receive emissions permits to cover some or all of their emissions based upon historical levels, new investments will need to have permits to cover all of their emissions. Thus future investors in electricity generating plant in New South Wales must factor in the cost of carbon in assessing their commercial viability. With CCGT plants producing approximately half the CO_2 emissions of USC plants, the cost of carbon will be a major element in the choice of investment technology for baseload.

At present, a number of key commercial parameters relating to a national carbon trading scheme are uncertain. Briefly, these are:

- the national emissions targets and associated dates for achieving such targets are vague
- the proposed carbon emissions cap for the electricity sector, and its transition path, are unknown
- the criteria for allocation of free emissions permits to current emitters has not been specified
- the penalty price for non-compliance has not been set.

The high level of emissions market uncertainty tends to favour CCGT technology given its lighter carbon footprint, but other uncertainties surrounding capital and relative fuel costs will also be major determinants of the choice of technology. In addition, it is important to consider both plant and system emissions when assessing the carbon footprint of new baseload investment. For example, to the extent that a new coal-fired baseload power station induces retirement of existing older coal-fired plant, additional output could be achieved with, potentially, a lower net level of carbon emissions per unit of system generation output.

At least in theory, an emissions trading scheme should ensure the required outcome, *viz*: national emissions do not exceed the national cap in the target year(s). In practice, if the cap is very stringent, then complementary measures are likely to be required to ensure that the transition path does not impact unduly on economic activity. For example, a 60 per cent reduction in CO_2 emissions by 2050 (the State's declared target) will require rapid penetration of (non-nuclear) low CO_2 emission technologies that are currently neither technically nor financially viable, which would be a challenging requirement given the 30+ year existence of a power plant built today. The technology options and scenarios for meeting the State target are addressed in the Report.

If gas is the preferred fuel for new baseload, are there sufficient gas supplies available?

There is a requirement for a high degree of certainty that gas supplies and delivery infrastructure will be available to New South Wales, as required, to meet an expected increase in investment in CCGT technology. The market will deliver it if undistorted price signals are evident. There are sufficient gas resources in the Eastern States to support long-term gas-fired generation capacity additions in New South Wales. These are predominantly located in South East Queensland and offshore Victoria (the Gippsland and Otway Basins). In addition, the potential exists for significant (coal seam) gas supply from within New South Wales.

Current NSW gas prices ($3-$4/GJ) reflect the “stranded” nature of the resource in the Eastern States. If there is potential for this resource to be exported as Liquefied Natural Gas (LNG), then the domestic price could be expected to parallel North-West Shelf gas prices (currently around $8/GJ delivered from Western Australia to New South Wales by pipeline or $10-$13/GJ as LNG). Gas supplies from Western Australia and/or the Northern Territory, either by pipeline or LNG, are therefore too expensive on a delivered basis to render CCGT competitive with coal plant in New South Wales. Additional investment in an adequate and reliable NSW gas transmission network will be required to meet rising gas demand.

What is the role of government in investment in infrastructure?

Governments seek to influence infrastructure investment for a number of reasons. First, private markets may not supply some goods where there is no well-defined market for the individual, such as street lighting, so government provision may be necessary. Second, some services may provide benefits to society over and above those that accrue to the individual. These external benefits, or positive externalities, are often cited to justify spending on public education and public health. Finally, the existence of natural monopoly, i.e. when the minimum efficient size of plant is so large relative to market size that the market can support only one supplier (e.g. electricity transmission lines), may also warrant intervention.

Essentially, therefore, government expenditure on infrastructure is an opportunity cost issue. In other words, Government investment on infrastructure that can be adequately provided by the private sector, such as power generation, is at the expense of investment in other infrastructure requirements (e.g. policing, education and transport) that may not attract adequate levels of private investment or may not provide basic levels of service across all communities in New South Wales. Thus government ownership should ensure an adequate level of security of supply of these services. Since electricity generation and retail operate in a competitive market, there is no rationale for Government ownership based upon any inability of the private sector to provide a secure supply at competitive prices.

What options are available to the NSW Government?

Retail Sector

There are currently three State owned retailers in New South Wales: EnergyAustralia, Integral Energy and Country Energy. They compete against each other and against private sector retailers. They combine retailing with maintenance of the distribution network but, unlike their private sector competitors, own only limited generation assets to manage risk and optimise returns. Without major changes to their business models, it is very likely that their customer base will erode as the result of competition from private retailers. In the event that the Government decides not to divest itself of the retail businesses, then additional investment in the range of $2 billion to $3 billion would be required to move the State-owned retailers onto a more equal competitive footing with their private sector competitors.

One option for an investment profile could, comprise of $1 billion to $2 billion to develop an upstream gas position by either acquiring an upstream gas company or by investing in gas exploration, and in excess of $1 billion to develop a portfolio of generation assets (peaking, intermediate and potentially baseload). There would appear to be little value in spending taxpayers' money on transforming the State retailers into viable commercial entities in a competitive market where the private sector can provide the same service unfunded from the public purse. It is, therefore, my recommendation that the value of the retail assets of these three businesses should be realised now with their transfer to the private sector rather than remain State owned.

Transferring the retail businesses by themselves to the private sector, however, will not be sufficient to ensure the likelihood of investment in baseload, although it would encourage timely investment in peaking plant. Retailers focus not on the level of wholesale and retail prices, but the margin between them and ensuring that they have sufficient and timely capacity. Investing in peaking plant gives a retailer a hedge against price volatility, whereas investing in baseload would simply reduce the average wholesale price of electricity across the market, thus benefiting its competitors and new entrants in addition to itself.

Generation Sector

The three State-owned generators, Macquarie Generation, Delta Electricity, and Eraring Energy compete with both public and privately owned generators across the NEM. In the absence of private sector investment in baseload, the NSW Government would be forced to allocate capital to support expansion of one or more of its generators.

Under private ownership of generation, multiple projects might proceed as private sector participants attempt to gain a competitive advantage over each other. In addition, private ownership of current generation assets would enable additions to be made to a portfolio of generation assets, thus reducing the lumpy nature of baseload investment by retiring or winding back old plant. However, under State ownership this could be considered an irresponsible way of investing NSW taxpayers' money if the State-owned generators competed against each other in this manner.

Privatisation of both the electricity retail and generation sectors would offer the opportunity for companies to become vertically integrated (i.e. own both a retail and a generation business) thus allowing them to adopt more cost-efficient outcomes. Whilst vertical integration would also be possible under Government ownership, subject to ACCC agreement this ensures that the State has to finance and build additional baseload power plants and would in all likelihood deter private sector investments in all but peaking plant. Again, there is no rationale for Government to be involved in a competitive market.

Under current market conditions, I consider that the private sector is very unlikely to invest in baseload generation in NSW. On the basis of the evidence gathered in the course of this Inquiry, I conclude that the most efficient way of addressing this problem is for the transfer of both retail and generation assets to the private sector. This would permit market-based electricity prices to send appropriate price signals to encourage the timely take up of investment and to facilitate the benefits of vertical integration of retail and generation for NSW consumers.

In the event that the Government does not wish to sell generation, then appropriately structured long-term leasing of current generation assets should be considered as a viable alternative. The State would retain ownership of the assets, with operational and commercial control by the private sector. A sufficiently long lease would provide an incentive to maintain the commercial life of the asset, and to invest in emission reduction technologies such as CCS. This option would be consistent with the Premier's statement in Parliament on 9 May 2007 that 'there will be no sale of electricity generation, transmission or distribution'.

Again, consistent with the Premier's statement in the previous paragraph, sale of retail and sale or lease of generation would not include the sale of the high-voltage transmission and the low-voltage distribution (the so-called "poles-and-wires" business) networks, which can remain in public ownership without affecting incentives for private sector investment in generation.

In summary: how can timely investment in new generation consistent with the State's AAA credit rating be ensured?

1. Divest the retail arms of EnergyAustralia, Integral Energy, and Country Energy.
2. Divest or lease the State's generation businesses: Macquarie Generation, Delta Electricity, and Eraring Energy, including their development sites.
3. Ensure efficient, timely, and co-ordinated development application and environmental planning processes for generation stations and new resources of fuel, such as coal and coal seam methane projects.
4. Commence the process of obtaining development approval for the development sites of existing generators.
5. The Commonwealth should design a set of guiding principles to reduce some of the uncertainties regarding the impact of the introduction of emissions trading on investment in the electricity generation sector and to facilitate the adoption of ultra low CO_2 emissions technologies. Specifically, as soon as possible it should:
   - Establish the economy-wide greenhouse gas emissions caps and associated time frames
   - Establish the penalty price for non-compliance
   - Announce the criteria upon which emissions permits will be allocated
   - Announce trade – exposed exemptions.

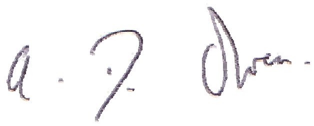
Acknowledgements

This report is the result of input from numerous companies and individuals. The list is too long for me to acknowledge all contributors individually, so I would like simply to thank all those who provided written and verbal submissions to the Inquiry for their interest and the considerable amount of time and resources that were expended in the process. All submissions can be viewed on the Inquiry web site. I read them all.

I would also like to thank those individuals associated with Morgan Stanley, Wood Mackenzie, and Connell Wagner for their excellent reports and on-going advice throughout the Inquiry process.

The Secretariat for this Inquiry was drawn from a number of NSW Government Departments, and the material in the Report was largely contributed by people from the same Departments. I would like to thank the Steering Committee, and Judy O'Connell and the Secretariat team for their valuable contribution and dedication throughout the Inquiry process.

Finally, I would like to thank the Premier of New South Wales, the Hon. Morris Iemma, MP for inviting me to undertake this task.



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1. Overview

1.1 The Inquiry

What are the Terms of Reference?

The NSW Premier, the Honourable Morris Iemma, MP established an Inquiry into Electricity Supply in NSW (the Inquiry) in May 2007 to advise the Government on the actions it needs to take for a timely investment in new baseload generation.[1]

The Inquiry's terms of reference are to:

1. Review the need and timing for new baseload generation that maintains both security of supply and competitively priced electricity.
2. Examine the baseload options available to efficiently meet any emerging generation needs.
3. Review the timing and feasibility of technologies and/or measures available both nationally and internationally that reduce greenhouse gas emissions.
4. Determine the conditions needed to ensure investment in any emerging generation, consistent with maintaining the State's AAA credit rating.

How important is a reliable electricity supply to NSW?

Providing reliable and competitively-priced electricity to the people of New South Wales is an essential service. It allows our businesses to compete domestically and overseas, and support's the quality of life that is enjoyed by across the State.

Maintaining high standards of reliability for both electricity and gas is a key priority for the NSW Government. A reliable electricity supply must be considered from the perspective of both electricity generation, and the transmission and distribution network that delivers electricity to homes and businesses. Network reliability is very high in New South Wales and the Government is pursuing the even more ambitious reliability targets as set out in its the State Plan[2].

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[1] See Appendix 1.1.

[2] NSW Government, State Plan: A new direction for NSW, November 2006.

Over the next four years, NSW transmission and distribution businesses will invest over $10 billion in expanding and upgrading the State's electricity network in Appendix 1.2 gives a snapshot and overview, of the NSW electricity sector, including its different components, and further discusses network reliability.

Generation reliability means that New South Wales needs to generate or import enough electricity to meet customer needs at all times, including times of peak demand. The State's everyday energy needs should be met in a way that gives its customers value for money. Until the beginning of this decade, New South Wales had the capacity to generate much more electricity than it needed. This followed the building of several large generators in the 1980s and early 1990s, and improved plant performance during the 1990s.

In 1998, the National Electricity Market (NEM) began operating as a wholesale market for the supply of electricity to retailers and end-users in New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory[3]. Transmission interconnectors allowed electricity to be sent across jurisdictions. The NEM allows low cost power in those States with spare capacity to flow to States that need more capacity. Ongoing improvements in the NEM's operation, upgrades to existing generators and development of generators designed to run at times of peak demand, have also helped ensure reliability of supply.

Why is there a need for this Inquiry?

The NSW Government has a crucial role in reviewing whether electricity supply will continue to be adequate for the state's current and projected energy needs. This includes assessing whether current supply options will continue to meet energy needs in an economically efficient way. The Government also ensures that policy settings enable the market to come forward with new investment appropriate to emerging needs.

In looking at baseload options, the Inquiry particularly focussed on policy settings that would enable the investment decisions needed to maintain an ongoing secure electricity supply.

Demand catching up with supply

The State's energy consumption has grown consistently over the last 30 years. Energy demand is expected to continue to grow over the next ten years but at a lower rate, due in part to energy efficiency measures. As no baseload generation plant has been built in New South Wales in the last 15 years, the energy consumed in New South Wales is catching up with supply. Chapter 2 discusses these trends in detail.

[3] Tasmania joined the National Electricity Market in 2005.

The advent of new technology with improved characteristics including higher efficiency, lower carbon dioxide (CO_2) emissions and lower water usage, is important in reviewing the need and timing of new investment in generation. This is particularly the case given growing public awareness of the energy sector's contribution to greenhouse gas emissions and expectations that the sector will play a key role in reducing future emissions.

The Inquiry was also asked to advise the Government on whether new investment is generation was needed, and if so, when, and what the options for new generation were.

Public and industry interest in a reliable electricity supply has been heightened by the effect of the drought. The water shortage has reduced the output of some hydro and coal-fired generators (which respectively use water to turn turbines, and for cooling), and has placed upward pressure on wholesale electricity prices.[4]

Environmental and finance issues

The Inquiry's terms of reference reflect the Government's commitment to the environment. In the State Plan, the Government has committed to a 60 per cent reduction in greenhouse gas emissions by 2050 and a return to year 2000 greenhouse gas emissions levels by 2025 (Priority E3). In addition, 15 per cent of electricity consumed in New South Wales is to be from renewable sources by 2020 (Priority E2). Climate change and environment protection policy will therefore have a major bearing on future generation investment options in.

Similarly, the NSW Government's commitment to responsible financial management and the maintaining the State's AAA credit rating (Priority P1) will also have a major bearing on future generation investment options.

How did the Inquiry approach its task?

Invitation for written submissions

The Inquiry has encouraged broad public participation and used an evidence-based approach for its terms of reference. It invited the public and other stakeholders, through newspaper advertisements and its website, to make written submissions.

[4] The impact of the drought on electricity generation in the NEM is being monitored by the Ministerial Council on Energy with the assistance of the National Electricity Market Management Company (NEMMCO). NEMMCO has released a report and update titled "Potential Drought Impact on Electricity Supplies in the NEM", Final Report, 30 April 2007, and "Drought Scenarios Investigation August 2007 update", 2 August 2007, at www.nemmco.com.au.

The Inquiry received 74 written submissions. These came from a range of stakeholders, including members of the public, businesses that use and supply electricity, peak industry groups, unions, environmental groups, community welfare organisations, and Members of Parliament. Professor Anthony Owen also met with many stakeholders to further discuss their views and concerns.

Appendix 1.4 lists the stakeholder submissions and meetings and Appendix 1.3 gives a summary of submissions.[5] The Inquiry is grateful to participants for their extensive and detailed submissions and their involvement in discussions.

Specific research commissioned

The Inquiry also gathered and reviewed other information relevant to its terms of reference. This included publicly available research papers and analyses of electricity supply and demand, discussed throughout this report.

The Inquiry commissioned extra work to supplement existing information in these four key areas:

- Potential baseload generation technologies likely to be available as the next tranche of baseload capacity needed in New South Wales (advice provided by Connell Wagner).
- Potential carbon emission reduction technologies, such as carbon capture and storage (advice provided by Connell Wagner, with assistance from Dr Lila Gurba[6] and peer review from Dr Kelly Thambimuthu[7]).
- Ongoing availability and cost of gas supplies for baseload generation in New South Wales (advice provided by Wood Mackenzie).
- Conditions required for private sector investment in new generation in New South Wales and the options available to bring about those conditions for investment (advice provided by Morgan Stanley).

Reports from Connell Wagner (Expert Report 1) Wood Mackenzie (Expert Report 2) and Morgan Stanley (Expert Report 3) follow the Inquiry's Report.

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[5] Stakeholder submissions are publicly available on the Inquiry's website (www.nsw.gov.au), except for those with commercial-in-confidence advice.

[6] Dr Lila Gurba, Adjunct Senior Research Fellow, School of Biological, Environmental and Earth Sciences, University of NSW.

[7] Dr Kelly Thambimuthu, Chief Executive of the Centre for Low Emission Technology.

1.2 Characteristics of Electricity Generation

What types of generation exist?

Baseload, intermediate and peaking plant

As electricity cannot be stored, it must be generated in the same instant it is consumed. Since demand for electricity varies during the day and across seasons, electrical systems need a mix of plant types that have different characteristics. This allows the system to respond reliably to these variations.

Baseload generation refers broadly to generators that operate at a steady output regardless of total demand for electricity. These plants tend to operate at all times throughout the year, except for when repair or scheduled maintenance work is done. By contrast, peaking generators operate only at times of high demand, such as cold winter evenings and hot summer afternoons when households are using heaters or air-conditioners.

Baseload plants are typically large in capacity, and provide most of the energy supply. They are also slow to fire up and cool down. Baseload generators typically have high capital costs and relatively low operating costs, which means they are well-suited to supplying electricity on a continuous basis. Baseload generation provides for the bulk of Australia's electricity needs. In New South Wales, baseload generators are predominantly coal-fired.

Peaking generators can start up at short notice, operate over a wide range of output and respond rapidly to short-term peaks in demand. In New South Wales, hydro generators have mainly filled the peaking role. However, further potential for hydro peaking plants is very limited. Open cycle gas turbines are now used for peaking duty.

Gas-fired peaking generators typically have lower capital cost (relative to other types of generation) but are expensive to run. Peaking hydro plants are constrained from operating for long periods of time or at a high sustained output by the limited availability of water.

Recurring variations in demand above steady baseload are best met by intermediate plant. Such plants have lower capital cost but higher fuel costs than baseload.

Scheduled generation

Baseload, intermediate and peaking plants provide 'scheduled' generation to the NEM by offering their output to the wholesale market at particular prices or bids. These bids are ranked in ascending price order. The market operator, the National Electricity Market Management Company (NEMMCO), schedules each plant to come into production to meet demand, starting with the plant offering to supply electricity at the lowest price.

Appendix 1.5 illustrates how the relative costs of baseload intermediate and peaking generation affects their optimal levels of utilisation.

Non-scheduled generation

With some generation technologies, operators cannot control when energy will be produced, or how much will be generated at any given time. Such generators are typically dependent on external conditions, and include wind, most solar and run-of-river hydro schemes.

Electricity produced by such generators is called 'non-scheduled generation', and while in operation, displaces the need for scheduled supply whether it be peaking, intermediate or baseload. Non-scheduled generation only operates when external conditions allow, for example, wind generation depends on the availability minute-to-minute of sufficient wind. As such, non-scheduled generation cannot on its own maintain the security of supply of electricity.

Non-scheduled generation from renewable sources is expected to make an increasing contribution to the NSW generation mix over coming decades. Chapter 2 discusses this in detail.

The changing concept of baseload

Competitive wholesale electricity market participants are guided by their own commercial considerations when assessing which type of plant is best suited to run at a particular time. The commercial environment is changeable, and this is reflected in the way different generators are dispatched.

Emerging technologies and policy settings on carbon emissions will affect the relative operating costs of different types of generation. Over time, technologies other than those that have traditionally been associated with baseload generation may also be able to deliver 24-hour-a-day electricity competitively. Chapter 3 discusses this in detail.

What characterises NSW baseload?

Current baseload power stations in New South Wales are based upon black coal-fired water cooled technology[8]. These power stations were deployed between 1968 and 1993. They burn relatively high ash coal of non-export quality which is delivered by rail, conveyor or truck (mainly on dedicated haul roads). Their generating units require approximately 12 to 20 hours to start up from cold. They are unable to operate below about 30 per cent of their maximum output for sustained periods of time.

Baseload capacity in Queensland is similar to New South Wales, except that Queensland's newer plants have technology which uses less coal per unit of electricity generated. The plants have similar operational flexibility to the NSW plants.

Baseload capacity in Victoria is mainly based upon brown coal-fired technology typically built in the 1970s and 1980s. These units are less flexible than either NSW or Queensland baseload units, and require around 15 to 24 hours to start up from cold, with very limited ability to follow changes in overall power required on the system. They are generally unable to operate below about 80 per cent of maximum output for sustained periods of time. Brown coal-fired generators have lower thermal efficiencies and much higher CO_2 emissions per unit of output than black coal-fired generators.

1.3 Key Findings and Recommendations

This section summarises the key findings made in the course of the Inquiry and sets out the Report's recommendations.

New South Wales needs to prepare for baseload supply by 2013-14

- With a risk-averse approach, New South Wales needs to be in a position where new baseload generation can be operational by 2013-14 if necessary, in order to avoid potential energy shortfalls.
- Forecast growth in electricity use implies a need to provide around 91,000 GWh of electrical energy in New South Wales in 2013-14. This is around 10,500 GWh above current annual consumption – equivalent to the yearly output of the Mt Piper power station.

[8] Coal-fired generators can be either water cooled or air cooled. See Chapter 3 for more detail on the different generation technologies.

- Part of this gap will be filled by energy efficiency, new renewable energy generation and increased output from existing generators.
- New South Wales currently imports around ten per cent of its energy needs but growing energy consumption in other States may reduce the amount of energy available over interconnectors.

To be ready for 2013-14 baseload supply needs, preparation should start now

- Based on recent power station developments in Australia, it can typically take up to six years to reach the stage of letting a contract for a new power station. This can be broken down as follows:
    - feasibility, site selection and site purchase (up to two years)
    - environmental assessment, and development and planning approval (up to two years)
    - detailed design and letting of construction contracts – which can be undertaken in parallel with development and planning approval - (one to two years)
    - construction of a coal-fired power station can take up to four years inclusive of pre-commissioning works
    - construction time for gas-fired powers stations can be around two years (plus pre-investment works).

Coal or gas will meet most of the new baseload generation needs

- Most of NSW extra baseload energy needs are likely to be met by coal-fired and/or gas-fired generation as other technologies can only contribute on a relatively small scale or will not mature until 2020 at the earliest.
- New renewable energy generation sources, mainly wind and biomass, are expected to supply 1,375GWh in 2013-14 and about 1,600GWh by 2016-17 (equivalent to replacing the current energy supplied by the Munmorah coal-fired power station).
- Technologies with minimal carbon emissions, such as Solar Thermal, and Geothermal Hot Rock could offer much as baseload generation in the future, but not for stations that are to be operational within the next ten years.

- Nuclear is not an option due to the NSW Government's policy position. In addition, establishing a nuclear energy regulatory framework and planning, building and commissioning a nuclear power plant in Australia is expected to take at least 10 to 20 years.

Ultra-supercritical pulverised fuel coal generation is the only coal-fired technology that can efficiently meet emerging generation needs

- Three types of coal-fired generation technologies were identified by Connell Wagner:
  - Ultra-supercritical Pulverised Fuel coal generation
  - Integrated Gasification Combined Cycle (IGCC) coal generation
  - Ultra Clean Coal (UCC) generation
- As IGCC and UCC technologies are still at the demonstration stage, only Ultra-supercritical pulverised fuel coal generation will be capable of being operational by 2013-14.
- Ultra-supercritical pulverised fuel coal-fired generation has a carbon intensity lower than current plant and will displace less efficient and more carbon intensive coal-fired generation in the merit order of dispatch, thereby reducing the average carbon intensity in the NEM.
- New South Wales has ample resources of coal to supply new baseload coal-fired generation, with estimated recoverable reserves of around 10 billion tonnes. In 2004-05, the NSW coal industry produced 156 million tonnes of raw coal. Existing NSW power stations consume around 30 million tonnes of coal per annum.

Combined Cycle Gas Turbines may be able to meet emerging generation needs

- Combined cycle gas turbines (CCGTs) are capable of running efficiently at high capacity factors. They are cheaper to build than coal-fired generators, but have higher fuel costs, and it is this that reduces their attractiveness for baseload power.
- CCGT technology is amongst the most attractive for new intermediate plant.
- Though not as firm as coal supply, adequate domestic gas is likely to be available for electricity generation until at least 2020 and possibly well beyond.

- As a number of pipeline projects are already progressed in their planning, there is adequate lead time for the projects to be completed by around 2013-14.

Investment in new baseload generation in New South Wales needs greater regulatory certainty about an emissions trading policy

- New investment in electricity generation will occur within a carbon-constrained environment. All States and Territories have committed to long-term emission reduction targets. The Commonwealth Government has promised to establish a long-term emission reduction target in 2008.
- To achieve the long-term target, significant change in the way we generate and use electricity may be required across the National Electricity Market.
- Australia inevitably will have a national emissions trading scheme, commencing no later than 2012. This will allow the market to determine the carbon price within the overall abatement targets.
- Uncertainty over the key design elements of a national emissions trading scheme is delaying necessary investment in new generation, including low emission technologies development.
- The Commonwealth Government should give regulatory certainty by bringing forward the timetable for establishing an emissions trading scheme. At a minimum it should resolve and announce the following key parameters:
  - the national greenhouse gas reduction target and short term caps and associated penalties
  - the basis for allocating emissions permits.

Emissions trading rules will influence the technology choice for new baseload generation

- Combined Cycle Gas Turbines have less than half the carbon emissions of new coal-fired power stations, and will benefit relative to coal from an emissions trading scheme. With a high enough carbon price, combined cycle gas turbines could potentially provide lower cost baseload than coal-fired generation.

- Renewable and low-emission target schemes, such as the NSW Renewable Energy Target will help to accelerate the use of technologies needed to meet long-term emission reduction goals, before and in the early years of an emissions trading scheme.
- Carbon Capture and Storage (CCS) is being actively researched but is unlikely to be developed at utility scale for incorporation in baseload plants until beyond 2020.
- Any new coal-fired generation should provide for retrofitting of Post Combustion Capture (PCC) to facilitate future CCS.
- Manufacturers are able to make generators PCC-ready by allowing space in their designs for carbon capture plants that will be required if PCC is to be retrofitted.
- The indicative costs provided by Alstom in their submission to the Inquiry suggest Ultra-supercritical pulverised fuel technology with PCC will have approximately the same capital cost and better technical performance (availability) than Integrated Gasification Combined Cycle with carbon capture.
- CCS technology is estimated to require up to 30 per cent of the energy generated to be used in the power station and carbon capture process plant. This compares with typically 5 per cent for a power station without CCS.

Energy efficiency measures will play a significant role in reducing electricity consumption

- Energy efficiency can and should play a significant role in helping to achieve the NSW Government's energy and climate change policy objectives.
- Enhanced energy efficiency can contribute to reducing electricity consumption. It is unlikely to offset the need for new investment in baseload generation in New South Wales in the short to medium term.
- The NSW Government should continue to explore options to enhance the role of energy efficiency and consider extra measures to tackle ongoing barriers to the uptake of cost-effective investment in energy efficiency.
- The Government should evaluate the case for replacing the Demand Side Abatement (DSA) Rule with an energy efficiency target and trading scheme in the switch from the existing NSW Greenhouse Gas Reduction Scheme to a national emissions trading scheme. This will help keep incentives for energy efficiency in place.

The National Electricity Market is working efficiently and effectively

- The energy market reforms of the 1990s have established a national and competitive energy market governed by a tested regulatory framework. The success of these reforms means the Government no longer needs to own electricity businesses to ensure security of supply.
- The National Electricity Market (NEM) provides a market that is efficient and protects consumers regarding price, quality, reliability and security of electricity supply.
- Government ownership of electricity businesses operating in the competitive sectors of the industry neither increases nor decreases the State's ability to ensure that price, social and environmental outcomes are achieved from the electricity industry.

The impact on the State could be up to $15 billion to ensure security of supply, compliance with regulatory requirements and commercial competitiveness

- Should the NSW Government choose to continue to own most of the State's electricity industry, the State will almost certainly have to both fund the next tranche of baseload generation in New South Wales and invest further in the State-owned energy corporations. There is no sustainable half-way house. If the Government continues to own businesses operating in the competitive energy market, it needs to accept that these businesses will have to pursue business strategies and investments across the NEM that will allow them to be successful.
- Investment in baseload capacity is but one example of the type of investments that Government would need to fund. The cost of new investment in generation capacity in New South Wales over the next 10 to 15 years is expected to be in the vicinity of $7 billion to $8 billion.
- The Government-owned retail businesses will struggle to remain viable without significant additional capital to allow them to adopt a more vertically and horizontally integrated business model. The potential cost of doing so is in the range of $2 billion to $3 billion over the same period.

- Further, the Inquiry believes Government may be exposed to investing in the order of $3 billion to $4 billion over the next 15 years to retro-fit some existing power stations with carbon reduction technologies.
- While these investments may earn a return, the NSW Government would need to accept that it has less choice over how its limited capital is allocated to meet State Plan objectives and be prepared to make adjustments elsewhere in its capital program and State Budget to account for the increased business risk that such investment entails.
- Alternatively, divesting the retail and generation interests to the private sector would mitigate the need for public funding of the investment in these businesses and would realise proceeds otherwise unavailable to the Government.
- The combined impact of both the divestment of generation and retail and the avoidance of new generation investment means that total State net debt would be up to $26 billion lower in 2020 compared to a 'retain and invest' scenario. This would significantly improve the State's fiscal position and the Government's ability to meet its State Plan objectives.
- The State's business profile and credit rating will benefit from the removal of 'high risk' generation and retail assets from its balance sheet.
- In summary, the Inquiry considers private sector investment will meet the State's emerging generation needs while allowing the Government to achieve its energy and environmental policy goals, maintain the State's credit rating and improve its ability to deliver State Plan objectives.

The Private Sector will invest in baseload generation in New South Wales if a number of conditions are met

- The private sector has demonstrated it will invest in new generation in the NEM under the right conditions (including access to a stable revenue stream, to generation development sites and to fuel sources).
- The private sector can manage the commercial risks in developing a power station but has less capacity to handle policy and regulatory risks. Submissions to the Inquiry highlighted carbon uncertainty and Government ownership as impediments to investment.

- To secure on-going generation investment in New South Wales that is adequate, economic and timely, the NSW Government should transfer its retail and generation interests to the private sector.
- In transferring these interests, the Government will maximise the range of competing potential investors, quarantine risk to the State's fiscal position and AAA credit rating, and realise proceeds not otherwise available and likely to be eroded over time.
- This does not involve selling the 'poles and wires' of the State's electricity transmission and distribution networks.
- The Commonwealth Government should bring forward the timetable for establishing a national emissions trading scheme.

The Inquiry therefore recommends that the NSW Government:

1. Divest the State of the retail arms of EnergyAustralia, Integral Energy and Country Energy.
2. Divest the State of the generation businesses of Macquarie Generation, Delta Electricity and Eraring Energy.
3. In the event that the Government does not wish to sell generation, then it should implement an appropriately structured long-term leasing of current generation assets. The State would retain ownership of the assets, with operational and commercial control by the private sector.
4. Actively monitor the progress of reforms to NSW planning, development approval and environmental licensing process to ensure that proposals for new generation capacity, and associated fuel supplies, are considered expeditiously, and in a cost-effective and predictable manner, without compromising the quality of environmental assessment.
5. Support the planned review of the effectiveness of retail competition by the Australian Energy Market Commission in 2010, and consider the removal of regulated retail price caps at that time, should the review find effective competition in the NSW retail market.

6. Encourage the Commonwealth Government to bring forward the timetable for establishing a national emissions trading scheme. At a minimum the Commonwealth should resolve and announce:
   - the national greenhouse gas reduction target and short term caps and associated penalties
   - the basis for allocating emissions permits.
7. Develop and implement clear and timely transitional rules for existing State-based greenhouse gas and emission schemes to the national emissions trading scheme (in the event of its introduction).
8. Encourage and support energy efficiency initiatives where possible.

2. New Baseload Generation

Key Findings

- With a risk-averse approach, New South Wales needs to be in a position where new baseload generation can be operational by 2013-14 if necessary, in order to avoid potential energy shortfalls.
- Forecast growth in electricity use implies a need to provide around 91,000 GWh of electrical energy in New South Wales in 2013-14. This is around 10,500 GWh above current annual consumption – equivalent to the yearly output of the Mt Piper power station.
- Part of this gap will be filled by energy efficiency, new renewable energy generation and increased output from existing generators.
- New South Wales currently imports around ten per cent of its energy needs but growing energy consumption in other States may reduce the amount of energy available over interconnectors.
- Development applications need to be submitted in 2007 to maintain the options for new base generation to be operational by 2013-14.

2.1 Introduction

Electrical energy consumption in New South Wales has grown by about 1,700 GWh per year for around the past 30 years. TransGrid forecast a slightly slower average growth rate of around 1,600GWh per year over the next ten years in part due to the impact of energy efficiency measures.

New South Wales has had access to surplus generation capacity (including electricity imports from interstate) for the last 15 years. This has been more than sufficient to meet the growth in energy consumption. However, this surplus has reduced significantly as energy consumption has continued to grow.

One of the Inquiry's terms of reference is to review and advise the Government on the need for and timing of new baseload generation to maintain both security of supply and competitively priced electricity in New South Wales.

Simply put, new generation is needed when the consumption of energy is greater than the existing supply of energy. However, actually determining when baseload should be built is more complex, requiring consideration of both whether there is enough electrical energy available, and how best to meet electrical energy needs in a commercially efficient manner which ensures reasonable prices for all consumers, households and businesses.

The Inquiry has focused on understanding the earliest timeframe in which new investment may be required. This does not mean that the Inquiry needs to or should determine the exact year that new investment is required. But the Inquiry does need to understand the parameters that point to the need for early investment.

There is an asymmetry of risk with regard to the timing of new investment and, as such, the Inquiry has taken a risk-averse approach. The additional financing costs associated with completing a new generator one or two years earlier than it is needed are far smaller than the cost to the people of New South Wales and to market participants of not having adequate generation.

A risk-averse approach means being prepared sooner rather than later - being ready so that new generation can be brought online whenever there is a possibility of energy consumption exceeding energy supply. Being prepared maintains flexibility. It does not prevent postponing the construction of a new power station if the time horizon for additional baseload investment moves outwards. Much of the timeframe in preparing for new baseload consists of planning and design. This can be put on hold if the need for new baseload is not confirmed.

The Inquiry agrees with the numerous submissions which noted that the NEM is efficient in providing price signals to investors on the need and timing for investment in new generation. Views expressed in the submissions included:

> '...it is the market, free from impediments, that is best placed to deliver the most efficient and timely investment in all forms of new generation, including baseload.'[1]
>
> '...retailers are generally confident that the National Electricity Market (NEM) can deliver investment of the right type to the right locations in a timely fashion.'[2]
>
> '...The NEM has established a track record of delivering capacity on a timely basis to meet supply requirements thus far, and to date (excluding the impacts of industrial action) there have been no system security issues that have resulted from a lack of supply in the NEM or across individual regions.'[3]

[1] Energy Supply Association of Australia submission, p5

[2] Energy Retailers Association of Australia submission, p1

[3] Babcock and Brown Power, submission p2

The Inquiry agrees that the NEM is well designed to ensure adequate investment, and appreciates that the governments of all NEM jurisdictions have put in place a number of mechanisms, such as through the Reliability Panel of the Australian Energy Market Commission (AEMC) and through NEMMCO's forward looking reserve forecasting to ensure that adequate generation is available.

Having said this, Governments, as well as market participants, take an interest in the appropriate timing for new generation. The Inquiry notes that the NSW Government's role is to ensure that, as far as possible, there are no unnecessary impediments to timely investment.

2.2 Methodology

What is the Inquiry's approach to understanding the need for and timing of new baseload generation?

Since significant modelling and analysis of energy consumption and supply forecasts already exists, the Inquiry did not have to undertake further modelling work.

With a focus on baseload energy, the Inquiry has primarily considered NSW total energy needs over time, rather than the maximum demand for electricity at a single point of time (i.e. baseload energy requirements rather than peak demand).

The objective of the NEM is to ensure the most commercially efficient combination of plant types is used to meet reliability standards. If less efficient options are brought forward, this results in relatively higher electricity costs, which works against the Government's objective to maintain competitively priced electricity.

Baseload and intermediate generators are the most cost-effective generation for providing significant quantities of energy to consumers. By contrast, peak generators are the cheapest to build, but the least efficient and most expensive to run, and are therefore not well suited to providing bulk energy. As shown in Appendix 2.3, peak generators run only at times of peak demand, and contribute very little energy. A need for energy therefore drives a need for baseload and intermediate plant.

Energy consumption forecasts are projections of the amount of electrical energy required to meet consumer needs, usually over the period of one year. Energy consumption forecasts are measured in gigawatt hours (GWh). Forecasts are typically used to estimate the amount of electrical energy that will need to be supplied over a period of time, from all sources including power stations in New South Wales and interconnectors which import electricity into New South Wales from other regions of the NEM, such as Queensland (see section 2.5).

To identify the range of dates within which NSW electrical energy needs might exceed available supply, the Inquiry examined forecasts of the amount of electrical energy that will be consumed in New South Wales and compared this to the amount of electrical energy that can be produced in New South Wales by existing power stations, plus the amount of electrical energy that could be imported into New South Wales via interconnectors.

The energy consumption forecasts used by the Inquiry are taken from TransGrid analysis. As the NSW jurisdictional planning body, TransGrid is responsible for providing forecasting information annually to NEMMCO.[4] This is the same information that was considered by the Inquiry.

Details on the methodology used by TransGrid to calculate energy consumption and the Inquiry's approach to estimating energy supplies are discussed in sections 2.4 and 2.5 respectively. TransGrid's energy consumption and maximum demand forecasts are used by NEMMCO in the preparation of its annual Statement of Opportunities (SOO), which considers the supply-demand balance with a focus on peak demand in the NEM rather than baseload.

The Inquiry did not need to differentiate between intermediate or baseload plant. As discussed in Chapter 3, depending on the carbon price the same technology Combined Cycle Gas Turbines (CCGT) may be used for intermediate and baseload generation.

Whilst peak demand is not the focus of the Inquiry, maximum demand and peak generation are discussed in more detail in Appendix 2.1 and 2.2.

[4] TransGrid was appointed in December 1998 to the role of jurisdictional forecaster by the Minister for Energy. Further information on the forecasting methodology is provided in Section 3 of NEMMCO's 2007 Energy and Demand Projections and in TransGrid's 2007 Annual Planning Report. www.transgrid.com.au.

The mix of existing NSW plant types is discussed in Appendix 2.3 and Figure 2.3.1 shows how peak generation, such as Open Cycle Gas Turbines (OCGT) or hydro generation, contribute significantly to peak capacity (MW) at times of very high loads, but only a small amount of energy (GWh) to NSW annual energy consumption.

The electricity market is dynamic

One limitation that affects all analysis is the dynamic nature of the electricity market. No sooner is the analysis complete, than market conditions evolve and the results start to become outdated. All analysis represents a snapshot in time. It is simply a matter of recognising this limitation, working with the most up to date evidence available, and factoring this limitation (and any others) into the analysis.

While the methodology used by the Inquiry is appropriate to advise government on the range of times within which new baseload generation may be required, such an approach would be limited for a potential investor.

Any investment and risk decisions will ultimately lie with the market participant investing in new generation. Therefore, those investing large amounts of capital in new power stations will, as a matter of course, undertake extensive modelling of their own. The investment decision will have a number of elements to it, including, but not limited to, the investor's detailed analysis of evolving market conditions and their particular business strategies.

Individual investors will determine which type of power station to invest in (baseload, intermediate or peak generation), the precise timing of the investment, and the location of the power station within the NEM.

As in any market, there are a number of variables that can affect the energy balance, which may in turn affect the need for and timing of new baseload generation. These variables are discussed in more detail in section 2.7.

2.3 Energy Consumption Forecasts

The amount of electrical energy that households and businesses consume is the most important factor determining the requirement for new baseload generation.

New South Wales currently uses more electrical energy (79,030 GWh in 2005-06) than any other State. However, on a per capita basis, NSW' energy consumption is only slightly higher than Victoria and South Australia (both have greater gas penetration, for example, for heating and cooking), slightly lower than Queensland and much lower than Tasmania. Energy consumption is growing much more quickly in Queensland than in New South Wales (see section 2.5).

Each year, TransGrid prepares an Annual Planning Report, setting out forecast energy consumption and maximum demand in New South Wales over a 10-year horizon, identifying future constraints in the network and providing options for their removal. The latest forecasts were released in June 2007[5].

Recognising the uncertainties inherent in forecasting, TransGrid prepares three energy consumption forecasts based on low, medium and high growth scenarios. TransGrid takes into account a number of factors when preparing the forecasts, including historical trends, economic data, and known large industrial loads.

TransGrid uses historical energy data obtained from a number of sources, including NEMMCO, TransGrid's internal systems, Distribution Network Service Providers and the Energy Supply Association of Australia.

TransGrid uses economic information provided by the National Institute of Economic and Industry Research (NIEIR) on behalf of NEMMCO.[6] The NIEIR forecasts Gross State Product to increase by an average of 2.8 per cent per year over the forecast period. Population forecasts are also sourced from NIEIR and the NSW population is forecast to grow by 0.9 per cent per year to 2010-11. Large industrial loads account for around 17 per cent of NSW energy consumption.[7]

TransGrid forecasts that total energy consumption in New South Wales will grow at about 1,600 GWh per annum over the next 10 years under their medium growth scenario.[8] This rate of increase is lower than the 1,700 GWh per annum historical average growth and reflects reduced energy consumption, at least in part from energy efficiency measures. TransGrid has not explicitly identified the contribution of energy efficiency measures to reducing growth in energy consumption. Instead, it has implicitly factored in the continuation of the reduced rate of energy growth apparent since around 2001. The difference between the long term energy trend and the TransGrid forecast of total energy required is shown by the difference between the green and red lines in Figure 2.1.

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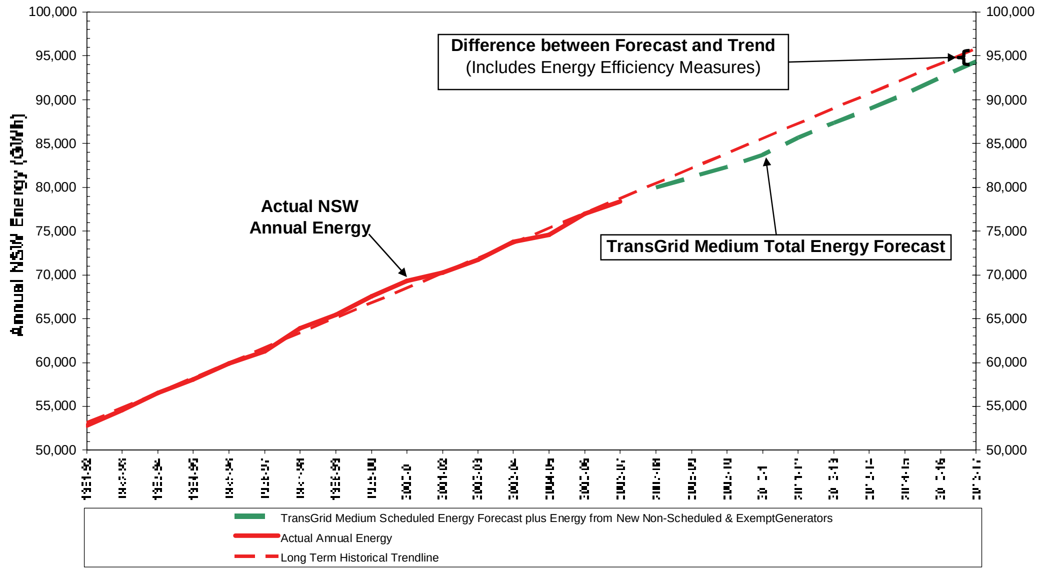
[5] TransGrid, *Annual Planning Report*, 2007

[6] Figure 3.2 and Table 4.1, *The Economic Outlook for NEM States to 2016/17*; *The own price elasticity of demand for electricity in NEM regions*; *Impact of greenhouse policies on the electricity sector supplies and demands*, and *Factors affecting the electricity demand in the NEM*. All reports prepared by the National Institute of Economic and Industry Research for the National Electricity Market Management Company, June 2007.

[7] On an energy sent out basis.

[8] As generated at power stations TransGrid *Annual Planning Report*, 2007, see Table A3.1 and Table 4.5.

Figure 2.1: Actual and Forecast Energy Consumption in NSW, 1991-92 to 2016-17



Source: TransGrid

The trend-line shows the level of energy consumption which would be expected to occur if the historical growth trend is projected forward.

The Inquiry considers that the difference between the energy consumption forecast and the historical growth trend projected forward includes the impact of energy efficiency programs. This suggests that energy efficiency measures will continue to slow the rate of energy consumption growth compared with historical trends.

As shown in Figure 2.1, TransGrid is forecasting total energy consumption in 2016-17 to be some 2,000 GWh lower than it would have been if energy consumption had continued to increase at the pre-2001 rates. However, it is not possible to identify the precise contribution made by energy efficiency to these reduced energy needs.

The actual data for TransGrid's medium growth energy forecasts is provided in Table 2.1.

Table 2.1: NSW Energy Forecast (Medium Growth Scenario)

Financial year		Scheduled Energy (GWh)	Non-scheduled Energy (GWh)	Total Energy (GWh)
1991-92	actual	52,828		
1992-93	actual	54,551		
1993-94	actual	56,531		
1994-95	actual	58,091		
1995-96	actual	59,885		
1996-97	actual	61,260		
1997-98	actual	63,894		
1998-99	actual	65,420		
1999-00	actual	67,569		
2000-01	actual	69,353		
2001-02	actual	70,289		
2002-03	actual	71,687		
2003-04	actual	73,783		
2004-05	actual	74,584		
2005-06	actual	76,979	2,051	79,030
2006-07	estimated	78,400	2,049	80,449
2007-08	projection	79,730	2,300	82,030
2008-09	projection	80,810	2,390	83,200
2009-10	projection	81,920	2,470	84,390
2010-11	projection	82,880	2,890	85,770
2011-12	projection	84,200	3,520	87,720
2012-13	projection	85,770	3,630	89,400
2013-14	projection	87,290	3,710	91,000
2014-15	projection	88,890	3,810	92,700
2015-16	projection	90,720	3,890	94,610
2016-17	projection	92,450	4,000	96,450
1991-92 to 2006-07 average annual growth		*1,700GWh*	*N/A*	
2007-08 to 2016-17 average annual growth		*1,400GWh*	*200GWh*	*1,600GWh*

Source: TransGrid, Annual Planning Report, 2007, p81 & Table 4.5.

The scheduled and non-scheduled energy columns of Table 2.1 are discussed in more detail in section 2.4.

Overall, the Inquiry considers that TransGrid's forecasts are both transparent and reasonable given the available quantifiable data. However, the forecasts do not include any additional major energy intensive industrial load that may develop in New South Wales. Therefore, TransGrid's forecasts could be exceeded if unanticipated additional loads come online.

2.4 Energy Supply Forecasts within New South Wales

This section of the report examines the current energy supply available to New South Wales. It also includes forecasts of how much energy could be supplied by existing New South Wales generators and via interconnectors to meet future NSW electricity needs.

What electrical energy is generated within New South Wales?

Energy needs can be satisfied by energy supplied from scheduled and/or non-scheduled power stations. 'Scheduled' and 'non-scheduled' are terms used to describe how power stations operate within the NEM. Scheduled energy is the portion of energy supplied to New South Wales that is dispatched by NEMMCO as part of the operation of the NEM. In New South Wales, scheduled power stations are generally larger generators, including the major coal-fired units.

Non-scheduled energy is that portion of energy supplied to New South Wales that is usually connected to distribution networks or 'embedded' within consumer premises. This generation supplies a much lesser amount of energy to New South Wales. Renewable energy from wind is included in this. The use of non-scheduled energy displaces the need to take scheduled energy from the grid.

Reflecting the different sources of energy supply, TransGrid forecasts scheduled energy and non-scheduled energy (see Table 2.1). This indicates which sources of energy supply will satisfy energy consumption. The scheduled energy is the one which determines the amount of baseload energy supply.

Scheduled generation - capability of existing New South Wales plant

Scheduled electricity supplies are sourced from a range of power stations with different capabilities and constraints. In New South Wales, scheduled generation is mainly from coal-fired generators.

It was important for the Inquiry to understand the full capability of scheduled electricity sources – both maximum power output and maximum annual energy – in order to identify the likelihood of shortfalls in the future NSW energy balance.

Table 2.2 provides a forecast of the maximum energy supply from each NSW generator and indicative projections of the maximum energy supply capability based on capacity factors provided by Connell Wagner (Appendix C of Expert Report 1) for the major NSW power stations.

The capacity factor is the amount of energy delivered by a generator, divided by the amount of energy that would have been delivered had the generator run continuously at its maximum (nameplate) output, expressed as a percentage. The "Maximum Technical Capacity Factor" and "Expected maximum energy capability" columns in Table 2.2 refer to the maximum capacity factors and energy outputs achievable due to technical limitations. They do not take in to account commercial or competitive considerations.

Table 2.2 does not provide energy supply forecasts from renewables and embedded generation within New South Wales which is discussed below.

Table 2.2: Existing or Committed Generation in NSW

Generator	Ownership	Year Commissioned	Fuel	Nameplate Rating (MW)	Expected maximum. energy capability (GWh/ annum) (i)	Maximum Technical Capacity. Factor (%) (i)
Munmorah	Delta Electricity	1968-69	Coal	700	0(ii)	0
Liddell	Macquarie Generation	1971-73	Coal	2,000	13,000	74
Wallerawang	Delta Electricity	1976-80	Coal	1,000	6,500	75
Vales Point	Delta Electricity	1978-79	Coal	1,320	8,700	75
Eraring	Eraring Energy	1982-84	Coal	2,640	20,800	90
Bayswater	Macquarie Generation	1985-86	Coal	2,640	20,800	90
Mt. Piper	Delta Electricity	1992-93	Coal	1,320	10,400	90
Redbank	Babcock & Brown	1999	Coal	150	1,000	76
Bendeela	Eraring Energy	1977	Hydro	80	Negligible	-
Kangaroo Valley.	Eraring Energy	1977	Hydro	160	Negligible	-
Smithfield	Marubeni	1995	Gas	160	1,000	72
Tallawarra	TRUenergy	2008	Gas	440	2,300	60
Colongra	Delta Electricity	2009-10	Gas	660	300	5
Uranquinty	NewGen	2009-10	Gas	600	300	5
Total					**85,100(iii)**	

(i) Maximum capacities – output and annual energy capability – on nameplate rating as supplied by submissions to the Inquiry and reviewed by Connell Wagner. These capabilities do not take into account any plant limitations that have recently been experienced following drought conditions in eastern Australia.
(ii) Delta Electricity note in their submission that it would be necessary to significantly refurbish Munmorah power station to extend its life beyond 2012. Munmorah's output has therefore not been included in this table.
(iii) The expected maximum energy supply capability of existing and committed power stations within NSW is at most 85,100GWh/annum. This is on the assumption that the maximum capacity could be sourced co-incidentally from each power station.

Some submissions to the Inquiry suggested that coal-fired generators in New South Wales could supply more energy by running at capacity factors similar to coal-fired generators in Victoria or Queensland. AGL said that, 'If existing coal-fired generators in New South Wales operated at capacity factors comparable to coal-fired generators in Victoria and Queensland (around 80 per cent) an additional 15,000 GWh of energy per annum would be available'.[9]

Connell Wagner has reported that the capacity factor, and hence the annual energy output of some coal-fired power stations in New South Wales, is constrained by technical limitations (see Appendix C of Expert Report 1).

For example, the high ash content coal and the high gas velocity design of boilers at some power stations in New South Wales lead to high boiler erosion rates especially when plants are operating at or near full output. This constrains the technically achievable maximum capacity factor of some plant. Running these plants at high capacity for long periods would lead to reliability degradation as boiler tubes wear, and/or a need for more regular and major boiler maintenance.

The three newer large plants in New South Wales (Bayswater, Mt. Piper and Eraring) have much lower gas velocities, and hence can run at higher capacity factors. There are also fuel differences between New South Wales coal-fired generators, which use black coal, and Victorian coal-fired generators which use brown coal. Due to the nature of the fuel, Victorian brown coal generators have very low gas velocities and therefore do not suffer significant erosion issues.

Delta Electricity has advised the Inquiry that, in its present condition, the Munmorah power station (600MW) cannot fulfil a normal baseload role. Delta indicated in its submission that there is 'Necessary refurbishment to extend the life of Munmorah Power Station beyond 2012'. A refurbishment of Munmorah 'increases the capacity of each unit by 50MW but essentially represents a 700MW increase to baseload capacity beyond 2012'.[10]

[9] AGL submission, p 4

[10] Delta Electricity submission, p 47.

As refurbishment represents a substantial investment in itself, the Inquiry considers that it is an investment option for meeting baseload energy requirements, and its output has not been included in Table 2.2.

Based on Table 2.2, generating plant in New South Wales is capable of delivering up to approximately 85,000 GWh of energy per annum. However, this assumes that all generators are running to their maximum technical capacity factor limits, and that they do this year after year.

The Inquiry acknowledges that there is a significant down-side risk. Due to refurbishment plans generation may not be fully available every year. Also, most of these plants have never previously achieved the high annual capacity factors used in Table 2.2 and issues may emerge as they are run harder.

Connell Wagner states that "The capacity achieved depends on many factors including technical, environmental, their performance in the National Electricity Market and the aging of the stations. Consequently the outcome from year to year will vary and it is unlikely the maximum capacity factors for all stations could be achieved in any year".[11]

The Inquiry therefore considers that the maximum output available from existing NSW plant is less than 85,000 GWh, assuming no significant contribution from the existing Munmorah units.

Non-scheduled energy

Non-scheduled energy is usually connected to distribution networks or 'embedded' in consumer power systems, and includes most renewable energy. Compared to scheduled energy supplies, non-scheduled energy supplies are small, around 2,000 GWh in 2005-06.

Another major factor responsible for the lower growth forecasts in scheduled energy is TransGrid's allowance for stronger contributions from non-scheduled generation in New South Wales. TransGrid estimates that by 2016-17, non-scheduled energy will supply around 4,000 GWh per year within New South Wales.

The majority of this generation is expected to be from renewable sources connected to distribution networks. This estimate is prepared by NIEIR for NEMMCO, and includes the impact of newly introduced renewable energy targets in New South Wales, Victoria and South Australia.[12]

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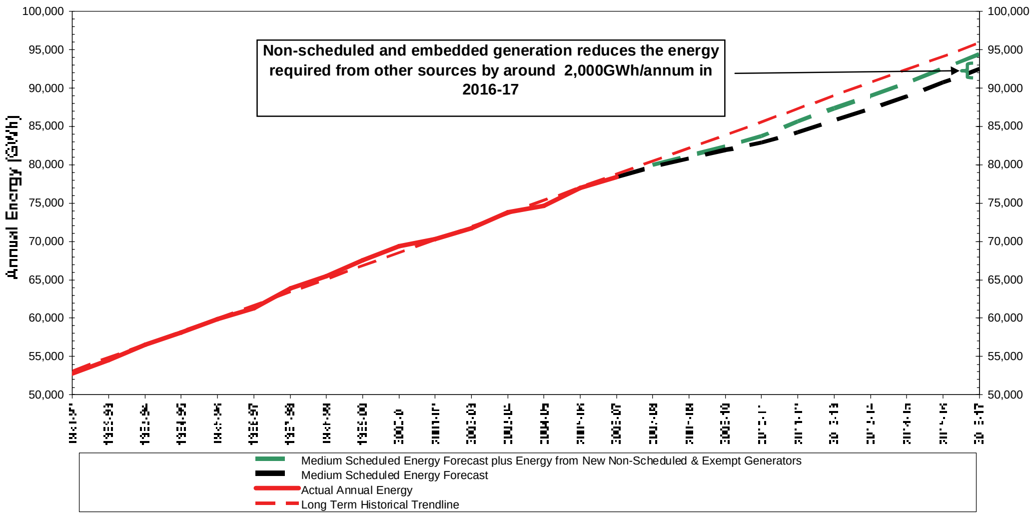
[11] Expert Report 1, section 8.6.

[12] NIEIR (2007) Projections of Non-scheduled and exempted generation in the NEM, *A report for the National Electricity Market Management Company*, Prepared by the National Institute of Economic and Industry Research.

This increase in renewable energy supplies is largely due to the Commonwealth Mandatory Renewable Energy Target (MRET) scheme and the NSW Government's decision to introduce a 15 per cent Renewable Energy Target. NIEIR forecasts indicate this target will result in an average increase in supply from NSW renewable sources (primarily wind and biomass) of more than 150GWh each year. [13]

Another 50 GWh per year annual increase is forecast to come from gas generation embedded in distribution or customer networks. The impact of this forecast renewable and embedded generation on energy requirements is significant, and is shown by the difference between the green and black lines in Figure 2.2.

Figure 2.2: Forecast increase in the contribution of non-scheduled electricity generators in NSW, 1991-92 to 2016-17



Source Data: TransGrid

[13] NIEIR (2007) *Projections of non-scheduled and exempted generation in the NEM, 2006-07 to 2022-23, A report for the National Electricity Market Management Company*, June 2007

The Inquiry notes that renewable energy targets in Victoria, South Australia and New South Wales are in their infancy. Whilst NIEIR has taken account of these renewable energy targets in their forecasts for non-scheduled energy supplies, there is still a degree of uncertainty over where the generation required to meet the targets will be placed. NIEIR note that there are a number of uncertainties in their forecasts and that "...extreme care should be exercised when using these figures."[14] Approvals for some wind farms have also been problematic.[15]

Some submissions to the Inquiry have suggested that additional capacity from non-scheduled generation (i.e. renewables) may be available in New South Wales[16.] However, as noted above, it will be some time before a clear picture emerges on the extent of the additional energy supplies that will be located in New South Wales.

Having said this, the Inquiry notes that renewable energy supplies will play an increasingly important role in the generation mix in New South Wales.

2.5 Electrical Energy Available from Imports to New South Wales

As shown in Figure 2.3, New South Wales is connected to the Queensland, Snowy and Victorian regions by 330 kV interconnectors. New South Wales currently imports significant amounts of energy from the Queensland and Snowy regions.[17]

Inter-regional transmission has provided efficiency and reliability benefits to New South Wales over many years.

The New South Wales and Victorian power systems have been interconnected via the Snowy region for almost 50 years and the Queensland-NSW Interconnector (QNI) was completed in 2000-01. Interconnections provide an important part of all the NEM States' energy and peak demand balance.

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[14] NIEIR (2007) *Projections of non-scheduled and exempted generation in the NEM, 2006-07 to 2022-23, A report for the National Electricity Market Management Company*, June 2007, p. i

[15] For example, in April 2006 the Federal Government rejected a Wind Power's wind farm development at Bald Hills in South Gippsland, reportedly because of the risk it posed to the Orange-Bellied Parrot. In August 2007, AGL abandoned its planned Gippsland Wind Farm. According to The Australian, about 1500 objections has been lodged against the project.

[16] For example, EPURON's supplementary submission of 17th August suggested that NSW renewables had potential for "production of 9,500 - 13,000 GWh/an of diversified, dependable power".

[17] On 30 August 2007 the Australian Energy Market Commission determined the Snowy Region would be abolished from 1 July 2008. This is not a physical change to the amount of generation or the transmission network and so does not impact on the Inquiry's conclusions.

In 2006-07, inter-regional supplies contributed about 9,000 GWh to New South Wales', which is over 10 per cent of New South Wales' energy needs.

Each interconnector has a maximum limit to the amount of energy it can supply. The amount of energy available to New South Wales also depends on the energy consumption in the other regions of the NEM and relative costs of supplying energy to each region. If energy is more expensive in New South Wales, then energy is likely to be supplied from Queensland to New South Wales. The converse is also true.

Energy will from time to time flow from the region with higher average generation costs to the region with lower average generation costs but on average energy will flow towards the region with higher generating costs.

The process of determining the least cost option for supplying energy across the NEM to meet growing energy consumption in the different NEM regions is complex. The Inquiry has considered some high level scenarios as to how growing energy consumption in different NEM regions and the relative costs of generation will influence energy supplies between the NEM regions.

Market participants and proponents of new generation need to make an assessment of the levels of energy supply to New South Wales from adjoining NEM regions and model that as part of their investment strategies. The potential for interstate transmission augmentation is further discussed in Appendix 2.4.

Figure 2.3: Main NSW and Snowy Transmission System

Source TransGrid

Energy growth in other NEM regions

Additional growth in energy consumption in Queensland may result in less energy being available to New South Wales. Similarly, energy consumption growth in Victoria may result in additional energy transfers south from Snowy, leaving less energy available to New South Wales.

The Inquiry has not undertaken detailed modelling of the likely impact of growth in energy consumption in other NEM regions on the interconnector energy supplies to New South Wales.

However, forecasts recently developed by the State appointed Jurisdictional Planning Bodies (JPB) and published by NEMMCO in July 2007 expect scheduled annual energy consumption to grow over the next 10 years (2006-07 to 2016-17) by 22,000 GWh (3.5 per cent per annum) in Queensland and 8,000 GWh (0.8 per cent per annum) in Victoria/South Australia/Tasmania.[18] This compares[19] with scheduled energy consumption growth in New South Wales of 14,000 GWh (1.7 per cent per annum). Scheduled energy growth in the Victoria/South Australia/Tasmania regions is low in part due to the high contribution assumed from non-scheduled generation driven by renewable energy targets. An additional 6,000GWh of non-scheduled generation is expected in Victoria by 2016-17 compared to 2,000GWh in New South Wales,[20] reflecting the better quality of wind resources in Victoria.

Future energy supplies from Queensland

The high forecast growth of energy consumption in Queensland is expected to rapidly absorb any under-utilised energy supply capacity in that region. Last year, the Queensland-NSW Interconnector (QNI) transferred almost 6,000 GWh of "net energy" to New South Wales – that is, the difference between energy supplied south and energy supplied north. An energy transfer of that magnitude may be very close to the practical maximum capacity factor limit of QNI.

The new Kogan Creek power station is likely to be capable of providing around 6,000 GWh of Queensland's forecast increase of 22,000 GWh by 2016-17. As with New South Wales there may be some potential to further increase the capacity factors of existing generators. But it is likely that some of the energy required by Queensland could come from energy that would otherwise flow to New South Wales.

[18] NEMMCO *"Australian National Electricity Market - 2007Energy and Demand Projections", Summary Report*, July 2007.

[19] 14,000GWh and 1.7 per cent refer to scheduled energy growth. For total energy growth, the figures are 16,000GWh and 1.8 per cent.

[20] Tables C2 and B2, *Projections of Non-scheduled and exempted generation in the NEM, A report for the National Electricity Market Management Company*, prepared by the National Institute of Economic and Industry Research (2007)

Investing in additional generation in Queensland to support New South Wales' energy needs is not necessarily optimal. Energy generated for New South Wales in Queensland is subject to significant additional transmission losses. Furthermore, Queensland generation is at greater risk of being "constrained off" due to interconnector capacity limits, meaning that Queensland generators face the risk of not being able to fully deliver their power to New South Wales at times of high NSW electricity prices.

For these reasons, new Queensland baseload generation (beyond that required for Queensland's own needs) is only likely to occur if Queensland generation has significant cost advantages over New South Wales.

As discussed in Chapter 3, new scheduled baseload generation is likely to be either coal-fired or gas-fired, and generating costs will be driven largely by the cost of these two fuels.

The Inquiry considers that there is a high degree of uncertainty around any fuel cost differentials between New South Wales and Queensland. For example, ACIL Tasman forecast the gas price in Central New South Wales to be nearly 30 per cent higher than the gas prices in South East Queensland[21], and that gas availability restricts New South Wales to a total of three combined cycle gas units in the next ten years[22].

Conversely, as noted in Chapter 3 and in submissions, whilst Queensland currently has cheaper gas, there is significant upside potential for coal seam methane gas reserves in New South Wales in the medium term. If these were developed, the relative price differential between Queensland and New South Wales could change dramatically over the next few years. Limitations on future New South Wales gas availability also appear to be falling away.

Similarly, ACIL Tasman have forecast Queensland coal prices to be around 15 per cent cheaper than NSW coal,[23] whilst submissions to the Inquiry have suggested a lower cost for NSW coal.[24]

[21] Figure 9 in ACIL Tasman, *"Fuel resource, new entry and generation costs in the NEM – Report 2 – Data and Documentation – Draft report prepared for NEMMCO"*, 27th March 2007.

[22] Ibid, Table 58

[23] Ibid, Table 15

[24] Macquarie Generation submission, p19

If fuel prices were similar in Queensland and New South Wales, more generation development would take place in New South Wales and less development would take place in Queensland, as there would be no benefits to new Queensland generators that would outweigh the cost of transmitting electricity long distances to New South Wales.

For the purpose of this analysis, the Inquiry has taken the view that in the long term, net electrical energy imports from Queensland are likely to be no higher than about 6,000 GWh, and could be markedly reduced over the next ten years.

Future energy supplies from Snowy Hydro

Annual consumption of scheduled energy in Tasmania, South Australia and Victoria is expected to grow by around 8,000 GWh over the next ten years, and those States may draw more energy from Snowy than they have previously. Snowy Hydro supplies energy to Victoria and New South Wales. In the NEM, Victoria is linked to Tasmania and South Australia. The energy consumption in one region can therefore affect available energy supplies in another region.

Energy generated by Snowy Hydro averages about 4,800 GWh per annum assuming no withholding of water for drought recovery[25].

New South Wales has historically consumed most of the net energy supplied by the Snowy Hydro Scheme. However, increasing energy consumption in Victoria, South Australia and Tasmania may mean that significantly more of Snowy Hydro's energy is supplied to Victoria.

Whilst ACIL Tasman is forecasting gas prices in Victoria that are currently lower than gas prices in New South Wales, development in coal seam gas and access to abundant black coal may make high energy output baseload plant cheaper to operate in New South Wales than in Victoria, South Australia or Tasmania. This may mean that it is cheaper to meet the additional energy needs of the States south of Snowy Hydro by increasing the energy flows from Snowy Hydro to the south, and by reducing the energy flows to the north.

Unlike Queensland generation, Snowy generation is equally remote from both northern and southern loads, so there are limited loss factor differences in supplying net energy in a particular direction.

If additional energy was required to the south of Snowy Hydro, then the energy available to New South Wales could drop over time from around 3,000 GWh per annum to zero or even negative.

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[25] NEMMCO 2006 Statement of Opportunities, page 4-11

2.6 Timing of New Baseload Generation

The Inquiry has considered all submissions on the timing of new baseload. There is significant variation in the analysis of when new generation is required. A number of submissions and NEMMCO's 2006 market simulation[26] suggested new intermediate or baseload plant will be required around 2013[27].

Some other submissions[28,] and previous modelling carried out by NSW Government agencies considered that new intermediate or baseload generation would be required at a later time, for example, around 2016-17. The differences in anticipated timing are largely due to different assumptions about energy efficiency measures, embedded and renewable generation, maximum existing NSW generator capacity factors, inter-regional flows driven by differences in regional fuel costs and fuel and operating costs of existing NSW plant.

Both Origin Energy and TRUenergy recognised the importance of these assumptions.

'Origin's modelling suggests baseload discussions revolve around three key dates:

- Assuming full interconnection and availability of supply from other states, baseload is not required until about 2017
- Assuming interconnection cannot be fully relied upon, baseload is not required until about 2015 (it also becomes economic for generators to build baseload around this time)
- Demand for swap contracts to meet average demand, is projected to exceed supply from 2014 in NSW.'[29]

'In summary, we believe base load investment could be required from as early as 2012, however there is significant uncertainty in the forecast, and credible cases can be made out to 2015/16'.[30]

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[26] NEMMCO submission, p3 also stated that 'It should be noted that whilst the 2006 NEMMCO modelling suggest a commercial opportunity at this time, this is not the same as the timing of an energy shortfall'"

[27] NEMMCO 2006 SOO, (2010/11 for CCGT beyond Tallawarra, 2012/13 for Coal) Appendix H8; Eraring Energy Submission, (2012/13) p.2; ANZ submission (2010/11) p1; Babcock & Brown Power submission (2013) p.3; Delta Electricity submission (2013/14) p.1; EnergyAustralia submission (2014) p.2; Origin Energy (with reduced interconnector flows 2015) p.7.

[28] Macquarie Generation submission (2015/16) p.10; Origin Energy Submission (2017) p.6, Climate Institute submission (>2017) p.2.

[29] Origin Energy submission p2.

[30] TRUenergy submission p7.

Notwithstanding the different views on this matter, the Inquiry finds that it is likely that new generation will be required in New South Wales within the period 2013 to 2017. It could possibly be slightly earlier for generators initially operating as intermediate plant, but notes that the actual timing will be dependent on both market and project specific considerations.

TransGrid's low, medium and high scenarios for scheduled energy consumption forecasts are set out in Table 2.3 below.

Table 2.3: NSW Scheduled Energy Consumption, by Growth Scenario

Year	2007-08 GWh	2008-09 GWh	2009-10 GWH	2010-11 GWh	2011-12 GWh	2012-13 GWh	2013-14 GWh	2014-15 GWh	2015-16 GWh	2016-17 GWh
Low	79,420	80,040	80,560	81,110	81,820	82,590	83,140	83,880	84,720	85,560
Medium	79,730	80,810	81,920	82,880	84,200	85,770	87,290	88,890	90,720	92,450
High	80,130	81,870	83,970	85,770	87,880	90,390	92,830	95,370	98,220	101,050

Source: TransGrid[31]

As outlined, the range of annual scheduled energy available to New South Wales could be as follows:

- NSW existing generation[32] less than 85,000GWh
- From Queensland: 0 to 6,000GWh
- From Snowy/Victoria: 0 to 3,000GWh.

As set out in Chapter 3, different technologies have different lead times for commissioning. Coal-fired generation can be delivered is 2013,[33] whilst the earliest date that gas-fired CCGT generation could be available is 2010-211.[34,] Based on the above consumption forecasts and available energy, there are plausible scenarios where high energy plant would be required by these times.

[31] The medium growth scenario is published on page 81 of the TransGrid's *Annual Planning Report*. High and low scenarios were provided directly to the Inquiry by TransGrid.

[32] See Table 2.4

[33] Page 3 of Eraring Energy's submission suggests a possible 2012 commissioning. Page 46 of Delta Energy's submission suggests 2013-14. The Inquiry has adopted the more conservative timing estimate. Timing is discussed further in Chapter 3.

[34] For example, Delta's Bamarang proposal already has planning approval (Delta submission, p47) .and could in theory be built in two to three years. Proposals without planning approval will take longer.

For instance, the medium energy consumption in 2013-14 is 87,290GWh, which means that over 2,000GWh needs to come from other regions even if all plants run at full capacity. If the high forecast of 92,830GWh is realised, then at least 7,830GWh needs to be imported.

The Inquiry recommends that all baseload options remain available. In order to ensure that a coal-fired option remains open, market participants need to submit development applications before the end of 2007. It is relatively simple to curtail the progress of these projects at any time prior to entering construction contracts should they not be required, or be required at a later date.

If necessary, additional energy needs prior to 2013-14 can be met with gas-fired plant and/or a refurbishment of Munmorah power station. New South Wales already has sites with development approval for additional combined cycle gas generators and construction would take two to three years. Additional development applications will be required in the next one to two years if combined cycle gas proves to be the best form of generation for providing the bulk electrical energy needs of New South Wales.

The process for addressing energy supply shortfalls and the environmental planning and assessment processes are discussed in more detail in Appendices 2.6 and 2.7.

2.7 Key Variables

What variables affect the timing of new baseload generation?

As previously mentioned, there are a number of variables which affect the energy balance in New South Wales. These variables will influence the need for new baseload generation. This section summarises the key variables (interconnection, capacity factors, renewable power stations, large industrial projects and energy efficiency) which have been identified as having a significant influence on the need for new baseload generation.

Supply – interconnection

The extent to which New South Wales can import energy supply from other NEM regions via interconnectors is influenced by the factors discussed in section 2.5.

Supply – capacity factors

The capacity factors of existing NSW plant is discussed in section 2.4.

Impact of drought

Water is an important component of electricity production, as it can be used as a source for hydro generation or as part of the production process (cooling for coal-fired and CCGT generators) .The Inquiry notes that drought can also influence capacity factors.

As discussed in Appendix 2.5, in the first half of 2007, upward pressure on wholesale electricity prices followed generator capacity and energy restrictions in the NEM as a result of the drought and maintenance outages. For instance, the drought has caused the Snowy Hydro Scheme to shift some electricity production to its more expensive gas-fired plants in Victoria. There have also been generation reductions at South-East Queensland power stations following water scarcity.

Ensuring that any continuation of the drought does not impact on the security and reliability of NSW power supplies is a high priority. The Inquiry notes that the NSW generators have already undertaken measures to secure water supplies for power stations, including building a new recycled water treatment plant at the Vales Point power station to replace fresh water. The Inquiry also notes that the NSW Government has also announced that it will establish a 40 billion litre strategic water reserve to protect NSW power generation.

Water storage levels at dams that supply the major NSW inland power stations (Bayswater, Liddell, Mt Piper and Wallerawang) received inflows following the wet weather in June and early July. The Inquiry notes that NEMMCO released an updated version of its drought report, in which it is indicated that the extent to which the drought is affecting the generating capacity of power stations is easing.[35]

Factors such as drought add to the asymmetry of risk when considering the need for and timing of new baseload generation.

Renewable energy

The NSW Government's commitment to renewable energy has already been factored into the forecasts. However, there is uncertainty around the likely siting of renewable generation.

Due to the wide-ranging opinions about the extent to which renewable sources of energy are able to supply baseload generation needs, the Inquiry considers that this also adds to the asymmetry of risk when considering the need for and timing of new baseload generation.

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[35] *'Drought Scenarios Investigation: August 2007 Update'*, NEMMCO, 2007

Energy efficiency

Current energy efficiency efforts are already implicitly factored into the TransGrid forecast. Demand-side abatement under the NSW Greenhouse Gas Reduction Abatement Scheme (GGAS), the Building Sustainability Index (BASIX), energy efficiency standards, the Climate Change Fund and greenhouse gas emission reduction targets will all play a key role in reducing the consumption of energy.

There is debate about the extent that energy efficiency measures are able to defer the need for new baseload energy. This issue is discussed in more detail in Chapter 4. There may be new methods to reduce energy consumption in the future. The Inquiry notes that effective new energy efficiency and demand management could affect the timing of the new supply – but that it does not obviate the need to be prepared now.

Large industrial projects

Any large new energy intensive industrial project in NSW could be expected to bring forward the timing of new baseload energy supplies, as it would significantly contribute to the future consumption of electricity. Such projects are often not incorporated in forecasts for energy consumption, unless publicly announced.

The Australian Bureau of Agriculture and Resource Economics (ABARE) notes that the growth in energy intensive industries (e.g. aluminium, alumina and iron/steel) is expected to continue, but it does not list any new large energy intensive industrial projects for New South Wales.[36]

The Inquiry notes again that the potential for such a development adds to the asymmetry of risk when considering the need for and timing of new baseload generation.

[36] Cuevas-Cubia, C and Riwoe, D., *Australian Energy, National and State Projections to 2029-30*, 2006.

3. Technology Options

Key Findings

- Most of NSW extra baseload energy needs are likely to be met by coal and/or gas-fired generation as:
- other technologies can only contribute on a relatively small scale or will not mature until 2020 at the earliest
- adequate gas is likely to be available until at least 2020, and probably well beyond, for electricity generation utilising high efficiency combined cycle gas turbine (CCGT) technology
- ample domestic coal is available for the foreseeable future, with near-term needs being met from coal-fired technology using high efficiency ultra-supercritical steam conditions.
- New coal-fired generation plants should allow for retrofitting of carbon capture and storage (CCS) technologies.
- CCS technology is estimated to require up to 30 per cent of the energy generated to be used in the power station and carbon capture process plant. This compares with typically 5 per cent for a power station without CCS.
- The contribution from wind is likely to be by way of displacing energy which would otherwise be generated by burning coal. Wind turbines typically operate at a capacity factor of around 30 per cent in New South Wales. Only 5 to 10 per cent of total installed wind turbine capacity can be considered firm during peak periods.
- Biomass technology can be used for small scale baseload plants provided a continuous supply of fuel at reasonable cost can be sourced.
- Solar thermal with energy storage, and geothermal hot rock technologies have potential to be utilised for baseload generation in the medium term but are at an early stage of development.
- Nuclear is not an option due to the NSW Government's policy position. In addition, establishing a nuclear energy regulatory framework and planning, building and commissioning a nuclear power plant in Australia is expected to take at least 10 to 20 years.
- Planning approval is needed in the immediate future to maintain the potential for new baseload developments to be delivered from 2013-14.
- The COAG Ministerial Council on Energy should further align electricity and gas laws as these markets and infrastructure are becoming more interdependent.

3.1 Introduction

This Chapter examines the technologies available to meet additional baseload requirements within the next 10 years. In particular, it addresses the technology component of the second and third terms of reference of the Inquiry:

- Examine the baseload options available to efficiently meet any emerging generation needs
- Review the timing and feasibility of technologies and/or measures available both nationally and internationally that reduce greenhouse gas emissions.

This Chapter also examines coal and gas availability, and the potential sites and development paths to utilise technologies identified to meet any emerging generation needs.

Options, such as energy efficiency measures or emissions trading schemes that are not directly related to a technology are dealt with in Chapters 4 and 5 respectively.

Baseload generation provides the majority of electrical energy to NSW customers. The competitiveness of the NSW economy, and the affordability of energy to NSW consumers is enhanced if baseload electricity is provided at reasonable cost.

Important considerations in selecting a baseload technology include the capital and operating cost, efficiency of conversion of primary energy to electricity, the ability of the plant to meet acceptable environmental performance criteria, and the proven nature of the design and components making up the plant to ensure reliable operation.

High efficiency of conversion helps limit the quantity of fuel required to produce a given quantity of electricity. This conserves resources, and in the case of fossil fuels, limits the carbon intensity of the conversion process. Improving efficiency is also being driven by the anticipated introduction of emissions trading. High efficiency has implications for fuel supply costs, environmental impact and commercial viability.

Plant components or designs which are unproven, or have demonstrated poor reliability, or are at an early a stage of development are an unacceptable risk, given the high reliability requirements of the electricity system. Providers of finance for power projects are risk-averse and an unproven technology would find it difficult to secure financial backing.

In discussing technology maturity the following terminology is often used:

- **Research Phase** - the basic science is understood, but the technology is currently in the stage of conceptual design or testing and has not been demonstrated in a pilot plant.
- **Demonstration Phase** - the technology has been built and operated in a pilot plant. Further development is required before the technology is ready for design and construction of a full-scale plant.
- **Economically Feasible under specific conditions** - the technology is well understood and used in selected commercial applications, for instance if there is a favourable policy measure in place but relatively (less than five) plants in operation.
- **Mature Market** - the technology is in operation with multiple plants operating worldwide.

An additional consideration is the availability of water for cooling. Limited water is requiring consideration of dry cooling methods, which have higher capital costs, lower output and thermal efficiency, with resulting higher carbon intensity.

In addressing greenhouse gas emissions associated with fossil fuels used for electricity generation, the Inquiry reviewed the major research and development programs underway on CCS.

Methodology

The Inquiry sought advice in four key areas:

- Potential baseload generation technologies likely to be available as the next tranche of baseload capacity in New South Wales (advice provided by Connell Wagner).
- Potential carbon emission reduction technologies, such as carbon capture and storage (advice provided by Connell Wagner, with assistance from Dr Lila Gurba and peer review from Dr Kelly Thambimuthu).
- Ongoing availability and cost of gas supplies for baseload generation in New South Wales (advice provided by Wood Mackenzie).
- Potential sites and development paths for new baseload generation in New South Wales (advice provided by PVS & Associates).

A range of cost estimates has been provided by Connell Wagner for each technology. These cost estimates are indicative only. Where total costs are provided, these do not include any adjustments for the NSW Greenhouse Gas Reduction Scheme or the anticipated national emissions trading scheme.

The Connell Wagner (Expert Report 1) and Wood Mackenzie (Expert Report 2) reports follow the Appendices in this Report.

The discussion in this Chapter is based on the outcomes of the above consultants' advice, augmented where necessary by other publicly available data and submissions to the Inquiry.

This information increased the Inquiry's understanding of what was possible and what was unlikely over the next decade. The Inquiry does not need to pick a technology. Rather given the uncertainties with technology development, the Inquiry considers that all viable options should be kept open at this stage.

For any investment the technology and market risk will lie with the market participants investing in new generation. Investors will undertake considerably more analysis to ensure their technology choice fits with their understanding of the evolving market conditions and their business strategies.

The Inquiry has approached its work in a technology neutral manner. As market conditions evolve and in particular when an emissions trading regime is introduced, the relative attractiveness of different technologies will change. The impact of an emissions trading scheme is discussed in Chapter 5.

3.2 Generation Technology Options

Connell Wagner identified and examined possible technology options for providing baseload energy to New South Wales by:

- identifying electricity generation options
- determining which options may be applicable for baseload generation in New South Wales
- examining in more depth potentially viable technology options.

The importance of greenhouse gas emissions lead the Inquiry to consider technologies in terms of whether they come with low carbon emissions or higher carbon emissions.

The term ‘low’ (rather than ‘zero’) carbon emissions is used as all technologies have some carbon emissions associated with their fuel extraction and/or construction phases even though they operate with essentially zero emissions. The International Energy Agency (IEA) has compiled estimates of CO_2 emissions for a range of electricity generation technologies.[1]

Low carbon emissions technologies which are mature and could be utilised (subject to resource constraints) are hydro, wind and biomass, whilst solar thermal and geothermal hot dry rocks are considered to be prospective.

Nuclear is a mature technology which is associated with low carbon emissions. Both NSW Government policy and the absence of a nuclear energy regulatory framework rules out this option for New South Wales.

Higher carbon emissions technologies which are mature and could be utilised include coal-fired plant with ultra-supercritical steam conditions, gas-fired open cycle gas turbine (OCGT) plant and combined cycle gas turbine (CCGT) plant. A further technology which is considered prospective is Integrated Coal Gasification Combined Cycle (IGCC), whilst Ultra Clean Coal Combined Cycle (UCC) could be prospective in the longer term.

All of the above technology options are described in more detail in this section of the report.

A number of other technology options are able to generate electricity but are not considered viable for baseload generation in New South Wales. For completeness these technologies are listed in the Table 3.1 together with the reasons why they have not been considered further.

Table 3.1: Technologies identified as not suitable for baseload generation in NSW

Technology	Reason for not considering further
Ocean Wave	Immature – demonstration phase
Ocean Tidal	Not suitable for NSW – tidal range too small.
Solar Photo-voltaic	Expensive – solar thermal much cheaper
Geothermal Aquifer	No demonstrated natural resource in NSW
Biomass Gasification	Same fuel as cheaper Biomass Combustion
Biomass Methane	Very small resource
Fluidised Bed Coal Combustion	No advantage over pulverised fuel for NSW coal
Pressurised Fluidised Bed Coal Combustion	No advantage over pulverised fuel for NSW coal except easier to burn a wider range of fuels.

Source: Connell Wagner, Expert Report 1, pp. 10, 34-35.

1 *Environmental emissions from energy technology systems: the total fuel cycle*, Proceedings of IEA/OECD Expert Seminar, Paris, 12-14 April 1989

Hydro

Hydro generation is a significant contributor to meeting NSW peak demand and some intermediate energy needs. New South Wales sources around 4,000GWh of energy each year from the Snowy region and from NSW hydro generators. However the potential for hydro to provide future baseload energy is very limited as there is little water for power generation and limited dam sites for future development.

Pumped storage hydro can meet peaking demand but is carbon intensive as it requires baseload generation to supply the pumps, not all of which is recovered.

Connell Wagner noted that, according to the Redding Energy Report,[2] only around 50MW of additional capacity and 275GWh of additional hydro energy was available to New South Wales, with some of this additional capacity having been installed since the Report was prepared.

Due to their size (less than 30MW each), the projects listed in the Redding Report would most likely be classed as non-scheduled generation.

There is currently around 3,700MW of hydro generation in Snowy, another 350MW of scheduled hydro generation in New South Wales and a number of existing small non-scheduled units.

Table 3.2 summarises the technical characteristics of hydro generation, and the costs of additional plant based on the Redding Report. The cost range covers all projects identified, and the higher cost projects may not be financially viable.

Table 3.2: Hydro Generation - Technical Characteristics and Cost

Technical Maturity	$CO_{2\text{-}e}$ Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Mature	4-10	See next paragraph	1.5-3.7	27-282	Depends on water availability	Very high

[2] *2 per cent Renewables Target in Power Supplies – Potential for Australian Capacity to expand to meet the target,* Redding Energy Management in association with RMIT Energy and Environmental Management Group, January 1999.

The main issue related to hydro projects is the potential impact on the environment from retaining stream flows behind dams and changing stream flows below the dams. New dams also result in flooding of existing environments and can release methane from remaining vegetation for some years following inundation.

Wind

Wind power is a mature renewable technology with over 74,000MW of capacity operating worldwide. Australia has about 800MW of installed operating capacity, with around another 700MW under construction. The vast majority of this capacity is installed in Victoria, South Australia and Tasmania, which appear to have better wind characteristics for power generation.

New South Wales has 17MW of wind capacity installed and operating, however a NSW based wind farm developer has provided information to the Inquiry on a pipeline of projects located in New South Wales.[3]

Wind generators are more expensive to build than some other types of generators, and are not generally commercially viable without incentives such as mandatory renewable energy targets. On a $/MWh basis, the cost of generation from wind generators is more than twice the cost of generation from coal-fired baseload plants.[4]

The output from wind generators is not always available. Rather, the output is dependent on wind strength[5] and as a result, only a small portion of their capacity can be relied on with certainty for meeting peak demand. Having a portfolio of generators at different sites provides diversity and reduces the overall output variability, but significant back up capacity is still required for reliable supply.[6] Wind turbines typically operate at an annual capacity factor of around 30 per cent in New South Wales. Only 5 to-10 per cent of total installed wind turbine capacity can be considered firm during peak periods in New South Wales.

When wind generators are running they displace energy which would otherwise be generated by burning coal. In this sense, they can be seen as contributing to baseload generation. But because wind is not reliable new wind generators will not replace a need to invest in gas or coal-fired generation plant.

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3 Epuron presentation to Owen Inquiry, August 2007

4 Based on capacity factors and capital costs

5 See for example the power curves in the Vestas brochures at http://www.vestas.com/vestas/global/en/Products/Wind_turbines/Wind_turbines.htm

6 See NEMMCO's 2006 SOO, section 3.6.6 for further discussion

Table 3.3 summarises the technical characteristics and costs of wind generation.

Table 3.3: Wind Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Mature	7	Nil	1.8-2.5	75-90	~30%	High when wind available

The major environmental issues for wind developments are visual amenity and noise. In some cases, the impact on birds is also relevant. Some projects have been contentious.

Noise impacts may be managed through appropriate setbacks and blade design. Visually a new 3MW unit has a hub height of 80-105 meters and a 90 metre rotor diameter[7], giving a maximum blade tip height of 125-150 metres. By comparison, the summit of the Sydney Harbour Bridge's arch is 134 metres above sea level.

At a 30 per cent capacity factor in New South Wales, each 3MW turbine will produce around 8GWh of energy per annum. Around 600 such turbines would be required to provide the same energy as one existing 660MW coal-fired turbine operating at an 80 per cent capacity factor.

Land use is generally less of an issue with wind as multiple land uses are usually possible involving some agriculture as well as power generation.

Solid Biomass

The term solid biomass covers different types of organic energy resources, including forestry and agricultural wastes and residues, urban tree trimmings, food processing wastes, woody weeds, oil bearing plants, animal manures, sewage and energy crops.

Biomass is generally burnt in conventional, low stress boiler designs consistent with high moisture content fuels. As this technology is well established, reliability is likely to be high.

According to the NSW Bio-energy Handbook,[8] there is the potential for approximately 1,600MW of Biomass Thermal generation in New South Wales. Solid biomass material such as forestry and agricultural waste can be a viable fuel for power generation provided that the fuel does not have to be transported long distances or stored under cover.

[7] Vestas Product Brochure for a Vestas V90 3MW unit

[8] Rutovitz, Jay; Passey, Robert, *NSW Bio-Energy Handbook*, Department of Energy, Utilities and Sustainability, 2004

To date, biomass plants have been most successful where biomass is derived from another production process. In this scenario, the fuel is already collected and further transport is not required for conversion to electrical energy.

It is difficult to quantify how much of this 1,600MW potential can be successfully and cost-effectively used.[9] Connell Wagner note that there is currently only 92MW of biomass generation developed in New South Wales. Additional biomass generation may only become cost-effective if the cost of production falls or the electricity price rises.

Table 3.4 summarises the technical and cost characteristics of biomass generation.

Large scale development of biomass would incur considerable costs for fuel aggregation and transport and storage to enable baseload generation throughout the year. Such costs limit the financial viability of projects unless substantial incentive payments are available.

Table 3.4: Solid Biomass Generation, Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Mature	Possibly negative under some circumstances	~2,000 (wet) ~ 150 (dry)	~2.5	47-120	Varies (can be seasonal)	High

Environmental impacts include air emissions from biomass plants including particulates and NOx, similar to other thermal combustion processes. Like other thermal processes using steam turbines, the working fluid must be cooled and condensed and this requires water for cooling unless dry cooling is used.

Solar Thermal

The solar thermal energy concept uses heat generated from solar radiation, typically concentrated using reflectors, to provide the temperatures necessary to transfer the solar energy to a working fluid (e.g. water) or a heat engine. Reflectors vary substantially in design, and include parabolic troughs, compact linear Fresnel collectors (shallow troughs), solar towers and parabolic dishes.

[9] For an indication of the many issues that need to be assessed for each bioenergy project, see the Australian Government's *"Sustainability Guide for Bioenergy – a scoping study – December 2005"*

Solar thermal technology can be used on a stand alone basis, or in conjunction with thermal steam fired stations, where solar energy can substitute for energy from fossil fuel, or, if there is adequate spare capacity in the generator and steam turbine, can contribute to providing additional energy and capacity beyond the boiler rating.

Solar thermal technology is still at the demonstration stage and further research is required to make it cost-effective. A 64MW plant (the first large solar thermal plant in 16 years) was commissioned in Nevada in 2007. This plant is expected to produce 134GWh of energy per annum. The largest plant in the world is the 354MW Solar Energy Generation Systems plant in the USA, which was commissioned over 15 years ago. For solar thermal to be suitable for baseload more research will be required to be a cost-effective solution for energy storage.

In partnership with Solar Heat and Power, Macquarie Generation is building Australia's largest solar project at Liddell Power Station. This will be the first time in the world that solar technology is integrated with a coal-fired power station. The original pilot mirror array is being expanded to cover an area of 20,000 square metres or approximately four football fields, with over 800 mirror panels, each 12 metres by 2 metres. This will reduce CO_2 emissions by about 4000 tonnes per annum.

Table 3.5 summarises the technical characteristics of solar thermal generation, and indicative costs of new plant.

Table 3.5: Solar Thermal Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Demonstration	~3	~2,000(wet) ~ 150(dry)	~3	~120-150	25 (without storage)	High in areas with reliable insolation

As with all thermal technologies, solar thermal requires water for the steam cycle and for cooling. For baseload, land use is also a consideration as a reflector area of around 7km by 7km (plus a buffer and turbine) is required to produce the energy equivalent to that of a 660MW coal-fired turbine.[10]

[10] Connell Wagner Expert Report 1, p.43

Geothermal Hot Dry Rock

Hot Dry Rock (HDR) energy extracts heat from underground rocks and converts that energy into electricity in a power station located on the surface. The power plant is similar to conventional steam driven power plants.

To access the heat, wells are drilled in to the target rocks about two to five kilometres below ground. Hydraulic fracturing of the hot rock is used to connect the injection and production wells.

Theoretically, HDR geothermal generation could provide sufficient energy to produce large amounts of electricity at high capacity factors for many years.

The actual performance of a large scale power plant using HDR energy is not proven as no projects have yet been constructed, even to the demonstration stage in their entirety in Australia or elsewhere. However, Connell Wagner notes that many of the components that would make up such a plant are available.

Connell Wagner noted that plans are underway to develop a small HDR power plant at Soultz-sous-Forêts in France, and near Moomba in South Australia. The Moomba development is being undertaken by Geodynamics, who plan to have 50MW of capacity delivered to the NEM in 2010.

Geodynamics' submission states that Geodynamics expects to be able to provide 500MW of baseload to the NEM by 2015-16. This is encouraging, but given that no station has yet been built anywhere in the world, the Inquiry does not consider this technology is sufficiently developed to be relied on at this stage.

Sites suitable for HDR are not necessarily close to consumers or transmission infrastructure, and new transmission would either need to be funded by the proponent, or would need to pass the regulatory test in the National Electricity Law (NEL).

The market signals from the NEM and from emissions trading, coupled with the regulatory tests for transmission augmentation contained in the NEL, should provide an environment where this technology could be delivered if it is demonstrated to be both technically and commercially viable.

Table 3.6 summarises the technical characteristics of geothermal hot rock generation, and the cost characteristics of new plant.

Table 3.6: Geothermal Hot Rock Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Research	~2	High	High	Various estimates ranging from comparable with coal-fired plant to very high	Potentially High	Unknown

Geodynamics in their submission to the Inquiry noted that total costs of HDR generation approaching coal-fired plant should be achievable[11].

The major environmental issue for HDR plants is water use. Enough water must be available for cooling and the steam cycle, and in addition, sufficient water is needed to make up for losses in the reservoir. These losses are dependent on the geology of the resource.

Nuclear

Nuclear power generation involves utilising the heat from a controlled nuclear fission reaction. Intermediate sized atoms have the lowest energy and nuclear fission involves splitting large atoms to form smaller atoms of lower energy. Conversely, nuclear fusion involves joining small atoms to form larger atoms of lower energy.

The heat from nuclear fission is used to drive a sub-critical steam turbine in a similar manner to existing coal-fired generators in New South Wales.

There are a large number of different designs of nuclear reactors available. Variables include the fuel used and produced within the reactor (natural uranium, enriched uranium, breeder reactors), whether the reactor is driven directly from the water flowing through the core (boiling water reactor) or through water heated via a heat exchanger (pressurised water reactor, gas cooled reactor), the medium used for the moderator (graphite, water, heavy water), and a host of other factors.

The most common designs are pressurised water reactors that use water as a moderator.

[11] Geodynamics submission, p2

Nuclear power is an established and proven technology and has been in use since the 1950s. Nuclear power generation supplied around 16 per cent of the world's electrical energy in 2005.

Table 3.7 summarises the technical characteristics of nuclear generation, and the costs of new plant.

Table 3.7: Nuclear Generation - Technical Characteristics and Costs

Technical Maturity	$CO_{2\text{-}e}$ Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Mature	~3	1,100 to 1,850 (wet)	2.9	50-80 (first plant)[12]	90	High

Cooling water requirements are a significant factor in siting nuclear plants as the thermal efficiency is low and a much larger cooling system is required than for an equivalent sized coal-fired plant. This tends to favour coastal sites which are likely to be contentious. The alternative is to use wet cooling towers which would consume a large amount of scarce water resources. Given the size of the heat load dry cooling on a nuclear plant could be prohibitively expensive.[13]

Radioactive waste and spent fuel are by-products of nuclear generation, and disposal remains a major issue. Connell Wagner noted that whilst there is scientific and technical consensus that high level waste may be stored underground in stable geological structures, no country has yet implemented permanent underground disposal.

Nuclear generation also has security implications, both in management of the fuel cycle and in protection of the generation facility. Additional security measures, if required, will necessarily result in additional costs.

In his speech to the NSW Parliament on 9 May 2007, the Premier stated 'there will be no consideration of nuclear energy for NSW whatsoever'. Furthermore it is relevant that the time for establishing a nuclear energy regulatory framework and planning, building and commissioning a nuclear power plant in Australia is expected to be at least 10 to 20 years, so nuclear energy is not an option for the next NSW baseload plant.

[12] Connell Wagner estimate settled cost at $44-$70/MWh but suggest that these costs are likely to be 10-15 per cent higher for the first Australian plant.

[13] Alstom Submission, p21.

Coal-fired technology

Coal-fired generation is a mature though still evolving technology. It provides much of the world's baseload power and in Australia provides 85 per cent[14] of total energy supply. The NSW power system is dominated by coal-fired generation which reflects the availability and cost of black coal.

Ultra-supercritical (USC) Pulverised Coal Fuel

Sub-critical coal-fired pulverised fuel boiler turbine units provide the vast majority of existing NSW electrical energy needs and have been the mainstay of generation in New South Wales for decades, with over 11,000MW of such coal-fired capacity installed and operational.

With the benefit of improved materials technology, it is now possible to have higher steam cycle pressures and temperatures up to and beyond the critical steam condition point where liquid and vapour co-exist in equilibrium. The changeover point between supercritical and ultra-supercritical is arbitrary, but the sub-critical to supercritical changeover is defined by the physical characteristics of the steam. However it is now generally accepted that steam conditions above 26 MPa pressure and 580-600°C are termed ultra-supercritical.

There is vast international and domestic experience in high pressure technologies, with over 17,000MW of supercritical and ultra-supercritical plant built throughout the world in the last 15 years, with capacities ranging from 385MW to 1050MW.

Ultra-supercritical coal-fired power stations are able to run at high efficiency and capacity factors and generate large amounts of electricity. In the absence of an emissions trading scheme, they are the cheapest method of generating baseload electricity in New South Wales.

Table 3.8 summarises the technical characteristics of ultra-supercritical pulverised fuel coal generation, and the costs of new plant.

[14] Australian Coal Association

Table 3.8: Ultra-supercritical Pulverised Fuel Coal Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Mature	785 - 820	1800 - 1900 (wet) 130 - 140 (dry)	1.4-2.0	~35	~90	High

A key issue for this technology is carbon emissions. As shown in the above table, new coal-fired generation has a carbon intensity of 785 to 820 kg of CO_2 per MWh, compared to a current NEM pool intensity of around 1,000 kg of CO_2 per MWh.

New coal-fired generation would displace less efficient and more carbon intensive coal-fired generation in the merit order of dispatch and so would reduce the average carbon intensity in the NEM. However, this technology is more carbon intensive than gas-fired or renewable generation.

Other emissions, such as particulates, nitrogen oxides (NOx) and sulphur oxides (SOx) are associated with the coal combustion process. Pollution control measures are incorporated in such plants to ensure the appropriate licence conditions are met. In addition, New South Wales benefits from low sulphur coal.

Water requirements are an issue for coal-fired stations. Higher efficiencies are obtained where wet cooling is used, but dry cooling is available where water is scarce. Hybrid schemes have also been proposed with the aim of maximising efficiency when water is available. Coastal sites are obviously valuable as they enable wet cooling.

Carbon capture is not currently available for any mature generation technology at utility scale. For USC, Post Combustion Capture (PCC) would be required and the principles underlying this technology are well understood. In addition manufacturers are able to make USC generators PCC-ready by making provision in their designs for the carbon capture plant that will be required if PCC is to be retrofitted in future.

Integrated Gasification Combined Cycle (IGCC)

IGCC is an advanced power generation technology that has been developed in an attempt to achieve higher thermal efficiencies and lower carbon emissions than conventional coal based thermal power generation technologies.

The IGCC process converts coal to carbon monoxide and hydrogen in a gasifier, which is then fed in to a gas turbine and burnt. As with combined cycle gas turbines, the exhaust from the gas turbine is fed in to a boiler, which in turn generates steam to produce additional electricity.

All of the plant and sub-processes used in an IGCC facility are commercially available and currently used in the petroleum, chemical and power industries. However, there are only four IGCC plants in the world that use similar coal to that available in New South Wales. These four plants were commissioned between 1994 and 1997 as demonstration plants and range in size from 280MW to 320MW. The technology is therefore available now, but the system maturity is significantly lower than ultra-supercritical pulverised fuel technology, and economies of scale have not been realised.

Thermal efficiency is similar to that obtained from USC technology. Experience to date is for availabilities of 80 per cent or less, mainly due to the complex nature of the plant, although it is expected that future availabilities of 85 per cent could be achievable. This compares to around 90 per cent availability for ultra-supercritical pulverised fuel plants. Although IGCC technology is less mature than USC technology and therefore currently poses a technology risk, IGCC potentially has some advantages when configured for carbon capture. At this stage there is no IGCC demonstration plant with carbon capture. Connell Wagner is of the view that this technology is a possible contributor to NSW baseload for plant in operation after 2020 and accordingly this technology needs to be kept under review.

The technical characteristics of IGCC coal-fired generation and the costs of new plant are summarised in Table 3.9.

Table 3.9: Integrated Gasification Combined Cycle Coal Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Demonstration	~785-820 (wet)	1750-2250 (wet) 225 (dry)	2.1-2.6	~50 (no carbon capture)	~85 (future)	Moderate (future)

IGCC uses significantly more water than conventional coal-fired plants, making it more likely that dry cooling will be required, which reduces efficiency.

Carbon dioxide emissions are similar to supercritical pulverised fuel coal plants.

In IGCC, NOx and SOx precursors are cleaned from the syngas prior to entry in to the combustion turbine, so the NOx and SOx emissions are extremely low. Particulate emissions are also low.

Retrofitting of carbon capture should be easier on an IGCC plant than on a conventional ultra-supercritical plant because of the lower level of pollutants and higher proportion of CO_2 in the syngas and because of higher operating pressures.

Future developments may allow for the use of shift reactors to remove a continuous stream of carbon dioxide prior to the combustion of hydrogen. However, hydrogen turbines are not yet available, and retrofit of this form of carbon capture is not possible without replacing the turbine itself.

Ultra Clean Coal Gas Turbine Combined Cycle

This technology uses of a coal derived fuel (ultra clean coal) in a gas turbine combined cycle plant. Ultra clean coal is produced from a thermal coal feedstock that is treated through a chemical process to remove mineral matter and alkalis. Ultra clean coal is fed as a fuel directly in to a gas turbine.

The technology is being developed by UCC Energy, a wholly owned R&D subsidiary of White Mining Limited in conjunction with CSIRO and is supported by both the NSW and Federal Governments.

As this technology is still at the demonstration stage it is not yet suitable for providing the next tranche of baseload energy to New South Wales.

It is understood that purpose built gas turbines may be required to allow utilisation of UCC. Combustion trials on a Mitsubishi Heavy Industries machine in Japan were considered successful as performance was satisfactory and no blade erosion was detected. However, blade ash deposits and high combustion temperatures were of concern. A further demonstration with an 18 month trial on a 6 - 15MW gas turbine is planned for 2008.

Table 3.10 summarises the technical characteristics of UCC generation, and the costs of new plant.

Table 3.10: Ultra Clean Coal Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Demonstration	635 for power station only 770 – 825 including UCC production	Unknown	Unknown	Unknown. Fuel cost is expected to be in the range $2.70 - $3.30/GJ	Unknown	Unknown until full scale demonstration is conducted

The ability to capture carbon is unknown, but is likely to be similar to combined cycle gas turbines.

Gas-fired technology

Combined Cycle Gas Turbines

Two types of gas-fired generators are currently in widespread use and available for generation in New South Wales. These are open cycle gas turbines and combined cycle gas turbines.

With open cycle gas turbines the exhaust gases after combustion are discharged to atmosphere via a stack, and the turbine directly drives an electrical generator.

Combined cycle gas turbines (CCGTs) use a gas turbine similar (and in some cases identical) to the ones used for open cycle gas turbines, but also use the exhaust gas to raise steam in a boiler, which is then used to drive a steam turbine and generator. This increases the efficiency of the gas turbine at the cost of additional capital.

Gas turbines are a mature technology, with tens of thousands of megawatts of capacity installed worldwide.

CCGTs are capable of running efficiently at high capacity factors. They are significantly cheaper to build than coal-fired generators, but have higher fuel costs, and it is this that most restricts their attractiveness for baseload power.

However, due to this cost structure, CCGT technology is amongst the most attractive for new intermediate plant, and TRUenergy has already invested in a 400MW unit in New South Wales at the Tallawarra site south of Wollongong.

Table 3.11 summarises the technical characteristics of CCGT gas generation, and the costs of new plant.

Table 3.11: Combined Cycle Gas Turbine Gas Generation - Technical Characteristics and Costs

Technical Maturity	CO_{2-e} Intensity (kg/MWh)	Water Use (l/MWh)	Capital Cost ($m/MW)	Total Cost ($/MWh)	Capacity Factor NSW (%)	Reliability
Mature	~350	1,000 (wet) 20 (dry)	0.8-0.95	45-55 (depending on capacity factor at current gas prices	70-90	High

CCGTs have less than half of the carbon emissions of new coal-fired power stations, and will therefore benefit relative to coal when an emissions trading scheme is introduced. With a high enough CO_2 price, combined cycle gas turbines could potentially provide lower cost baseload than coal-fired generation on the assumption that gas prices do not increase significantly above current levels.

3.3 Carbon Capture and Storage

Carbon capture and storage (CCS) has the potential to significantly reduce the emission of CO_2 from fossil-fuel fired baseload generators. Carbon capture and storage is a process of:

- separating of CO_2 from industrial and energy related sources (carbon capture)
- transporting of CO_2 to a storage location
- long term isolation of CO_2 from the atmosphere (carbon storage).

Whilst the Inquiry cannot recommend any specific carbon capture and storage solution at this time, CCS is an important technology option to enable fossil fuels to be used sustainably in the future. Consequently, the Inquiry has investigated options for carbon capture and storage to ensure that the necessary steps are being taken so New South Wales can move to CCS when the technology is ready.

Carbon capture technology

Connell Wagner identified three generic CO_2 capture technologies. [15] The technologies are at differing levels of maturity. Some are being used in other industries (e.g. manufacture of fertiliser) however none are currently being used commercially in electricity power stations. For detailed information see the Connell Wagner Report provided as Expert Report 1.

[15] Connell Wagner, Expert Report 1, Appendix 3.1

The carbon capture technologies reviewed by Connell Wagner and their findings on suitability for application in NSW for baseload generation are set out in Table 3.12.

Table 3.12: Summary of Carbon Capture Technology Assessment

Capture Type	Technology	Status of Development	Suitability for next investment in baseload in NSW
Post Combustion	Chemical absorption – amine	Commercial (small scale installations)	No – insufficiently mature
	Chemical absorption – chilled ammonia	Demonstration	No – still at demonstration stage
	Membrane separation	Commercial	No – insufficiently mature
	Solid sorbent	Laboratory	No – still at research phase
	Cryogenic	Commercial	Not yet demonstrated at utility scale and has high energy demand.
Oxy-Fuel Combustion		Demonstration	No – but to be reviewed post demonstration
Pre-Combustion (for IGCC technology only and not for pulverised coal generators)	Physical absorption – Selexol	Commercial	No – depends on when IGCC is considered mature
	Physical absorption - Rectisol	Commercial	No – depends on when IGCC is considered mature

Source: Connell Wagner, Expert Report 1, Appendix 3.1

It is important to note that CCS technology is estimated to require up to 30 per cent of the energy generated to be used by the power station and carbon capture process. This compares with a figure of 5 per cent for a power station without CCS

The oxy-fuel combustion option is to be demonstrated at Callide A power station in Queensland. Connell Wagner recommended a review of this technology following this demonstration.

The only carbon capture technology that Connell Wagner identified as being sufficiently mature at this time for application at power utility scale is the physical absorption technologies, using either Selexol or Rectisol. However, these technologies are potentially only suitable for use with Integrated Gasification Combined Cycle technology (IGCC) and no IGCC demonstration plant with carbon capture has yet operated. Connell Wagner also found that IGCC is not likely to be suitable for baseload operation in New South Wales until after 2020.

The Inquiry considers that carbon capture technology is not sufficiently mature to be used in New South Wales for any upcoming investment in baseload generation but needs to be kept under review. Notwithstanding this ongoing research and development on CCS should be supported to enable fossil fuels to be used sustainably in the medium term. In addition, any new coal-fired generation should be built to provide for retrofitting of carbon capture plant to enable CCS at such time that the technology becomes commercially available.

Carbon transport

Once separated from other gases and compressed, CO_2 can be transported by pipeline, road, ship or rail. In practice because of the huge volume of CO_2 involved only pipelines and ships are cost-effective options.

Pipeline transport of CO_2 is well understood. For example in the US there are several thousand kilometres of pipelines used to transport CO_2 for use in enhanced oil recovery. In Australia, transport by pipeline is accepted, and widely used for natural gas.

Transport by road or rail may be technically feasible for small scale projects but is likely to be prohibitively expensive. Transport by ship may also be feasible in the same way Liquefied Natural Gas (LNG) is transported around the world.

Transport costs by pipeline are likely to be reasonable given the large quantities of CO_2 involved.[16]

Carbon storage solutions

Connell Wagner was also asked to review carbon storage solutions that would allow for the long term isolation of carbon. Connell Wagner reviewed three approaches:

- geological storage of CO_2 in deep geological formations either onshore or offshore
- deep ocean storage
- the reaction of CO_2 with metal oxides, so as to convert the CO_2 into a mineral.

[16] Connell Wagner Expert Report 1, Appendix 3.1.

Geological storage

There are at least five options for the geological storage of CO_2, these are:

- depleted oil and gas reservoirs
- enhanced oil recovery
- deep saline formations
- deep unminable coal beds
- enhanced coal bed methane recovery.

The different options are at varying stages of technological maturity. However there are three industrial scale storage projects in operation in the world. Connell Wagner report that by 2008 it is expected that these three projects will be storing a total of 25 million tonnes of CO_2 per annum. By way of comparison, in 2004, Australia's total greenhouse gas emissions were approximately 565 million tonnes of CO_2-e, of which about 35 per cent was from the electricity generation sector (about 198 million tonnes CO_2-e)[17].

Ocean storage

Theoretical options for ocean storage of CO_2 include:

- a CO_2 lake at the bottom of the ocean via a pipeline (at ocean depths CO_2 is a liquid and denser than water)
- dispersing CO_2 from a ship to a lake via pipeline or dispersing it in the ocean
- water column release at a depth of 1000m or greater for dispersal.

There is no experience of applying any of these options and the environmental risks are unknown.

Stable carbonate conversion

Connell Wagner reported that CO_2 can be converted to stable carbonates using alkaline metal oxides such as magnesium oxide and calcium oxide. Mineral carbonation produces carbonates that are stable over long time scales and can therefore be disposed of in areas such as silicate mines or re-used for construction purposes.

The carbonisation process is still at research phase.

[17] NETT Discussion Paper, *Possible Design for a National Greenhouse Gas Emissions Trading Scheme*, August 2006, Chapter 2.

Options for carbon storage in New South Wales

The NSW Government is actively supporting research into options for the storage of CO_2 in deep underground storage basins.

Recent studies undertaken by the Department of Primary Industries along with the NSW State Owned Generators have identified significant potential for storage of CO_2 in underground reservoirs. In particular, the Darling Basin in central New South Wales is a potential site for large scale storage of CO_2 into saline aquifers. There may also be potential within the Sydney Basin as well as a number of sedimentary basins in New South Wales. However, further geological studies will need to be undertaken to fully characterise this potential. These studies are expected to take up to five years to define sites suitable for pilot or demonstration projects.

A recent report prepared by the House of Representatives Standing Committee on Science and Innovation[18] recommended the Australian Government provide funding to the CSIRO CO_2CRC to assess the storage potential for permanent CO_2 sequestration in sedimentary basins of New South Wales, and the economic viability of these sites. CO_2CRC is now working with the NSW Government to undertake a comprehensive and definitive assessment for storage potential in New South Wales.

Potential carbon storage sites are discussed further at Appendix 3.1.

3.4 Fuel Availability and Cost

Coal[19]

New South Wales has ample coal resources, with estimated recoverable reserves of around 10 billion tonnes. This includes coal resources from current operations and from short, medium and long term development proposals. In 2004-05, the NSW coal industry produced 156 million tonnes of raw coal. Existing NSW power stations consume around 30 million tonnes of coal per annum.

These coal resources are available to be utilized for domestic electricity generation, in addition to being suitable for export steaming and coking purposes.

[18] *Between a Rock and a Hard Place, Report on Geosequestration Technology*, House of Representatives Standing Committee on Science and Innovation, 13 August 2007.

[19] Except as noted, data in this section are a subset of the data contained in the 2006 *New South Wales Coal Industry Profile*, published by the NSW Department of Primary Industries.

The Hunter, Newcastle, Western and Gunnedah coalfields contain some coal that is suitable for export markets and some coal that is suitable for domestic markets. The export quality coal includes coal that is used in steelmaking (coking coal) and for the production of electricity (thermal coal). Export coking coal typically contains less than 10 per cent ash and export thermal coal typically contains less than 15 per cent ash in the product.

The coal consumed in NSW power stations generally lies within a range of 18 per cent to 26 per cent ash or even higher in some cases. This coal is not generally suitable for export.

Approximately 30 per cent of the total coal resource is available for domestic electricity generation, primarily due to the quality of coal that is present in the coal resources in the Hunter, Newcastle, Western and Gunnedah coalfields.

Connell Wagner used fuel costs from the ACIL Tasman report prepared for NEMMCO[20]. The report states that the projected real weighted average coal prices delivered into NSW power stations (in 2007-08 prices) is $1.36/GJ in 2007-08 decreasing to $1.26/GJ in 2026-27.

A real weighted average coal price of $1.36/GJ for 2007-08, with a typical 22 per cent ash coal delivered to the power stations (with around 23 MJ/kg of energy), equates to around $10/MWh of electricity generated.

Based on the submissions received by the Inquiry, these coal prices may be high. Macquarie Generation's submission suggests a fuel cost of around $0.90/GJ delivered for domestic coal supplied to a new development may be achievable[21].

Gas

Reserve adequacy

Publicly available reports[22,23] reviewed by to the Inquiry indicated that there could be significant limitations on the gas available within the eastern seaboard to support baseload generation growth over the next ten years. However, a number of stakeholders indicated that they believed that larger gas quantities were available.

[20] ,ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, Report 2 – Data and documentation, Draft prepared for NEMMCO, 27 March 2007

[21] Macquarie Generation Submission, p19

[22] ACIL Tasman, *Fuel resource, new entry and generation costs in the NEM*, Report 2 – Data and documentation, Draft prepared for NEMMCO, 27 March 2007, p86.

[23] ABARE research report 06.26, *Australian energy national and state projections to 2029-30*, December 2006, p5.

To resolve this, the Inquiry engaged Wood Mackenzie to examine the adequacy of gas resources and infrastructure to support baseload generation in New South Wales and in the NEM. The Wood Mackenzie Report is provided as Expert Report 2.

Wood Mackenzie assessed the availability of gas reserves and infrastructure for four indicative gas-fired scenarios. The scenarios which were based on the investment pathways similar to the market development scenario developed by NEMMCO[24] are:

- a development pathway with commissioning of coal-fired and gas-fired generation as set out in Table H8 of the 2006 SOO out to 2015-16
- a 'high' case, with all new NEM generation provided by gas.
- two intermediate cases, with:
  - all new NSW generation provided by gas
  - all but 1000MW of new NSW generation provided by gas.

Wood Mackenzie concluded that, whilst production from existing Proven plus Probable (2P) reserves will begin to decline from around 2012-2014, the development of additional potential from identified Possible (3P) reserves is likely to see gas production rates in Eastern Australia that are adequate to support the high gas case demand out to around 2020.

Wood Mackenzie also noted that their forecasts did not take in to account any yet-to-find resources, but that further exploration is continuing in the Otway, Bass and Gippsland basins. Additional discoveries are considered likely to add to the gas supplies available.

Further, Wood Mackenzie noted that other potential is available in the "tight" gas resources in the Cooper and Gippsland basins, which could become economic to develop if gas prices rise.

Under the high case, after 2020 additional gas will be required to support existing consumption and additional growth. This gas will be sourced either from new Eastern Australian discoveries, existing "tight" resources that are not yet economic, or from long distance gas pipelines or LNG. However, long distance gas and LNG are likely to move Eastern Australian gas prices closer to international parity, whilst extraction of "tight" resources locally will be more costly and will therefore require higher gas prices.

[24] NEMMCO, Statement of Opportunities, 2006, Appendix H, Table H8.

Proven and Probable (2P) gas reserves in New South Wales are currently limited. However there is significant potential for Coal Seam Gas (CSG) in a number of basins with much of the area already covered by exploration licenses. Success with CSG in Queensland is further stimulating interest in New South Wales.

In some cases small scale commercial development is imminent or in early stages of production including small-scale baseload generation. Whilst some of these developments have potential to make a significant contribution to gas supplies in the longer term, it is unlikely that they could make a major contribution to baseload gas-fired generation in the near term.

An important issue for CSG in NSW will be access to pipeline infrastructure with the opportunity for new pipelines from Queensland to follow routes which can serve CSG operations in NSW.

Gas transmission pipeline adequacy

Wood Mackenzie has examined existing pipeline capacities and has estimated the timing of new pipelines and augmentations. Wood Mackenzie's development scenario includes the following estimated development dates:

- Ballera to Moomba Interconnect – 2009 (recently announced by AGL for commissioning in December 2008[25])
- Queensland to Hunter Pipeline – 2013
- Wallumbilla to Bulla Park pipeline – 2014.

The potential to expand the capacity of the Eastern Gas Pipeline by compression in around 2013 is also noted by Wood Mackenzie.

With the above upgrades, Wood Mackenzie estimates that there will be adequate gas transmission capacity to support the following gas baseload generation in New South Wales over and above existing committed generation:

- Two 400MW CCGT baseload developments on the Eastern Gas Pipeline
- Two 400MW CCGT baseload developments on the Moomba – Sydney Gas Pipeline
- Two 400MW CCGT baseload developments on the Queensland – Hunter Gas Pipeline.

[25] **AGL media release,** AGL *secures pipeline deal to link its gas to eastern markets*, 13 July 2007.

Gas pricing

Eastern Australian gas is currently available at around $4 per GJ, which equates to around $25 per MWh of electricity generated. Whilst this more expensive on a per MWh basis than coal (at around $10/MWh), the much higher capital cost of coal plant means that gas-fired CCGT generators have a lower total average cost than coal at below around 50 per cent utilisation.

However, there is a significant degree of uncertainty around gas prices. The Australian eastern seaboard benefits from having enough gas for domestic consumption, but no export industry. The market is therefore self-contained, and not subject to international competition. This has resulted in Eastern Australia historically having gas prices that are significantly lower than the international gas price. However, as demand increases prices may rise.

Forecast delivered gas prices under the scenarios studied by Wood Mackenzie show a wide band ranging from only modest increases above current levels over time with no new baseload gas-fired generation, to around $6.50/GJ (with new gas-fired baseload generation operating at a 75 per cent load factor) at the upper scenario bound. These prices include the delivery (commodity and transportation) charges.

Further, the eastern States could face gas prices rising up to a netback price referenced to LNG export parity prices if domestic gas sales are competing with export gas sales. This could be brought about if local gas supplies require augmentation from jurisdictions that also export LNG, such as Western Australia, or if Eastern Australian gas is exported, as is currently proposed by Santos[26].

In the absence of international competition, gas prices will be determined by local conditions, including the carbon price.

The gas price should however be capped by the coal price (adjusted to allow for the carbon price and differences in capital and operating costs of power stations). This is because a proponent will invest in the type of generation that delivers electricity at the lowest cost. If gas becomes too expensive, proponents will invest in coal-fired generators. This will reduce forecast gas demand, which will in turn lead to lower forecast gas prices.

[26] Santos media release, *Santos proposes multi-billion dollar Gladstone LNG Project*, 18 Jul 2007

The price movement would be more rapid if the gas market was not fully competitive, as in these circumstances gas suppliers would be able to increase gas prices until they approached the adjusted coal price, without significantly impacting gas demand.

Gas reliability

Wood Mackenzie has identified a number of single contingency events that could lead to temporary gas shortfalls. These include:

- a major offshore platform issue
- a processing plant incident
- a pipeline failure.

Whilst these events have low probabilities, they can reduce supplies for an extended period and may have significant security of electricity supply implications if a substantial portion of NSW generation were to be gas fuelled.

The impact of these high consequence events in the gas market may be mitigated in the electricity market. The storage capacity (line pack) on gas pipelines can act as a buffer in the event, for example, of a processing plant failure and for a modest additional cost gas generators can be designed to run on either gas or distillate, providing an alternative back up fuel supply.

It is desirable to mitigate the risks of loss of gas supply to the extent that it is economic to do so – that is, where the cost of mitigation is less than or equal to the benefit obtained.

The NEM achieves this by providing strong incentives for generation adequacy for electricity supply through the market ceiling price (Value of Lost Load – VoLL). VoLL is set at a level that ensures that nominated reliability standards are maintained. The AEMC Reliability Panel recently completed a 2007 review of VoLL under the National Electricity Rules and recommended retaining the market price ceiling at $10,000 per MWh.

In New South Wales, there is no equivalent VoLL mechanism for gas. Rather, the financial consequence of a gas interruption to the supplier is a matter of contract.

Whilst it could be argued that this allows individual customers to negotiate appropriate arrangements with suppliers, it seems unlikely that multiple network owners and literally millions of gas customers would be able to successfully join together to negotiate optimal supply arrangements.

Emergency powers are available and are occasionally used to appropriately allocate gas to address shortfalls. However, a market arrangement that recognises the cost to customers of being without supply is possibly a better outcome as it is transparent, and encourages appropriate short, medium and long term actions.

Market signals are becoming more transparent in New South Wales with the development of bulletin boards for the gas balancing market by the Ministerial Council on Energy (MCE) as a step towards a gas spot market similar to electricity, and with the COAG decision for a single energy market operator. These reforms should further enhance the ability of the market to send appropriate price signals.

The evolution of the eastern gas market over time, and the further evolution of the gas market framework through the MCE process should see improved market signals, leading to appropriate gas investment outcomes.

Wood Mackenzie's report also foreshadowed changes to the function of gas transmission pipelines. Traditionally, transmission pipelines have largely been connection assets linking particular gas fields with particular loads or load centres. However, over time they are moving to being network assets connecting gas regions.

For example, the proposed Queensland to Hunter pipeline runs in parallel to the proposed Ballera to Moomba pipeline, which itself is parallel to the proposed Wallumbilla to Bulla Park pipeline, whilst both of the latter pipelines provide alternate feeds in to the Moomba to Sydney pipeline.

In this context, it is appropriate to consider the regulatory framework applying to the planning and construction of gas transmission pipelines with a view to developing enhanced market signals for transmission pipeline investment that recognise the sum of the benefits to all participants and that encourage proponents to invest on this basis.

Finally, electricity has long been considered a substitute for gas, and has to some extent provided competition to gas as an energy source. However, where electricity is generated from gas, this competition ceases to exist. A competitive energy framework for gas supply is therefore likely to increase in importance over time.

3.5 Development Paths for New Power Stations

Development paths for new baseload generation options require specific activities to be undertaken to ensure a project is delivered which meets intended needs, and budget and timing requirements. These activities include:

1. recognising of the need for new capacity or market opportunity
2. identifying a suitable site or sites well located in relation to fuel supply and transmission, with sufficient land area and buffer zones to minimize impacts on local residences, and likely to be able to achieve acceptable licence and planning conditions
3. undertaking preliminary technical and environmental baseline studies to confirm a preferred site
4. undertaking detailed studies to confirm technical feasibility and ensure capability to meet known licensing requirements
5. undertaking the planning approvals process to secure Development Approval and obtain required licences
6. undertaking market analysis to confirm financial viability and timing requirements
7. committing to project activities required to secure funding, design, specify, award contracts, construct, commission and achieve commercial operation.

Based on recent power station developments in Australia[27], it can typically take up to six years from the initiation of site selection and feasibility studies to reach financial close for a new power station. Securing a suitable site, and undertaking necessary feasibility studies can take up to two years whilst the preparation of an Environmental Assessment and securing Development Approval under the Part 3A of the *Environmental Planning and Assessment Act 1979* can take up to a further two years. Detailed design, letting of construction contracts and achieving financial close can take one to two years.[28]

While the Development Approval process and detailed design can overlap to a degree these activities together can take up to three years.

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[27] e.g. Millmerran, Callide C, Tarong North and Kogan Creek

[28] e.g. Gas Wambo's Wagga proposal, Macquarie Generation's Tomago proposal and TXU's(now TRUenergy) Tallawarra proposal all appear in NEMMCO's 2003 Statement of Opportunities, but are yet to be commissioned.

Table 3.13 summarises recent experience on new coal-fired power projects in Queensland in terms of the timeframe from in-principle approval to financial close. The timeframe from initial announcement to securing all approvals and financial close can vary markedly given the specific circumstance of any given project.

Table 3.13: Timeframe of recent coal-fired power station project development

Project	Initial Announcement	Project Approvals and Major Agreements in Place	Comment
Millmerran 2x426MW	Oct 1997 – Qld Government announce project short listed	May 1999 – financial close	Qld Government provided facilitation support
Tarong North 1x450MW	May 1998 – Qld Government announce in principle approval	January 2000- work commences on site	Expansion at an existing site. Partner withdraws September 1999. Project reduced to one unit November 1999
Kogan Creek 1x750MW	July 1999	May 2004 – construction agreement	Project suspended in 2000

Once financial close has been achieved mobilisation and on site construction work including commissioning for a coal-fired power station can take up to four years inclusive. So in effect the last three stages of the development pathways can take seven years from the submission of a development approval to running a plant at high capacity factors. The construction time for gas-fired powers stations can be around two years (plus pre-investment works). [29]

Work has been undertaken in recent times by interested parties (both Government owned and private sector energy businesses) to identify potential sites for baseload generation in New South Wales.

In the case of the private sector there has been a strong focus on investment in gas-fired peaking capacity. At least one of these peaking projects (Uranquinty) which is being constructed by Babcock & Brown has potential for conversion to baseload duty at a later date. One major gas-fired project (Tallawarra), which is being constructed by TRUenergy, is expected to fulfil an intermediate to baseload duty.

[29] According to the NEMMCO 2006 Statement of Opportunities, Tallawarra was announced as committed prior to 31 June 2006, and is to be commissioned prior to Winter 2008.

The electricity generating State Owned businesses have been examining opportunities for adding baseload increments of coal-fired generating capacity, on a stand-alone basis (at Ulan adjacent to the existing Ulan Coal Mine), or associated with more intensively utilizing existing landholdings and sharing facilities (Bayswater B and Mt Piper 3 & 4). Some State Owned businesses have also been identifying sites having potential for major gas-fired baseload generation (Bamarang, Marulan and Tomago). One is constructing a major gas-fired peaking facility (Colongra on the existing Munmorah power station site) which is capable of being converted to baseload duty.

The Inquiry notes that Development Activities 1 to 4 have essentially been completed on a number of coal-fired and gas-fired sites in New South Wales identified by the .proponents.

Securing Development Approval is complete or in process for a number of gas-fired sites, and accordingly one or more gas-fired projects could be completed by or before 2013 if required.

The Development Approval process has not yet started for any of the coal-fired sites. Given that this activity can be protracted particularly in the case of a coal-fired plant this represents a key risk to coal-fired development. Assuming a four year construction period and two years to secure Development Approval and financial close, it is unlikely that a coal-fired development could be operational before 2013 - 2014. For this reason it is considered that the planning approval process for the coal-fired options should be undertaken as soon as possible.

4. The Impact on Electricity Demand of Energy Efficiency

Key Findings

- Energy efficiency can and should play a significant role in helping to achieve the NSW Government's energy and climate change policy objectives.
- Enhanced energy efficiency can contribute to reducing electricity consumption. It is unlikely to offset the need for new investment in baseload generation in New South Wales in the short to medium term.
- The NSW Government should continue to explore options to enhance the role of energy efficiency and consider extra measures to tackle ongoing barriers to the uptake of cost-effective investment in energy efficiency.
- The Government should evaluate the case for replacing the Demand Side Abatement (DSA) Rule with an energy efficiency target and trading scheme in the switch from the existing NSW Greenhouse Gas Reduction Scheme to a national emissions trading scheme. This will help keep incentives for energy efficiency in place.

4.1 Introduction

The Inquiry was keen to examine the factors that could defer the need for and timing of investment in baseload generation in New South Wales. Energy efficiency and, to a lesser extent, demand management have key roles to play.

This chapter discusses the benefits of improved energy efficiency and identifies barriers to its uptake.

It outlines energy efficiency programs which are currently operating in New South Wales. These include State-based programs initiated by the NSW Government as well as national programs in which New South Wales participates. Where possible, the chapter examines the performance of these programs, specifically their impact on electricity demand to date and in the future.

The chapter then considers options for further initiatives by the Government which have been raised in submissions to the Inquiry.

As discussed in Chapter 2, TransGrid do not explicitly identify the contribution that energy efficiency makes to reducing the growth in energy demand. But energy efficiency is implicitly factored into their work, through their forecast of a continuation of the reduced rate of energy demand growth observed since 2001.

TransGrid forecasts that total energy consumption in New South Wales in 2016-17 will be some 2,000GWh lower than it would be if energy consumption growth continues at the pre 2001 rates. Despite data limitations, this is at least in part due to energy efficiency. For indicative purposes, this is equivalent to around half the maximum annual output of one 660MW coal-fired unit at the Vales Point power station[1].

This is in addition to the reduction in forecast scheduled generation in 2016-17 following the 4,000GWh contribution from renewable energy and embedded generation.

Energy efficiency is an increasingly important part of the NSW electricity system. But the Inquiry has noted the difficulty in identifying a firm number for the contribution of energy efficiency to meeting the State's future energy needs. The figures in this chapter about existing and potential programs (both in New South Wales and nationally) are often indicative projections about the program's potential impact over a number of years.

The NEMMCO/TransGrid projections of the potential contribution of energy efficiency programs take into account existing measures, but do not forecast the potential contribution of future programs.

The Inquiry has taken a similar approach. Chapter 2 found that electricity consumption forecasts indicate that New South Wales needs to be in a position where new baseload generation can be operational by 2013-14. Enhanced energy efficiency could delay the need for new baseload capacity, but it would not be prudent to rely on this being the case, particularly in view of the lack of reliable information about the actual electricity savings to date from existing energy efficiency programs, and the uncertainties surrounding future electricity savings from existing and potential energy efficiency measures. As data about the impact of energy efficiency programs emerges market participants will be able to factor this into their models and adapt their views on the timing of new baseload.

[1] A 660MW unit operating at a 75 per cent utilisation factor produces 4336GWh per annum.

4.2 Demand Side Measures

Measures aimed at addressing the demand side of the energy supply/demand balance are known as demand side measures (DSM). There are two main types – energy efficiency and demand management. Energy efficiency and demand management are terms that are often used interchangeably. Although they have some overlapping objectives, they are conceptually different, particularly when considering the timing and need for new baseload generation capacity.

What is 'energy efficiency'?

'Energy efficiency' refers to the amount of energy required to produce a unit of output. Therefore, improved electrical energy efficiency means that fewer megawatt hours are needed to produce the same level of output. Measures aimed at improving electrical energy efficiency focus on activities such as reducing the amount of electricity used by appliances and reducing the amount of electricity consumed by residential and commercial buildings without lowering comfort levels. As such, improvements to energy efficiency will reduce overall energy consumption.

Energy efficiency can therefore reduce electricity demand during both peak and non-peak periods. As Origin Energy has noted in its submission to the Inquiry, 'energy efficiency measures can delay the need for new generating capacity'.[2]

Reduced energy consumption achieved through enhanced energy efficiency has the benefit of reducing greenhouse gas emissions, as well as the benefit of reducing generation and other infrastructure needs.

What is 'demand management'?

This report uses the term 'demand management' to refer to actions aimed at shifting the timing and level of peak demand for electricity. Currently, a relatively large percentage of the assets required to deliver electricity to consumers is used for a small percentage of time (that is, at times of peak demand). Demand management measures aim to reduce the scale and frequency of these peaks, and therefore reduce the need to call on peaking generators. Demand management measures can alleviate network congestion, improve network and other asset utilisation and potentially reduce capital expenditure on the augmentation of networks. As a result, demand management can result in price benefits for customers over the medium to long term.

[2] Origin Energy submission, p14.

However, as demand management does not necessarily decrease total energy consumption, it does not have a significant influence on the need or timing for baseload generation. For this reason, this chapter focuses on energy efficiency. Appendix 4.1 discusses existing demand management initiatives and options for consideration.

4.3 Energy Efficiency Measures

What can energy efficiency deliver?

There is a general acceptance in the community that there is significant potential to improve the efficiency with which electricity and other forms of energy are used. Submissions to the Inquiry expressed general support for greater use of measures to improve energy efficiency and demand management.

Opportunities for improving energy efficiency include projects which upgrade lighting in commercial office buildings, replacing motors used in industrial processes and the installation of cogeneration plants. These projects and others like them are regarded as having untapped potential to meet energy needs in a reliable and cost-effective manner, with low environmental impacts, compared to traditional generation and network solutions.

In 2003, the Ministerial Council on Energy noted that energy efficiency efforts to date 'have captured only a small proportion of the cost-effective energy efficient potential'.[3] The Council's analysis 'indicated significant energy efficiency improvement potential available to be exploited across all sectors of the economy.'[4] Cost-effective measures were identified with the potential to save electricity consumption by 35 per cent in the residential sector, 28 per cent in the commercial sector and 25 per cent in the manufacturing sector. The cost-effective measures were those defined as having an average four-year payback using technologies that are currently commercially available. The numbers assume a 50 per cent penetration over a twelve year period.

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[3] COAG Ministerial Council on Energy, Energy Efficiency and Greenhouse Working Group, Towards a National Framework for Energy Efficiency – Issues and Challenges, November 2003, p6.

[4] Ibid, p7, data at Figure 4

Clearly there is enormous potential. A preliminary economic assessment of potential electricity savings[5] undertaken for the National Framework for Energy Efficiency (NFEE) shows that for NSW electricity savings could be more than 15,000GWh[6]. This assumes the uptake of technologies which were commercially available at the time and would be purchased if the payback period was four years or less. More recent work[7] undertaken for NFEE shows that projected energy savings from Stage I measures, which includes a smaller range of energy efficiency programs than the original study, could be 3,900GWh by 2015.[8] By way of comparison the expected maximum energy capacity of the Wallerawang power station is 6,570GWh. NFEE is discussed in more detail in section 4.5. Australian Governments are currently considering a number of NFEE Stage II measures which would aim to tap more of the potential energy savings.

In assessing the need and timing for new baseload generation in New South Wales, the Inquiry considers that:

- A number of the main energy efficiency programs have been introduced in the last few years and therefore reliable measurements of the impact of these programs are still being developed.
- Despite the promising potential, there are a number of impediments or barriers which are limiting the uptake and effectiveness of energy efficiency investments (as outlined in section 4.4).
- Overestimating the impact of energy efficiency could result in investment in baseload being planned too late.

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[5] COAG Ministerial Council on Energy, Energy Efficiency and Greenhouse Working Group, *Towards a National Framework for Energy Efficiency – Issues and challenges, Discussion Paper,* November 2003

[6] NSW Department of Water and Energy estimates. Total energy (electricity and gas) savings are 213PJ. Assuming that 80 per cent of the savings are attributable to electricity, this is equivalent to 47,300GWh nationally. As NSW consumes around one-third of all electricity nationally, savings in NSW are estimated to be around 15,700GWh.

[7] Energy Efficiency Working Group, National Framework for Energy Efficiency Stage Two, Consultation Paper, August 2007

[8] NSW Department Water and Energy estimates. This is based on national energy savings of 42PJ (11,700GWh). NSW consumes approximately one third of all electricity nationally. Therefore, savings in NSW are estimated to be 3,900GWh.

The Inquiry notes that environmental groups and the sustainable energy industry agree that enhanced energy efficiency, by itself, will not be enough to meet NSW future electricity needs. For example, the Business Council for Sustainable Energy told the Inquiry that 'To meet the NSW Government's commitment to reduce NSW greenhouse gas emissions to 2000 levels by 2025, the output from existing coal fired generators will need to fall. The forecast growth in demand will need to be met by energy efficiency, renewable energy and efficient use of natural gas'[9]. Similarly, the joint submission to the Inquiry from the Total Environment Centre, the Nature Conservation Council of NSW and Greenpeace said that 'NSW can easily and cheaply meet all its future energy needs with low or no emissions energy technologies – demand management, energy efficiency, renewable energy and gas-fired power'.[10]

Why has energy efficiency not delivered on its potential?

In an efficient market environment, cost-effective energy efficiency investments should occur without Government incentives. However, it is clear that such investments are not happening at the necessary level.

The Inquiry has found evidence that some of the barriers which limit the uptake by households and businesses of investments in energy efficiency constitute a failure of the market.[11]

Governments and industry around the world face a similar situation. McKinsey Global Institute estimates that over 80 per cent of cost-effective energy efficiency opportunities will not be realised without public policy interventions. [12]

Key reasons why energy efficiency has not achieved its potential include a lack of comprehensive information for consumers about products and their electricity requirements, a lack of effective price signals to customers and market issues.

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[9] Business Council for Sustainable Energy, submission, p7.

[10] Total Environment Centre, Nature Conservation Council of NSW, Greenpeace, submission, p3.

[11] Recent relevant reports include:

- IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services Final Report*, October 2002;
- Charles River Associates and Gallagher & Associates, *Electricity Demand Side Management Study*, prepared for VENCorp, 7 September 2001;
- COAG Ministerial Council on Energy, Energy Efficiency and Greenhouse Working Group, *Towards a National Framework for Energy Efficiency – Issues and Challenges*, November 2003; and
- South Australian Electricity Demand Side Measures Task Force Final Report, June 2002.

[12] McKinsey Global Institute, *Curbing Global Energy Demand Growth: the Energy Productivity Opportunity*, May.2007.

Information barriers

In some cases, consumers and investors may not fully understand the nature of a product at the time of investment. Product standardisation and energy labelling, such as the national Minimum Energy Performance Standards program discussed in section 4.6, can help to address this.

Customers may also have the perception that there will be significant administration costs associated with their decision to purchase energy-efficient equipment. This can be addressed by reliable, independent information sources and by convenient and transparent calculation methods to assist decision-making.

Where customers receive information from a supplier (e.g. information provided by appliance and energy retailers), they may have some uncertainty about its reliability. This can be addressed by the provision of independent information from reliable sources.

Customers may lack information on how their choice of technologies and their pattern of electricity use actually relates to the size of their electricity bill. This is particularly the case where bills may arrive infrequently and do not provide disaggregated information about electricity use. As a result, appliance purchase decisions may be made without sufficient consideration of more energy-efficient options. This demonstrates the need for more effective price signals to consumers.

The Ministerial Council on Energy is considering options for providing small electricity users (households and small businesses) with more detailed data on their electricity consumption patterns. This is to inform customers how they can reduce electricity consumption as they will have greater knowledge of which activities and appliances use the largest amount of electricity.

Price signal barriers

Even when customers have detailed information about the energy consumption of their purchasing options, effective electricity price signals are necessary. Without such signals, consumers cannot fully assess the financial value of the energy savings resulting from the purchase of a more energy-efficient appliance.

If electricity prices are relatively low (for example, do not fully reflect the full environmental costs of supplying electricity to consumers), energy costs are likely to be a small proportion of total business costs or consumer income and are less likely to provide an incentive to select a more energy-efficient option.

Similarly, the higher upfront capital costs for energy-efficient products can discourage customers from purchasing energy efficiency measures. This could be addressed by third party financing options and special funding. High upfront capital costs may also present a barrier where access to capital is limited and other priorities may prevail. For many investments (such as buildings or heavy machinery), capital stock turnover rates are low and are characterised by large sunk costs and tax rules that require long depreciation.

Prices for energy-efficient appliances may be higher than competing, less efficient products. The lack of appropriate price signals means that, when purchasing appliances, the buyer has limited ability to estimate accurately how long it will take to realise a financial benefit from investing in the more energy efficient product (the 'pay-back' period). In other words, the buyer's perceived risk may differ from the actual risk. This could be overcome by way of demonstration projects and routines to make life-cycle cost calculations easy.

The Inquiry recognises that many services provided by electricity are essential and that, even where customers have access to full information and where price signals are substantial, customers will still display price-inelastic behaviour.

At present, electricity prices in New South Wales and the rest of Australia do not fully reflect the environmental costs of supplying electricity to customers. Chapter 5 discusses work underway to develop a national greenhouse gas emissions trading scheme which, when implemented, will result in electricity prices that include environmental externalities.

Market barriers

Even where customers have access to comprehensive information and where price signals are strong, there may remain barriers to energy efficiency that arise from the structures providing different incentives to different stakeholders.

Perhaps the best known of these is the split between incentives on landlords and those on tenants. Tenancy arrangements provide few incentives for landlords or tenants to make cost-effective energy efficiency investments in rented properties. NCOSS is of the view that the responsibility, and associated cost, of installing energy-efficient devices in rental accommodation should be met by the landlord, rather than the tenant.[13]

[13] Council of Social Service of NSW, submission, p2.

The submission to the Inquiry by the Major Energy Users raised a second issue - that the National Electricity Market is characterised by, inter alia, the lack of effective demand-side response. [14] The Ministerial Council on Energy is currently examining demand-side bidding with a view to amending the National Electricity Rules (see Appendix 4.1 for details).

Where barriers to energy efficiency exist, it is common practice for Governments around the world to implement programs aimed at addressing them.

4.4 Existing NSW Energy Efficiency Initiatives

Since 1998, the NSW Government has been implementing programs to encourage energy efficiency in both the public and private sectors. These programs include contestable funding for energy efficiency and demand management projects and compulsory schemes aimed at businesses and households.

In this context, it is worth noting some of the interesting ideas which have been raised in submissions to the Inquiry and revisiting key energy efficiency and demand management programs currently operating in New South Wales. Some of these programs have coverage only within New South Wales, while others are national programs in which New South Wales participates.

The following review focuses on energy efficiency measures, as these have the potential to significantly influence electricity usage levels, and thus both the need and timing for base load investments, and the level of greenhouse gas emissions. Demand management measures are outlined in Appendix 4.1.

Greenhouse Gas Reduction Scheme – DSA Rule

The Demand Side Abatement Rule ('the DSA Rule') of the NSW Greenhouse Gas Reduction Scheme (GGAS) allows scheme participants to earn tradeable certificates (called NSW Greenhouse Abatement Certificates, or 'NGACS') for carrying out activities that reduce the consumption of electricity from the grid.

[14] Major Energy Users Inc submission, pp9 and 27.

The DSA Rule defines five main types of eligible projects:

- energy efficiency projects that modify existing energy consuming equipment, processes or systems (called 'Installations' in the DSA Rule), or which modify the usage of Installations;
- energy efficiency projects that replace existing Installations with other Installations that consume less electricity;
- energy efficiency projects that install new Installations that consume less electricity than other Installations of the same type;
- fuel switching projects that substitute one source of energy for another; and
- on-site electricity generation that replaces supply from the National Electricity Market.

Savings to date and future projections

As of July 2007, over 13 million abatement certificates, representing a reduction of 13 million tonnes of greenhouse gas[15] emissions, have been created under the DSA Rule.[16] The scheme prompted a wide range of DSA projects – 111 from Scheme commencement through to release of the 2006 Annual Compliance Report by IPART, the Scheme administrator.

There is no published information which indicates the number of megawatts or megawatt hours that have been saved due to compliance with the DSA Rule. This is mainly because the primary focus of GGAS is the reduction of greenhouse gas emissions, rather than the demand for electricity.[17]

However, it is possible to undertake analysis of the data published by IPART in its 2006 Report, to extrapolate likely energy savings. The NSW Department of Water and Energy has undertaken preliminary analysis of the lighting, industrial and commercial energy efficiency accredited DSA projects.

From lighting projects alone, it is estimated that more than 9 million compact fluorescent lamps have been installed with a saving of at least 300GWh (assuming two hours of operation per day), with a further 100GWh from industrial and commercial projects. Conservatively, it is further estimated that from the projects implemented in the first four years of GGAS, a load reduction of some 240MW was achieved by 2006.

[15] This refers to carbon dioxide equivalent.

[16] GGAS Registry, 3 July 2007.

[17] Further information can be found at www.greenhousegas.nsw.gov.au.

The policy environment in which GGAS operates is changing. When GGAS is replaced by a national emissions trading scheme, it is unlikely there will be an equivalent to the DSA Rule. This would mean that demand-side abatement in New South Wales will not be as commercially attractive as is currently the case, unless a program to encourage energy efficiency is implemented to complement the emissions trading scheme. This latter option is discussed in section 4.6.

Energy Savings Action Plans

The preparation of Energy Savings Action Plans is a mandatory scheme for large energy users in New South Wales.[18] The program aims to encourage a better understanding of energy use by business, government agencies and local councils and establish detailed plans of action for savings.

Businesses and NSW Government agencies using more than 10GWh per year at a site and local councils in New South Wales with populations larger than 50,000 are required to prepare a plan. While organisations are required to report annually on outcomes from their plans, implementation remains voluntary.

To date, approximately 50 per cent of the plans have been approved, with cost-effective opportunities of nearly 5,000TJ identified. These savings are from all fuel sources with the majority of these savings not electricity related. Electricity savings identified to date are approximately 250GWh and 25MW[19].

There are further untapped savings identified as 'potentially cost-effective' projects, which may become financially viable in the future. The estimated total potential from the approved plans is 5,500TJ of total energy, with electricity savings of 600GWh and 25MW.[20]

Note that the implementation component of the scheme is voluntary. Implementation of projects is expected to be highly variable and dependent upon a number of barriers unrelated to the financial cost-effectiveness of the project. From late 2008 a more accurate assessment of the realised savings will be known.

[18] The requirements were introduced in May 2005 under the *Energy Administration Amendment (Water and Energy Savings) Act 2005.*

[19] Information from Savings Action Plans submitted to NSW Department of Environment and Climate Change.

[20] Ibid.

Climate Change Fund

The Climate Change Fund, which incorporates the former Water and Energy Savings Funds, supports energy and water savings in New South Wales. The available funding is projected to run from 2005-06 to 2011-12 and currently includes the following energy savings elements:

- energy savings projects from contestable funding rounds in 2005-06 and 2006-07 - $90 million [21]
- Residential Rebates Program (insulation and hot water systems) - $100 million
- Renewable Energy Development Program - $40 million
- Public Facilities Program - $30 million
- Schools Energy Efficiency Program - $20 million.

As most programs are in the early stages of development, there is little verified savings data to allow an estimate of the savings expected from the fund. Beginning from 2009-10, an assessment of the realised savings will be available.

BASIX

The Building Sustainability Index, BASIX, is a planning initiative of the NSW Government. It requires all new homes in New South Wales to use up to 40 per cent less potable water and produce up to 40 per cent fewer greenhouse gas emissions than the average home (the energy target varies according to building type and location). In other words, new dwellings have to be more energy-efficient. BASIX also applies to alterations and additions to existing homes worth $50,000 or more.

Each development application for a residential dwelling (single or multi-unit) must be submitted with a BASIX certificate. A certificate is issued once a BASIX assessment has been satisfactorily completed, using the on-line tool on the BASIX website which measures the potential performance of new homes against water, energy and thermal comfort indices. All the major technologies in the home that affect energy consumption are measured, including hot water, heating and cooling, lighting, and cooking.

[21] NSW Department of Environment and Climate Change estimates.

BASIX has also stimulated the up-take of cogeneration technology, which displaces energy consumption from the grid (that is, scheduled generation). The application of BASIX to multi-unit developments has boosted interest in cogeneration as a cost-effective greenhouse abatement and energy efficiency strategy in the residential sector. The BASIX Multi Unit Cogeneration Demonstration Project has demonstrated how this technology can be embedded within new residential developments. [22]

Savings to date and future projections

By 2014-15, BASIX is estimated to save 800,000 tonnes of carbon emissions annually from reduced use of electricity and gas.[23]

The NSW Department of Planning is undertaking a monitoring study of completed BASIX-compliant homes, in order to assess the level of water and energy savings achieved. This study is part of a broad monitoring framework. The results of this study will be used to ensure the BASIX policy delivers on its sustainability objectives, as well as refine and improve data and key calculations in the BASIX tool, ensuring the long term success of the policy.

BASIX Energy Targets will be reviewed in 2008 to determine whether a further increase in energy targets is appropriate.

Government Energy Management Policy

The Government Energy Management Policy (GEMP) is NSW's response to the National Greenhouse Strategy requirement for all Australian Governments to reduce greenhouse gas emissions from their own operations. Improving the energy efficiency of buildings is one important measure in the Strategy.

NSW General Government agencies account for around 4.5 per cent of total electricity consumption in New South Wales, and provide considerable opportunity to reduce the State’s overall energy consumption.

Announced in November 1998, GEMP established targets to reduce State-wide total energy consumption in Government buildings by 15 per cent by 2001-02 and 25 per cent by 2005-06 (from 1995-96 levels), where cost-effectively feasible.

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[22] The GridX residential project at Glenfield, a private initiative, has also implemented cogeneration.

[23] Press release from the Hon. Frank Sartor MP, Minister for Planning, 29 June 2007

Additional related targets have been set since 1998. Buildings owned or tenanted by Government are to achieve certain star ratings under the Australian Building Greenhouse Rating (ABGR) Scheme and all agencies listed under Schedule 1 of the *NSW Public Sector Management Act 1988* must purchase electricity with at least 6 per cent accredited GreenPower (i.e. power from renewable energy sources). The NSW Greenhouse Plan, released in November 2005, included commitments to 'strengthen the Government Energy Management Policy' (initiative 3.1.11).

The NSW Department of Environment and Climate Change facilitates energy efficiency upgrades by helping agencies access the $40 million NSW Treasury Loan Fund, thereby assisting to reduce energy use, reduce greenhouse gas emissions, increase savings for government and provide jobs in the energy services sector. The Fund can be accessed by State Government agencies for energy efficiency upgrades by way of Energy Performance Contracts or the Government Energy Efficiency Investment Program.

The Department manages the collection of GEMP data from Government agencies and is responsible for general oversight of the GEMP, including policy implementation and review, in cooperation with the Department of Commerce.

4.5 Existing National Programs in which NSW Participates

National Framework for Energy Efficiency (NFEE)

The NFEE is the umbrella for a number of energy efficiency programs, including the:

- Minimum Energy Performance Standards (MEPS) and Energy Labelling for Electrical Products
- Energy Efficiency Opportunities.

NFEE focuses on demand-side energy efficiency, primarily in the residential, commercial and industrial sectors. A guiding principle is national coordination and consistency, where appropriate, in program delivery and communications.

NFEE Stage I builds on existing capacity and capabilities developed by jurisdictions with an increased focus on national coordination. It consists of policies which extend, or further develop, cost-effective energy efficiency measures currently being implemented at a national or jurisdictional level.

Primary measures under Stage I include MEPS and Energy Efficiency Opportunities.

Stage I will be completed by 2008-09. Planning is currently underway for Stage II which will commence in 2008-09. The focus of measures proposed for Stage II is on the largest energy using and end use technologies in key industrial, commercial and residential sectors. MEPS for electrical appliances and equipment will continue and expand in Stage II and gas appliances and equipment will be included for the first time.

Savings to date and future projections

There are currently no available published data that quantifies the impact of Stage I on the overall demand for electricity. To improve the coordination of energy efficiency program monitoring, reporting and evaluation, the NFEE Steering Committee has developed a collection, reporting and evaluation framework ('D-REF'). It will be used to determine the efficacy of Government funded energy efficiency programs, identify deficiencies in current programs, and inform decisions on future funding priorities and program design.

D-REF will be used to report on and evaluate the actual, as opposed to the projected, impacts of NFEE Stage I. Individual jurisdictions may also use it to report on and evaluate the implementation of jurisdiction-specific energy efficiency programs[24].

Minimum energy performance standards and energy labelling for electrical products

A major aspect of NFEE is the Minimum Energy Performance Standards (MEPS) and energy labelling of electrical appliances. MEPS and energy labelling are made mandatory in Australia by state government legislation and regulations which give force to the relevant Australian Standards.

The program is coordinated nationally under the auspices of the MCE, with joint funding for activities such as check testing, standards development and website development, provided by the Commonwealth, States and Territories. The New Zealand Government also participates in and financially contributes to this program.

MEPS apply to certain electrical equipment and appliance types while energy labelling is confined to household electrical appliances. Regulations specify the general requirements for MEPS and energy labelling, including offences and penalties if a party does not comply with the requirements.

[24] National Framework for Energy Efficiency, http://www.nfee.gov.au/

If a product is regulated by MEPS then it must meet a specified minimum energy efficiency level. Products which do not achieve this level cannot be sold in Australia. The energy rating label enables consumers to compare the energy efficiency of domestic appliances on a fair and equitable basis. Labelling also provides an incentive for manufacturers to improve the energy performance of appliances.

The energy rating label has two main features:

- the star rating (determined from energy consumption and capacity of the product) gives a comparative assessment of the model's energy efficiency; and
- the comparative energy consumption provides an estimate of the energy consumption of the appliance based on the tested energy consumption and information about the typical use of the appliance in the home.

It is currently mandatory for the following household electrical appliances to carry an approved energy label when offered for sale in Australia and New Zealand: refrigerators and freezers, clothes washers, clothes dryers, dishwashers and air conditioners. The following electrical products must meet MEPS: refrigerators and freezers, air conditioners, mains pressure storage water heaters, three phase electric motors, fluorescent lamp ballasts, linear fluorescent lamps, refrigerated display cabinets and distribution transformers.

The product coverage will be expanded in the future to include televisions, home entertainment equipment, commercial chillers (used for commercial building climate control), domestic gas water heaters and domestic gas space heaters.

Savings to date and future projections

In 2002, IPART reported that market research has shown a very high level of customer awareness of energy rating labels, and a high and growing level of influence of the labels when consumers purchase an appliance. According to IPART, the introduction of MEPS has also made a significant impact on improvements in the energy efficiency of household appliances.[25]

[25] As reported in IPART's *Inquiry Into the Role of Demand Management and Other Options in the Provision of Energy Services Final Report*, October 2002, p54

There is evidence that the Equipment Energy Efficiency program is delivering tangible benefits through measurable energy efficiency gains for regulated products. For all appliances covered by the energy labelling program in Australia, the energy consumption is decreasing.[26]

The cumulative effect of the appliances and equipment program (i.e. MEPS and labelling) implemented under NFEE Stage I and proposed to be implemented under NFEE Stage II is estimated to result in annual energy savings in New South Wales of more than 1,000GWh by 2020.[27] This figure includes a small amount of energy savings from gas equipment and appliances.[28]

In addition to programs introduced nationally by the MCE, energy users in NSW are also covered by a new Commonwealth Government mandatory program.

Energy Efficiency Opportunities

Energy Efficiency Opportunities is a national mandatory energy efficiency program for the largest 250 energy using corporations in Australia. It aims to cover 60 per cent of Australia's commercial and industrial energy use and 40 per cent of Australia's total energy use.

The program's requirements are set out in the *Energy Efficiency Opportunities Act 2006* which came into effect on 1 July 2006. The program is part of the NFEE.

Corporations using more than 0.5 PJ of energy per year are required to participate in the program, with the participating corporations required to assess 80 per cent of their total energy use, and all sites using more than 0.5 petajoule per year, within a five year assessment cycle. They must report publicly on the results of the assessment and the business response. Decisions on energy efficiency opportunities remain at the discretion of the business.

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[26] Greening Whitegoods – *A Report into the Energy Efficiency Trends of Major Household Appliances in Australia from 1993 to 200*', July 2006

[27] *National Appliance and Equipment Energy Efficiency Program, Projected Impacts 2005-2020, Report No. 2005/05*

[28] Further information can be found at www.energyrating.com.au.

A number of businesses in New South Wales are required to meet the obligations of both Energy Efficiency Opportunities and the Energy Savings Action Plans. Administrators of both programs work closely together to ensure, where possible, that work undertaken in one program can be used in the other where it meets requirements. Both programs share a similar intent – to ensure that a rigorous and comprehensive technical assessment of energy efficiency opportunities is conducted.

Savings to date and future projections

Companies were required to register by 31 March 2007. There is, at this stage, little published data to quantify the extent to which Energy Efficiency Opportunities will succeed in reducing electricity demand. Early projections do not provide estimates of energy savings in terms of megawatts or megawatt hours.[29]

National Australian Built Environment Rating System

The National Australian Built Environment Rating System (NABERS) is a performance-based rating system for existing buildings. It rates a building on the basis of its measured operational impacts on the environment. Building owners, managers or occupants can manage and reduce these environmental impacts.

NABERS is designed to provide users with a simple indication of how well they are managing environmental impacts, compared with peers and neighbours. NABERS is a national initiative managed by the NSW Department of Environment and Climate Change.

The Australian Building Greenhouse Rating (ABGR) was developed by the NSW Government, and is now a component of NABERS. It is a voluntary scheme applying to the actual performance of new and existing commercial office buildings and promoting improvements in performance through a star rating scheme.

ABGR can be used to guide the design of new office buildings to deliver a high performance rating through the 'commitment agreement' process – the developer commits that the building will achieve a specific ABGR rating once built and occupied and the rating is subsequently undertaken to verify that the commitment has been met.

In 2004, the NSW Government committed to use the ABGR to measure and improve the performance of buildings it owns or leases.

[29] 'Energy Efficiency Opportunities – FAQ', http://www.energyefficiencyopportunities.gov.au

Verified annual savings from building improvements recorded to date in New South Wales are currently 35,000 tonnes of carbon dioxide equivalent per year with an estimated three per cent annual growth rate[30]. As the program is structured to track greenhouse savings, the electricity savings component is unknown. Unverified estimates for the purposes of this report indicate electricity savings of 30 to 35GWh.

National roll-out of smart meters

In February 2006, COAG decided that there would be a nationwide roll-out of smart meters from 2007, where this is cost-effective for households. Smart meters are communications-enabled 'time-of-use' meters. They can indicate the overall level of electricity consumption at any given time, and therefore allow customers to adjust their own consumption in response to this information. COAG considered that the rollout of smart meters is a key means by which demand management can be undertaken by individual consumers[31].

A key issue is that the success of smart meters in demand management terms generally depends on active user engagement and awareness. Before the roll-out commences, a national cost-benefit analysis is being undertaken. The analysis will take into account the different circumstances in each State and Territory.

Time-of-use pricing is designed to provide a price signal to end-users about the cost of supplying electricity at different times of the day. Peak period electricity is the most expensive. The provision of a price signal will encourage customers to shift their electricity consumption to the cheaper periods during the day. This will minimise the need to install additional infrastructure to supply peak demand.

There are various technologies available for smart metering, ranging from basic units to those with internal electronic screens to inform consumers of current pricing information, to those that can automatically turn appliances down or off during peak periods. The technology used for a smart metering rollout may affect the benefits achieved.

[30] Demonstrated savings as evidenced by repeat ratings of commercial offices in NSW, as at June 2007, taken from internal ratings database by NSW Department of Environment and Climate Change.

[31] The Inquiry recognises that the roll-out of smart meters is probably more related to demand management than to energy efficiency. EnergyAustralia has provided evidence to the Inquiry that measures aimed at enhancing demand management can also result in lower electricity consumption. For this reason, the Inquiry has decided to include the national roll out of smart meters in this overview of existing energy efficiency programs.

In practice, smart meters may provide benefits for demand management in peak periods, provided that the consumers are subjected to cost reflective pricing impacts during those times.

Although smart meters are primarily thought to influence the use of appliances such as air conditioners, which correlate to peak consumption periods, they may also contribute to reducing total energy consumption.

In New South Wales, the electricity distribution companies EnergyAustralia, Integral Energy and Country Energy have for some time been trialling and installing smart meters on a new and replacement basis. Between them a total of more than 250,000 meters have installed.[32]

4.6 Options for Consideration by Government

The Inquiry has reviewed relevant literature and submissions made on energy efficiency. It is recommended that the Government consider the following options as part of its ongoing policy development process.

Pricing issues

A number of submissions made to the Inquiry emphasised the importance of electricity price reform. Some of the suggestions put forward are that the Government should:

- introduce time-of-use electricity pricing and/or peak pricing
- require all electricity retailers to offer flexible tariffs based on time of use
- ban inverted electricity tariffs
- introduce more cost-reflective pricing (including signalling the cost of emissions permits)
- remove the subsidy from electricity prices in rural and remote areas
- expedite the roll-out of smart meters.

[32] Ministerial Council on Energy, *Smart Meters Information Paper*, January 2007, p10.

An important component of providing electricity consumers with price signals is ensuring that they have the information to respond to the signal. This partly involves ensuring that customers are aware of the true cost of delivering electricity to their homes and businesses. As noted by Origin Energy in its submission to the Inquiry, 'without cost-reflective prices, prices are artificially low, and this entails a price barrier for consumers, which discourages energy efficiency measures.'[33]

In New South Wales, as in most jurisdictions, the prices paid by many small users of electricity continue to be subject to some form of regulation.[34] IPART, in its June 2007 review of regulated retail prices, explicitly sought to bring these prices to 'cost-reflective' levels. That is, the price paid by end-users should accurately cover the costs of electricity production and of delivering the product to where it is consumed.

New South Wales has agreed to consider the future role of regulated retail tariffs if retail competition is proven to be effective. The Australian Energy Market Commission (AEMC) will undertake a review of the effectiveness of retail competition in each jurisdiction. The New South Wales review is likely to be undertaken in 2009 to allow for the outcomes from the recent IPART review to take effect.

Providing an accurate price signal to customers also involves informing customers about the cost of supplying electricity at different times of the day. As mentioned above, the NSW Government is working within the COAG framework to rollout smart meters. New South Wales electricity distributors have been installing smart meters on a new and replacement basis since 2002, with over 250,000 smart meters now installed.[35]

Smart meters provide the opportunity for customer electricity tariffs to be varied depending on the time of day. These tariffs are known as time-of-use (ToU) tariffs. As discussed above, EnergyAustralia in its submission to the Inquiry noted that customers on ToU tariffs consumed one per cent less energy than customers who are not on ToU tariffs. These results were obtained by comparing a sample of ToU customers who had their meter changed to a smart meter but were not put on ToU tariffs.

Several submissions were of the view that electricity prices should also be structured to incorporate 'externalities' such as the impact that the production and use of electricity has on the climate. The Inquiry considers that this is best addressed through the establishment of a national emissions trading scheme. This is discussed in detail in Chapter 5.

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[33] Origin Energy submission, p18.

[34] Those small customers on 'market' contracts are not subject to price regulation. Only those small customers on 'standard form' contracts with their local standard retailer are subject to regulated prices.

[35] Ministerial Council on Energy, *Smart Meters Information Paper*, January 2007, p10.

Energy efficiency in homes

Submissions called on the Government to:

- make it mandatory for new buildings and renovations to install solar hot water (residential and commercial), heat pump or solar-compatible gas hot water systems, and phase out the use of electric hot water systems
- purchasers of electric resistance hot water systems for existing buildings should be required to take out mandatory GreenPower and purchase and install a smart meter on the hot water circuit
- pass legislation making it illegal for local governments to require planning permission for installing solar hot water, and make it illegal for local government, developers or the body corporate of residences under strata title to ban solar water heaters
- provide subsidies for owners of rental properties who might like to provide rental housing that is energy efficient, but have no financial incentive to do so
- require mandatory insulation in all new homes. Others called for the progressive installation of ceiling and cavity wall insulation in all houses that do not have it
- improve residential building design standards and retrofitting
- improve energy efficiency of low income households (e.g. by expanding the current No Interest Loans Schemes to improve access to energy efficient appliances).

The Inquiry has not evaluated any of the above options but the Government could do so as part of its ongoing consideration of energy efficiency measures.

The Inquiry considers that there may be opportunities to further address energy efficiency for existing residential dwellings, through:

- voluntary approaches, such as point-of-sale disclosure of energy performance of dwellings to advise purchasers, or an audit of houses for sale to determine opportunities to improve performance, or a rebate opportunity for purchasers who install energy efficient options in the dwellings subsequent to sale
- mandatory approaches, such as a minimum point-of-sale energy efficiency level that dwellings must meet.

Energy efficiency in commercial buildings

Commercial office buildings have a fairly standard pattern of energy consumption, with a similar number of occupants per square metre of building space and fairly standard hours spent in the building. As such, a design and operational performance approach may provide the best approach to assessing performance for sale and lease of these buildings. This approach is consistent with the NSW Government policy on ABGR, which is described in section 4.5.

The NSW Government could explore further opportunities to encourage uptake of commercial energy efficiency opportunities by:

- considering further options to expand ABGR (NABERS) coverage for commercial buildings
- mandating point of sale requirements for commercial buildings
- exploring options for commercial projects to be covered in an energy efficiency trading scheme.

In relation to the energy efficiency of commercial buildings, suggestions made in submissions to the Inquiry include:

- mandate efficiency requirements, such as requiring all existing commercial buildings to achieve a benchmark star rating
- introduce mandatory energy performance standards for all rental, government-owned and government-leased buildings
- require solar hot water in all government buildings that require hot water and have solar access
- require a minimum five star rating for all Government tenancies, new buildings and significant upgrades to existing buildings
- make it mandatory for new commercial buildings to install solar hot water
- provide incentives for net zero greenhouse impact buildings, facilitate adoption of high efficiency solutions in data centres and require new prestige buildings to integrate solar panels or other on-site renewables to generate at least 5 per cent of energy demand.

The Inquiry has not evaluated any of the above options but the Government could do so as part of its ongoing consideration of energy efficiency measures.

Energy efficiency of appliances

A number of submissions made to the Inquiry by environmental groups and other stakeholders called on the Government to:

- tighten regulations on import and manufacture of low efficiency appliances
- prevent the sale of inefficient technologies (e.g. through accelerating and enhancing the work of the Equipment Energy Efficiency Committee in overseeing minimum standards)
- set minimum appliance and equipment efficiency standards, and other efficiency requirements, for new and existing facilities to include all measures where the economic benefit exceeds costs, an explicit valuation of greenhouse emissions and continual reviews to ensure all technological developments are incorporated as soon as possible
- require mandatory energy rating and labelling of all new energy using appliances and equipment
- require Governments to purchase minimum five star rated appliances (or most efficient within a five per cent range if no five star available)
- require air conditioners to be purchased with a smart meter that allows use of the air conditioner to be controlled by both the customer and energy retailer. The energy retailer would be required by law to charge for electricity consumed according to the cost by time of day
- greater enforcement of energy performance standards for electrical products
- set minimum performance standards for street lighting
- develop a strategy to improve the lifetime performance of non-residential air conditioning systems.

The Inquiry has not evaluated any of the above options but the Government could do so as part of its ongoing consideration of energy efficiency measures.

Industrial energy efficiency

Local Government, State Government agencies and high energy using businesses are required to prepare Energy Savings Action Plans. The Minister for Environment, Climate Change and Water has the power to make implementation of these savings compulsory.

The Council of Australian Federation agreed in February 2007 that State and Territory Governments will:

> 'develop a national mandatory energy efficiency system (requiring industry to implement any energy efficient opportunities with less than a 3-year payback).'

The Western Australian Government is currently developing this proposal.

Energy efficiency trading

The DSA Rule under GGAS enables a range of demand-side abatement projects within New South Wales and the Australian Capital Territory to be accredited and generate tradable certificates.

When an emissions trading scheme is established at national level it is unlikely to include demand-side abatement measures because this could allow 'double-counting' of the emissions abatement from such measures under a cap and trade scheme. This is not a problem under the GGAS baseline and credit scheme.

The NSW Government has indicated that GGAS will end when a national emissions trading scheme is implemented. Participants in the GGAS market are already concerned about the potential future demand for energy efficiency certificates, and this is reportedly undermining confidence in the current scheme.

One option that may be worth examining in detail is the development of a separate 'white certificate' (energy efficiency) trading scheme, to continue the stimulus for demand-side projects. This could take the approach of establishing the DSA Rule as a stand-alone energy efficiency target and trading scheme.

An issue for New South Wales would be whether to include commercial and industrial energy efficiency within such a scheme. Under GGAS, commercial and industrial energy efficiency projects are eligible to create certificates.

For maximum effectiveness and regulatory simplicity, an energy efficiency trading scheme would ideally be national and complement a national emissions trading scheme. There is a possibility that Australian jurisdictions may choose to take this approach in recognition that an emission trading scheme does not provide strong incentives for energy efficiency, particularly in early years.

5. Greenhouse Gas Emission Reduction Measures

Key Findings

- New investment in electricity generation will occur within a carbon-constrained environment. All States and Territories have committed to long-term emission reduction targets. The Commonwealth Government has promised to establish a long-term emission reduction target in 2008.
- To achieve the long-term target, significant change in the way we generate and use electricity will be required across the National Electricity Market.
- Australia inevitably will have a national emissions trading scheme, commencing no later than 2012. This will allow the market to determine the carbon price within the overall abatement targets.
- Uncertainty over the key design elements of a national emissions trading scheme is delaying necessary investment in new generation, including low emission technologies development.
- The Commonwealth Government should give regulatory certainty by bringing forward the timetable for establishing an emissions trading scheme. At a minimum it should resolve and announce the following key parameters:
- the national greenhouse gas reduction target and short term caps and associated penalties
- the basis for allocating emissions permits.
- Renewable and low-emission target schemes, such as the NSW Renewable Energy Target will help to accelerate the use of technologies needed to meet long-term emission reduction goals, before and in the early years of an emissions trading scheme.

5.1 Introduction

A critical issue for potential investors in new generation is the nature and impact of climate change policies over the lifetime of their investment. This was raised in almost every submission to the Inquiry by stakeholders across the board. This chapter identifies and discusses the nature and timing of possible measures, including policy and economic instruments, which can help reduce greenhouse gas emissions.

The Inquiry considers it inevitable that Australia will have a carbon price – that is, a cost that market participants must pay for emitting (or consuming a product that has caused the emission of) greenhouse gases. The carbon price will follow the introduction of a domestic emissions trading scheme,[1] which will allow the market to determine an efficient carbon price within the overall abatement targets set by government.

The establishment of a carbon price is integral to driving technological and behavioural change. It would make the cost of emissions an explicit component of the price of electricity, so that the emissions produced by a particular generation technology become a factor affecting the viability of the investment (along with other costs such as capital expenditure and fuel). Generation technologies that produce relatively few emissions per unit of electricity will experience lower carbon costs. Conversely, technologies that are emissions-intensive will experience relatively high carbon costs, adversely affecting their commercial viability.

At this time, it is difficult, if not impossible, to predict what the market-determined carbon price might be over the life-cycle of a new power plant. This is because key parameters of an emissions trading scheme remain uncertain.

The most important parameter in establishing the carbon price is the size of the abatement task. The future carbon price will be determined by the long-term emissions reduction targets set by government, and the annual constraints imposed on actual emissions (the 'caps'). Tighter targets and caps will increase the cost of emission permits (the carbon price).

[1] Australian Government, *Australia's Climate Change Policy*, July 2007

In this chapter, section 5.2 discusses greenhouse gas emission targets, trading schemes and other climate change policies. Section 5.3 outlines current carbon price modelling while section 5.4 discusses the impact on the carbon price on investment and customers demand for electricity. A carbon price may influence the level of demand for electricity, simply by increasing the cost of electricity to consumers. Chapter 3 considers the set of baseload technology options available to investors. Energy efficiency measures are discussed in Chapter 4.

Appendix 5.1 reviews greenhouse gas reduction policy in Australia, whilst Appendix 5.2 considers international policy developments.

5.2 Greenhouse Gas Emission Reduction Policies

What policies are already in place?

Targets

In June 2005, New South Wales was the first jurisdiction in Australia to announce economy-wide greenhouse gas emission targets. The targets are included in the State Plan (Priority E3).

The NSW targets are:

- a 60 per cent reduction on 2000 greenhouse gas emission levels by 2050
- a return to 2000 greenhouse gas emission levels by 2025.

Other jurisdictions have adopted similar long-term targets and these are detailed in Appendix 5.1[2].

The Commonwealth Government has committed to the introduction of a national emissions trading scheme with long run and annual caps.

[2] Note that the Federal Opposition leader has also adopted a long term target of a 60% reduction on 2000 levels by 2050. See, for example, media statement of 3rd July 2007 which states "Labor is committed to cutting Australia's greenhouse gas emissions by 60 per cent of 2000 levels by 2050…" (http://www.alp.org.au/media).

First Ministers of all States and Territories have agreed through the Council of Australian Federation that 'a national emission trading scheme should place Australia on a path towards achieving a 60 per cent cut in national emissions by 2050 compared to 2000 levels.'[3]

General emission reduction targets, such as a 60 per cent reduction on 2000 levels by 2050, are an economy wide goal. A national emissions trading scheme would be the major policy tool used to achieve these reductions. However, it would not be the only policy measure. For example, if an emissions trading scheme, targeting a 60 per cent reduction from 2000 levels in line with the economy wide target, was to cover sectors that account for 70 per cent of greenhouse gas emissions in Australia, then other policy measures would still be required to meet the economy wide target as otherwise 30 per cent of emissions would continue without any level of abatement.

This target is an economy wide target, and not a target for individual sectors such as electricity or transport. Some sectors may bear more than their pro-rata share of emission reductions. This may occur as the market may source the least-cost abatement options regardless of which sector it occurs in[4]. For example, some stakeholders have modelled scenarios which have the electricity sector achieving a reduction that is greater than 60 per cent, as they believe that the electricity sector could provide relatively low-cost abatement options. On the other hand, some sectors may have relatively expensive abatement opportunities and an emission trading scheme by itself may not drive much emission reductions in that particular sector.

Emissions trading schemes

Australia is already host to the second largest mandatory greenhouse gas emissions trading scheme in the world, the NSW Greenhouse Gas Reduction Scheme (GGAS), which is an electricity focussed scheme, that has led to greenhouse gas reductions across all jurisdictions in the National Electricity Market.

Two suggested frameworks for a national emissions trading scheme have been developed in Australia: the States and Territories' National Emissions Trading Taskforce (NETT) proposal[5] and the Prime Minister's Task Group (PM's Task Group) report.[6]

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[3] All First Ministers adopted this target at the 12 April 2007 meeting of the Council for the Australian Federation (CAF) in Canberra. See p3 of corresponding communiqué.

[4] Depending on the policy settings, for example if offsets are allowed.

[5] National Emissions Trading Taskforce, *Possible Design for a National Greenhouse Gas Emissions Trading Scheme,* 2006

[6] Department of Prime Minister and Cabinet, Prime Ministerial Task Group on Emissions Trading, *Report of the Task Group on Emissions Trading,* 2007. The Prime Minister has generally endorsed the findings of this report through *Australia's Climate Change Policy* released on 17 July 2007.

The Commonwealth has announced that there will be a national emissions trading scheme starting by 2012.

The Inquiry considers emissions trading to be a practical, flexible and relatively low cost means of achieving a greenhouse gas reduction target. The strength of an emission trading scheme is that it is technology neutral – it allows the market to seek out the lowest cost means of achieving a particular emission cap.

The most common form of emissions trading is a cap and trade system, such as that used by the European Union Emissions Trading Scheme (EU ETS). The key features of a cap and trade model are that:

- emissions are capped at some level in each period
- permits to emit greenhouse gases are issued for each period
- participants can trade these permits among themselves
- there is a penalty for non-compliance which underpins a value for emissions[7].

Firms will pay for permits if their internal costs of abatement are higher than the price of permits. Other firms would be willing to sell permits if the revenue they receive from selling permits exceeds the profits from using the permits. Trading of permits also leads to participants innovating and developing emission abatement options that were not envisaged by governments when the scheme was initially designed.

It is important to emphasise that the price of permits is not set by government. The government will set the quantity of permits available, usually expressed in terms of tonnes of carbon dioxide equivalent (CO_2-e) and will let the market determine the price. However, government can set a penalty which acts as a ceiling on compliance costs.

[7] This description borrows heavily from National Emissions Trading Taskforce, op cit, v.

If the government wanted to control the price of emissions absolutely then it could implement a carbon tax. As government cannot set both the price and quantity of emissions, the consensus emerging is that controlling quantity, as under a cap and trade system, has the highest likelihood of achieving an emission reduction target.[8] Further, as other schemes across the world, such as the EU ETS are also based on a cap and trade mechanism, adopting such a scheme design should better facilitate regional and international linking in the future. These benefits were recognised in Epuron's submission which proposed 'implement internationally-consistent carbon pricing schemes in NSW'[9]. Almost all other submissions to the Inquiry were focussed on the benefits of having a nationally consistent emissions trading scheme.

Example: How Tradable Permits Minimise Abatement Costs

There are two firms, Firm A and Firm B. Each emits 20 tonnes of carbon dioxide equivalent (t CO_2-e) per year, so that 40t CO_2-e are emitted annually between them. The government wishes to reduce the total annual carbon emissions of these two firms by 10t CO_2-e, to 30t CO_2-e. One, seemingly fair, possibility would be to require both firms to reduce their emissions in equal proportions, i.e. 5t CO_2-e each. However, this solution will only be in both parties interests if they both face identical emission reduction costs.

Suppose it costs Firm A $100/t CO_2-e to reduce its emissions and that it costs $50/t CO_2-e for Firm B. If both were to reduce their emissions by 5 t CO_2-e, the total cost would be $500 for Firm A and $250 for Firm B: $750 in aggregate.

Assume that the government issues permits to emit carbon to the value of 30t CO_2-e (with 1 permit = 1t CO_2-e), and allocates them equally between the two firms. As long as the price of permits was below $100/t CO_2-e, Firm A would purchase permits rather than take the more expensive option of reducing emissions. Provided the price was above $50/t CO_2-e, Firm B would stand to gain financially by selling permits and making a corresponding reduction in its emissions.

Assume the market price was $70/t CO2-e. Firm A would purchase five permits at a total cost of $350 and need undertake no abatement of its emissions. Firm B would sell five permits at a total benefit of $350, but must reduce emissions by a total of 10t CO2-e. The latter would cost Firm B $500. Thus, after trading, the cost of compliance for Firm A is $350 and for Firm B it is $150. The total cost of meeting the target ($500), therefore, has been reduced through trading because of differences in emission abatement costs between the two firms.

[8] The two economic instruments, emissions trading and a carbon tax give, in theory at least, equivalent results. In practice, with unknown costs of emission abatement, they can give very different outcomes. Refer to Perman et al, Natural Resource and Environmental economics (3rd ed.), Pearson Education, 2003, pp. 254-256

[9] Epuron submission, p2.

Key design features of a National Emissions Trading Scheme

The States and Territories established the NETT in January 2004. The NETT published a detailed design framework in August 2006, *Possible Design for a National Greenhouse Gas Emissions Trading Scheme.*

The PM's Task Group was formed in December 2006 and reported on 1 June 2007. Its design largely followed the proposals of the NETT.

The Commonwealth Government formally responded to the PM's Task Group report on 17 July 2007 when it issued *Australia's Climate Change Policy*.[10] Through this policy the Commonwealth endorsed the need for an emission trading scheme as the primary mechanism for achieving greenhouse gas reductions in Australia.

This policy also endorsed the key design features of the emission trading system set out in the PM's Task Group report.

Key features

Start date: no later than 2012, although the 'objective is to be in a position to commence trading in 2011.'[11]

Type of scheme: cap and trade mechanism.

Coverage: 'maximum practical coverage of all sources and sinks'.[12] Initially, this will cover approximately 70 per cent of greenhouse gas emissions in Australia, including the electricity generation, other stationary energy, fugitive emissions, industrial process emissions and transport. Agriculture and land use will initially be excluded from the scheme though these sectors should be included once practical issues are resolved. The feasibility of including other small sectors such as waste will be investigated.

Offsets: recognition of a wide range of offsets, domestically and internationally. Domestic forestry and agriculture could be important sources of offsets in the early years whilst they are not covered sectors.

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[10] Commonwealth of Australia, *Australia's Climate Change Policy*, 2007

[11] Ibid. p35-36

[12] Ibid. p36

Target: announce a long term aspirational goal in 2008. Short term annual caps for the period until 2020 will be announced in 2010[13].

Emissions cap trajectory: a gradual reduction in annual emissions permits to allow a smooth transition for the economy.

Period cap set for: firm caps set at scheme start until 2020. A cap range set for the period 2020-2030. Caps would be adjusted on a rolling basis (as part of a five-yearly review) to provide greater market certainty.

Penalty (emission fee): This will be set on a rolling basis above estimated market permit prices to ensure scheme compliance; no make good provision for failure to comply. This will initially be set at a low level to act as a "safety valve" to limit unanticipated costs to the economy and to business.

Permits: a mixture of free allocation and auctioning of single-year dated emission permits:

- Disproportionately affected businesses: 'up-front, once-and-for-all, free allocation of permits as compensation to existing businesses identified as likely to suffer a disproportionate loss of value due to the introduction of a carbon price'[14]
- Trade exposed, emissions intensive industries: compensation through free allocation for the 'carbon-related exposures of existing and new investments in trade-exposed, emissions-intensive industries while key international competitors do not face similar carbon constraints'[15]
- Periodic auctioning of remaining permits
- Unlimited banking of permits to encourage early abatement.

Linking: capacity, over time, to link to other comparable national and regional schemes.

[13] *Australia's Climate Change Policy* did not state a specific date for the announcement of short terms caps. However, as the policy generally endorsed the PM's Task Group report which suggested 2010 (op cit, vi, p144), this date has been assumed.

[14] Ibid. p36. The PM has since stated that compensation for firms adversely affected by his proposed emissions trading scheme would apply to assets held on June 3, 2007. The Australian Financial Review, 14 August 2007, "It's 2020 vision for clean coal"

[15] Ibid. p37

From a review of submissions to the Inquiry it is clear that one of the key design features of the national emissions trading scheme is whether or not it is appropriate to allocate free permits to trade-exposed and disproportionately affected businesses.

The NSW Government has stated that GGAS will end once a national emissions trading scheme is implemented. This will require appropriate transitionary measures. The need for transitionary measures was raised by various submissions to the Inquiry.

Remaining Uncertainties

Although the Commonwealth has outlined some design elements of a national emissions trading scheme, the most crucial information which will affect future investment decisions is still highly uncertain. This includes the long-term targets of a domestic emissions trading scheme (including the short term caps and associated penalties) and the basis of permit allocation.

As discussed in Chapter 7, the lack of clarity over these key design elements could delay necessary investment in new generation, including the development of low emission technologies.

The Inquiry believes greater regulatory certainty is necessary and the timetable for establishing the national emissions trading scheme must be brought forward. At a minimum the Commonwealth Government should resolve and announce the following key policy parameters:

- the economy-wide greenhouse reduction target and short term caps and associated penalties
- the criteria on which emissions permits will be allocated.

Submissions to the Inquiry are unanimous that investment in baseload generation will be delayed by uncertainty around a national emissions trading scheme. The proposed national emissions trading scheme will contain a mix of auctioned and freely allocated permits. The number of permits which are allocated will directly affect the supply of permits available and therefore the carbon price. Market participants have stated they require clarity, as soon as possible, about the details of this allocation process.

An up-front, once-off free allocation of permits will be made to those firms that are identified as likely to suffer a disproportionate loss of value due to the introduction of an emissions trading scheme. Regarding the electricity sector, this is likely to include existing emitters which are adversely affected by the scheme (e.g. coal-fired and gas-fired generators). The basic rationale for this allocation is to compensate for investments made in good faith prior to notice of changes to government policy to achieve greenhouse gas reductions.

The PM's Task Group report proposed that the cut-off for eligibility for compensation to existing generators should be the announcement of the Commonwealth's intention to proceed with emissions trading, as subsequent investment decisions would be taken in the knowledge of the impending introduction of a carbon price. However, the PM's Task Group did not suggest criteria as to what constituted an 'investment decision'.

The rationale for setting an early cut-off date is that it could lead to an excessive short term investment in high emission intensity plant, which would defeat the whole purpose of the trading scheme and make later reductions far more costly. Conversely, the rationale for setting a later cut-off date is that until there is full certainty of the details of the scheme, in particular how permits will be allocated, investors will defer projects until certainty is provided. [See section 5.4 for a discussion of how carbon price will impact both generation technology choice and the appropriate timing for new generation investment.] This could create a period where major infrastructure projects are delayed awaiting policy certainty. Any delay in investment decision-making would increase the likelihood of a shortfall in electricity supply in New South Wales over the coming years which would be detrimental to the Australian economy.

A second group of participants would also receive a free allocation of permits. These are trade-exposed energy intensive industries, such as steel and aluminium producers, which are adversely affected by the imposition of an emissions trading scheme. The rationale for this allocation process is due to the overseas competitors of these Australian exporting industries not being subject to an equivalent carbon price. This permit allocation would be made annually[16] and compensate for the increased price of electricity due to the emissions trading scheme.

It is recognised that the allocation process would necessarily involve estimations of future impacts. However, the early resolution of allocation issues is desirable as the allocation framework will determine the number of permits available for auction and therefore affect the carbon price.

[16] The NETT suggested annually. The PM's Task Group's report suggests a five-yearly upfront allocation with review.

Other Climate Change Policies

There are a range of other policy measures that Governments may use to address greenhouse gas emissions. These include renewable and low emission energy targets, energy efficiency schemes and research, development and deployment funds, which are all currently being used in Australia.

Some submissions consider that there continues to be a need for these measures in order to accelerate the development and implementation of low carbon emission technologies ahead of market outcomes driven solely by a carbon price. Other submissions supported the Commonwealth view that Australia should rely solely on a national emissions trading scheme and wind up the existing State and Territory based schemes.

For a more detailed discussion of the current status and future prospects for these policies refer to Appendix 5.1.

Renewable and Low Emission Targets

There are renewable and low emission energy targets that already have a legislative or policy basis to extend out to 2013-14[17] and beyond, these include:

- Commonwealth Mandatory Renewable Energy Target (MRET): legislated out to 2020
- Victorian Renewable Energy Target (VRET): legislated out to 2030
- NSW Renewable Energy Target (NRET): announced to be legislated to 2030[18]
- Other state renewable energy targets such as in South Australia, Queensland, Western Australia and the Australian Capital Territory.

There is a possibility that the State schemes will evolve into an expanded national scheme. There is also the possibility of the Commonwealth Government attempting to abolish these schemes, as indicated in the PM's Task Group Report.[19] The continuation of renewable energy targets has been supported by a number of stakeholders. Auswind is actively pursuing an expanded national renewable energy scheme with the Commonwealth Government and several other submissions have also suggested it would be more efficient to roll the various renewable schemes into one national scheme.

[17] The Inquiry has used 2013-14 as the reference year as this is around the time that a new baseload generator is required in NSW.

[18] The *Renewable Energy (New South Wales) Bill 2007* was introduced into Parliament on 27 June 2007.

[19] Prime Minister's Task Group Report, p.137

Renewable energy targets may not be the most economically efficient solution where the sole objective is the lowest cost form of emissions reduction in the short term. However, their purpose is to accelerate the deployment of the very low emission technologies that help meet long-term emission reduction goals. It is possible that in the early years of the new emissions trading scheme that permit prices will be somewhat volatile as participants learn about the market and how they should be participating in it. This problem should progressively disappear as the emissions trading scheme matures.

Queensland 18% Gas Scheme

The Queensland Gas scheme provides incentives to build new gas-fired generation capacity by requiring a certain proportion[20] of Queensland's electricity supply to be sourced from gas-fired generation. Eligible fuels are natural gas, coal seam gas (including waste coal mine gas), liquefied petroleum gas and waste gases associated with conventional petroleum refining. The scheme may also be phased out once a national emissions trading scheme is implemented, so long as appropriate transitional arrangements can be determined.

Submissions from both AGL and Sydney Gas recommended the NSW Government introduce a scheme similar to the Queensland gas scheme. The Inquiry believes that an emissions trading scheme would fulfil the same policy objective to such a gas scheme by providing appropriate signals to the gas industry for efficient investment and therefore does not support this proposal.

Energy Efficiency Measures

Energy efficiency measures can contribute to emission reductions as they help to curtail growth in electricity demand. Energy efficiency measures are discussed in Chapter 4.

Research, Development and Deployment Funds

Research, development and deployment funds promote research into low emission technology, and accelerate its commercial application. These schemes can lower the cost of meeting emission targets in the future via technology change. Further details are provided in Appendix 5.1.

[20] Introduced at 13% but announced by the Queensland Government in June 2007 to increase to 18% by 2020. See Queensland Government, *Climate Smart*, June 2007, p.viii

Carbon Tax

Currently, no jurisdictions in Australia use a carbon tax although it is being used in some European countries. As discussed earlier in this section, a carbon tax and an emissions trading scheme broadly fulfil the same policy objective, but with the government controlling price and quantity respectively. Given the momentum behind designing an emissions trading scheme the Inquiry sees no reason for Australia to switch course and opt for a carbon tax. It is possible that Australia might, in the future, choose to adopt a carbon tax for sectors not covered by the emissions trading scheme.

As noted above, the level at which a penalty is set under an emissions trading scheme will effectively act as the maximum cost of compliance. If this penalty is set relatively low, it could in effect act as a hybrid carbon tax / emissions trading scheme.

Emissions Standards

All jurisdictions have planning and environmental controls on emissions from power stations regarding air quality. However, emissions standards can also be used more directly to fulfil a greenhouse gas reduction policy objective. For example California has recently approved regulations to prohibit the State's publicly owned utilities from entering into long term financial commitments with plants that exceed 1,100 pounds (500kg) of CO_2-e per MWh. This emissions standard effectively precludes all coal-fired baseload technologies that do not include carbon capture[21].

In the past, the NSW Government has refused an application for the development of a power plant that had unacceptably high greenhouse gas impacts. However, the Inquiry considers an emissions standard is another mechanism to achieve the same policy objective as an emissions trading scheme. The financial incentives driven by an emissions trading scheme will provide appropriate incentives to the market to ensure cost-effective and emission efficient technology is invested in without the use of direct output control standards. The Inquiry notes that the actual annual emissions cap (as opposed to the long run target) has the potential to achieve the same investment outcome as this Californian style standard.

[21] see www.energy.ca.gov/releases/2007

5.3 Carbon Price Modelling

When an emissions trading scheme is introduced in Australia, the future cost of generating electricity is likely to be strongly influenced by the price of carbon. Businesses in both the public and private sector will need to model the carbon price as part of an evaluation of generation investment.

Several recent studies have attempted to estimate the possible future price of carbon that may result from the introduction of an emissions trading scheme. These studies have considered a range of scenarios. The modelling produces different carbon price outcomes, depending on the set of assumptions underlying each scenario.

Given the state of knowledge of the design of a future national emissions trading scheme, models must make a number of assumptions. This explains the wide range of possible carbon prices being reported from these modelling exercises. The assumptions include:

- the cost and availability of new low emission technologies, such as carbon capture and storage (CCS) and renewable technologies
- the cost and availability of offsets, such as forest sinks
- changes in demand growth rates (which themselves incorporate assumptions about future economic growth, demographic change and consumer behaviour)
- the level of energy efficiency improvements (i.e. the models, to varying degrees, already provide for 'autonomous' energy efficiency improvements)
- foresight and banking levels (i.e. the likely behaviour of liable parties).

Besides these general assumptions, the main drivers of the variations in the outcomes of the studies include differences in:

- the overall emissions reduction target
- the rate of emissions reduction (trajectory) required
- the coverage of included sectors
- the availability and price of a variety of technologies
- the availability and price of various emissions offsets.

The Inquiry recognises that the call for greater certainty is so that market participants can improve their modelling of likely price outcomes and so have more certainty about the economic viability of their proposed investments.

5.4 Carbon Price Impact

What will be the impact on investment?

The carbon price, and uncertainty over the future level of carbon prices, can have a significant impact on the choice of baseload generation technology. Chapter 3 has considered the different baseload generation options available and concluded that the most economically viable options to meet NSW requirements are either coal or gas-fired generators. Consequently, this section focuses on the impact of carbon prices on these two generation technology options:

- combined cycle gas turbines – moderate capital cost and moderate fuel costs, and therefore suitable for intermediate load
- pulverized fuel coal-fired power stations – high capital costs but low fuel costs, and therefore suitable for baseload.

Both of these plant types are technically able to run at high capacity factors, i.e. they can physically run almost continuously throughout the year, but coal-fired generators' lower fuel cost makes them more cost-effective for continuous operation than gas.

Assuming that there is adequate gas available, a high enough price on carbon could rebalance the national electricity market dispatch order of gas and coal-fired generators and ultimately make new combined cycle gas turbines more cost-effective to build than coal-fired generators. It is apparent that, in the absence of other constraints, the carbon cost over the forecast life of a generation investment will influence the generation technology choice.

Origin Energy, Transfield and the APA Group, in their submissions, all provided views on the impact that different levels of the carbon price would have on the economic viability of gas vis-à-vis coal-fired generation. This again points to the need for certainty on the future form of a national emissions trading scheme. Without this certainty, investors in new generation will have difficulty modelling the impact of emissions policy on their investment decisions.

Impact of Carbon Capture and Storage Technology on NSW Greenhouse Gas Emissions

Submissions to the Inquiry have divergent views on the policy framework that NSW Government should apply to future generation. Many submissions believe that the Government should remain silent on the preferred technology and let the private sector decide. However others see a legitimate role for Government in setting emissions standards that would at a minimum prevent investment in coal-fired generation, claiming without this action State emission targets will not be achieved.

The Inquiry examined CO_2 projections under both intensive gas-fired and coal-fired scenarios:

- Install 2000 MW of CCGT from 2013 then USC coal-fired plant from 2018
- Install USC coal-fired plant from 2014.

No carbon capture is assumed for CCGTs because of their small scale and geographic dispersion. Whilst carbon capture technology should be applicable to the scale of a CCGT plant the costs of collecting the captured gas and transporting it to a storage site increase substantially when the carbon is sourced from a range of sites.

The Inquiry found that the emissions intensity of the NSW generators declines over time because new coal-fired plant, which is both environmentally and commercially more efficient, displaces less efficient old coal-fired generation. The effect is more marked if CCGT substitutes old coal.

Figure 5.1: CO_2 Emissions Intensity Projections for NSW Generation

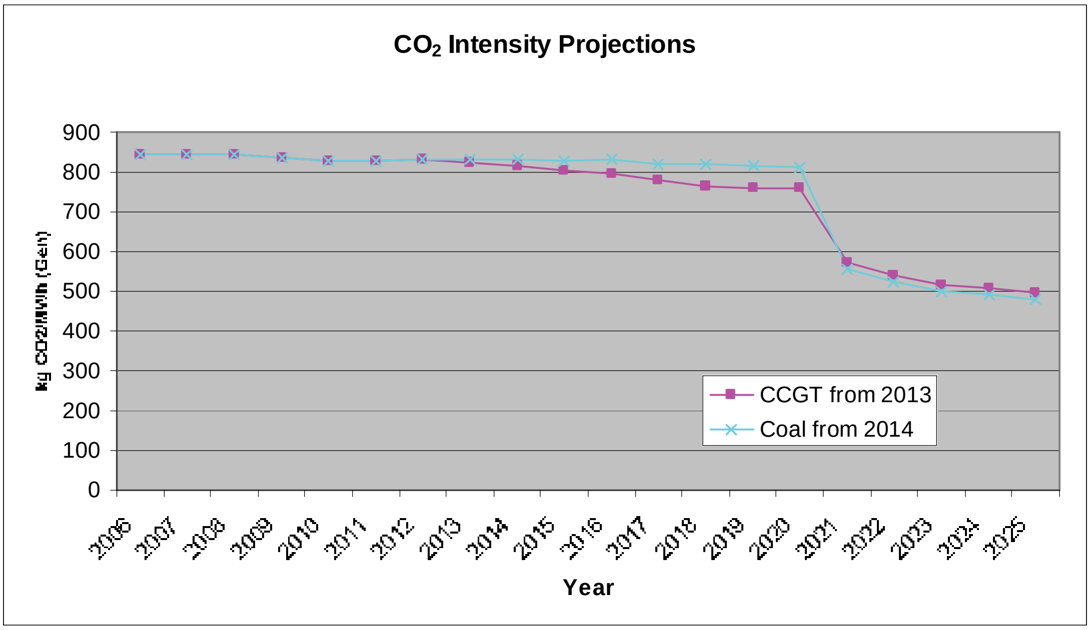

Figure 5.1, which measures $kgCO_2/MWh$ shows a reduction in emissions per MWh of energy generated throughout the period, this highlights the substitution effect that both new coal or CCGT will have on old coal and the resultant reduction in emissions intensity. Note that Figure 5.1 uses MWh generated which results in lower emissions intensity than if MWh sent out were used. Power stations typically use around 5 per cent of the energy generated to operate, however for a power station with CCS technology this is currently estimated to increase to around 30 per cent.

Whilst the emissions intensity declines under both scenarios total emissions continues to climb driven by increasing consumption of energy. The reduction in emissions intensity is insufficient to offset the increase in electricity consumed although it does moderate the effect.

The Inquiry then considered the impact that CCS might have on the combined NSW generation emissions if introduced beyond 2020. The Inquiry found that a low emission technology like CCS could have a significant effect on the total level of emissions and on the emissions intensity of the NSW generators.

Provided CCS is retrofitted to new coal-fired generators both scenarios could meet NSW energy requirements and its 2025 emissions target. The coal only scenario also requires retrofitting one existing generator. The CCGT then coal scenario requires retrofitting two existing coal generators.

Figure 5.2: Total CO_2 Projections for NSW Generation

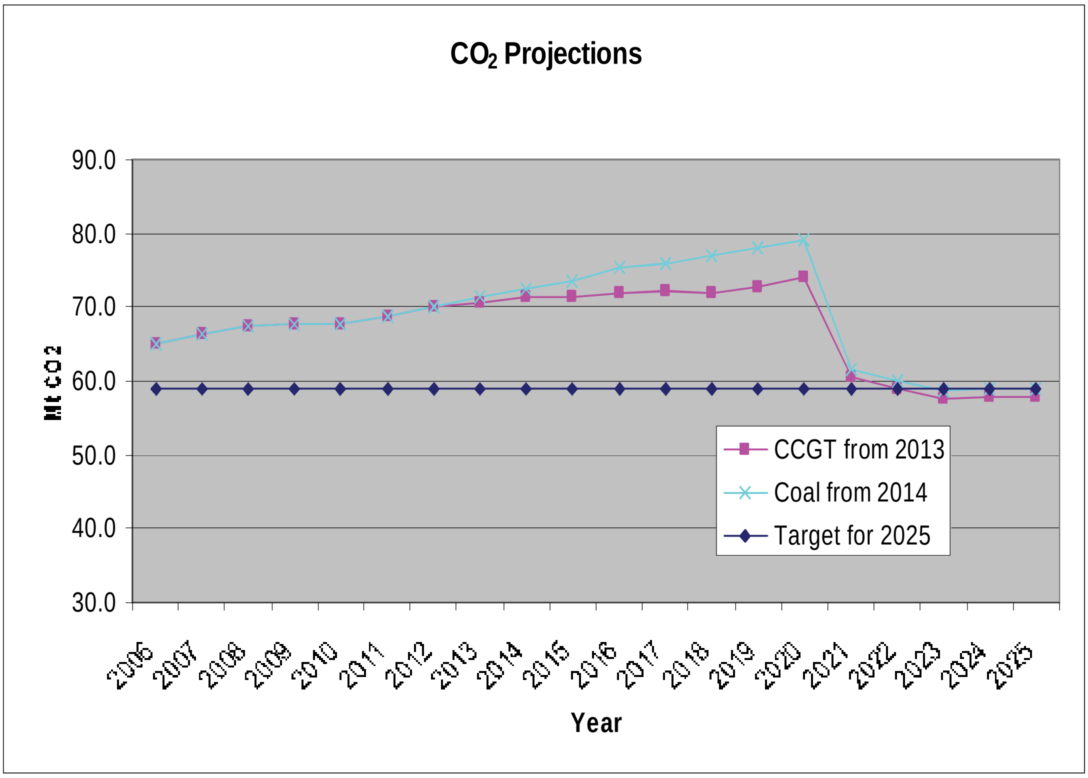

Figure 5.2, measuring Mt /CO_2, shows a steady increase in the absolute level of emissions driven by increasing consumption of energy up until the introduction of CCS irrespective of whether the next investment is CCGT or coal-fired.

CCS technologies are being actively researched and developed but it is unlikely that they will be available at utility scale for incorporation in baseload plants until beyond 2020. Any new coal-fired generation that can be built to provide for retrofitting of carbon capture plant will facilitate utilisation of CCS at such time that the technology becomes available.

What will be the impact on energy demand?

What impact the future carbon price might have on customers demand for energy is also a key question for investors in new generation assets. Any carbon price will ultimately flow through to the retail electricity prices that customers pay and this will reduce their level of consumption.

NSW customers already face a carbon cost in the retail price they pay for electricity. Both GGAS and MRET impose carbon costs on customers and any impact these programmes already have on customers demand for electricity is reflected in current demand data. From 2008 the NSW Renewable Energy Target will also impose a modest cost on electricity customers.

NSW policy is that GGAS will cease, with appropriate transitional arrangements, when a national emissions trading scheme is introduced. Whilst GGAS costs will fall away it is highly likely that carbon permits will cost substantially more than the $3/MWh that IPART has estimated the existing policies have cost customers over the last three years[22].

As the Commonwealth Government is yet to determine key details of the national emissions trading scheme that it has committed to, the carbon price and its impact on customers demand for electricity is also unknown. A very high carbon price could lead to a demand response that is sufficient to delay the optimal time to build new generation. However, all signals to date have been that the Commonwealth Government favours setting a relatively high emissions cap (i.e. less onerous) in the early years. This creates difficulties for investors in new generation assets as a tighter than expected cap could result in inappropriately early investment and a poor financial return which may endanger the financial viability of the entire project.

[22] Independent Pricing and Regulatory Tribunal, *NSW Regulated Retail Tariffs 2004/05 to 2006/07: Final Report and Determination, June 2004, p39.*

6. Public Versus Private Sector Investment

Key Findings

- Historically, the NSW Government has ensured the State's supply of generation through ownership of, and investment in, power stations.
- The energy market reforms of the 1990s have established a national and competitive energy market governed by a tested regulatory framework. The success of these reforms means the Government no longer needs to own electricity businesses to ensure security of supply.
- The National Electricity Market (NEM) provides a market that is efficient and protects consumers regarding price, quality, reliability and security of electricity supply.
- Government ownership of electricity businesses operating in the competitive sectors of the industry neither increases nor decreases the State's ability to ensure price, social and environmental outcomes are achieved from the electricity industry.
- Should the NSW Government choose to continue to own most of the State's electricity industry, the State will almost certainly have to both fund the next tranche of baseload generation in New South Wales and invest further in the State-owned energy corporations. There is no sustainable half way house. If Government continues to own businesses operating in the competitive energy market, it needs to accept that these businesses will have to pursue business strategies and investments across the NEM that will allow them to be successful.
- Investment in baseload capacity is but one example of the type of investments that Government would need to fund. The cost of new investment in generation capacity in New South Wales over the next 10 to 15 years is expected to be in the vicinity of $7 billion to $8 billion.

Key Findings (cont)

- The Government owned retail businesses will struggle to remain viable without significant additional capital to allow them to adopt a more vertically and horizontally integrated business model. The potential cost of doing so is in the range of $2 billion to $3 billion over the same period.
- Further, the Inquiry believes Government may be exposed to investing in the order of $3 billion to $4 billion over the next 15 years to retro-fit some existing power stations with carbon reduction technologies.
- While these investments may earn a return, the NSW Government would need to accept that it has less choice over how its limited capital is allocated to meet State Plan objectives and be prepared to make adjustments elsewhere in its capital program and State Budget to account for the increased business risk that such investment entails.
- Alternatively, divesting the retail and generation interests to the private sector would mitigate the need for public funding of the investment in these businesses and would realise proceeds otherwise unavailable to the Government.
- The combined impact of both the divestment of generation and retail and the avoidance of new generation investment means that total State net debt would be up to $26 billion lower in 2020 compared to a 'retain and invest' scenario. This would significantly improve the State's fiscal position and the Government's ability to meet its State Plan objectives.
- The State's business profile and credit rating will benefit from the removal of 'high risk' generation and retail assets from its balance sheet.
- In summary, the Inquiry considers private sector investment will meet the State's emerging generation needs while allowing the Government to achieve its energy and environmental policy goals, maintain the State's credit rating and improve its ability to deliver State Plan objectives.

6.1 Introduction

The fourth term of reference of the Inquiry is to determine the conditions needed to ensure investment in emerging generation, consistent with maintaining the NSW AAA credit rating.

The Inquiry sees this term of reference as establishing whether the NSW Government's responsibility to ensure a competitively priced and reliable supply of electricity for the State is consistent with its stated preference for the private sector to fund the State's emerging generation needs.

In May 2007 the NSW Premier stated 'It is not my preference, or the preference of this Government to use public funds to build new power stations with such funding better used elsewhere such as hospitals and schools'[1]

This sentiment has also been expressed in the recent NSW Infrastructure report to the Council of Australian Governments (COAG):

'The NSW Government recognises the importance of adequate, reliable electricity supplies to the NSW economy and to the living standards of NSW citizens'... 'The NSW Government preference is that the private sector undertakes investment in new electricity generation capacity. If the private sector investment is not forthcoming and the Government perceives that there are risks that supply demand imbalances may result in supply shortfalls, then the Government-owned business may invest in new capacity to meet that demand. The NSW Government will not allow NSW businesses and residences to suffer from blackouts and supply shortfalls'.[2]

Electricity supply is an essential service, and the Inquiry recognises the Government's responsibility to see that there is a reliable, secure and competitively priced supply of electricity. Historically, Governments have met this responsibility through building and owning power stations, and to a lesser extent retail businesses.

Since the last significant investment in generation capacity in New South Wales,[3] the NEM has been established. As reflected in submissions, market participants are confident that the electricity market now supports private investment.

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[1] News release issued by the Premier of New South Wales, the Honorable Morris Iemma, 9 May 2007

[2] NSW Treasury, *New South Wales Government Five Yearly Infrastructure Report to the Council of Australian Governments*, January 2007, p.92-93

[3] Units 1 and 2 of the Mount Piper Power Station commissioned in 1993 and 1992 respectively

Consequently, the Inquiry has considered:

- whether Government ownership is necessary to ensure reliability of electricity supply;
- whether Government ownership is necessary to ensure the market achieves appropriate price, social and environmental outcomes;
- the effectiveness of the National Energy Market (NEM) in delivering a reliable and least cost electricity supply; and
- the capacity of Government to maintain a reliable supply of electricity to the State in a manner consistent with maintaining the State's AAA credit rating.

6.2 Government Ownership

Public Trading Enterprises (PTEs) and State Owned Corporations (SOCs) allow the Government to be involved in a business-like manner in areas where:

- the private sector is unlikely or unable to deliver the required products or services
- the community considers it appropriate that Government should own a business, for example, one that operates as a natural monopoly.

Is Government ownership necessary for reliable supply?

For the electricity industry it is important to distinguish between PTE/SOCs that are regulated monopolies and those that operate in competitive markets. While the arguments above may point to electricity distribution and transmission infrastructure being areas with a rationale for Government ownership, the Inquiry does not believe this rationale applies to the electricity retail and generation businesses that operate in the competitive part of the electricity supply chain.

Historically, the NSW Government, similar to other Australian State governments, has ensured security of supply by building and owning power stations. Prior to the creation of the NEM, the east coast electricity industry was characterized by:

- vertically-integrated government-owned generation and transmission monopolies
- regionally-based distribution business, responsible for both distribution system operations and maintenance, and retail electricity supply
- centralised, coordinated planning of generation and transmission system development
- prices at all levels of the electricity supply chain set via regulation, there was no market to provide price signals for investment in new capacity.

The industry changes that enabled the NEM to be successfully established left the NSW Government owning businesses which:

- own the State's high-voltage transmission and low-voltage electricity distribution networks
- own over 95 per cent of the State's installed generation capacity
- supply the majority of the State's retail sales of electricity.

The NSW Government also:

- is part of the Ministerial Council of Energy which oversees national energy policy by ensuring the National Electricity Market supports an efficient electricity industry
- has with other States and the Commonwealth supported the establishment of the Australian Energy Market Commission (AEMC) as the independent energy market rule maker
- sets State environmental policies and licence conditions
- sets the terms of reference for retail price tariff determinations
- establishes the land use planning and development approval process for new investments
- sets customer protection and reliability standards to be implemented by energy businesses.

Generation supply and reliability are independently regulated

Owning businesses is not the way the Government ensures there is enough generation capacity. The AEMC is responsible for the market rules which ensure an efficient and responsive National Electricity Market. As the industry evolves the rule change process administered by the AEMC is designed to ensure the market similarly evolves to suit industry and consumer needs.

The National Electricity Market Management Company (NEMMCO) has responsibility for ensuring reliability of supply. NEMMCO uses its Statement of Opportunities and the Annual National Transmission Statement to help the private sector identify new investment opportunities.

New South Wales will continue to be a member of the Ministerial Council on Energy which will continue to ensure that NEMMCO's reserve contracting role is effectively exercised. This function is the primary 'safety net' by which sufficient reserve capacity is maintained as a buffer against spikes in demand or unit outages.

As part of the national regulatory framework a Reliability Panel has been established by the AEMC to monitor, report and review the safety, security and reliability of the national electricity system. This Panel is unaffected by who owns generation and retail businesses.

Is Government ownership necessary for the public's best interest?

The NSW Government owns energy assets (the shareholder function) and overseas policy and regulation of the energy industry (the policy function).

The two roles are kept separate so that private sector businesses are operating in a competitively neutral environment. That is, State Owned Corporations must comply with the same rules and requirements that the private sector must comply with.

The NSW Government's ownership of electricity businesses is controlled by the *Energy Services Corporations Act (NSW) 1995*, the *State Owned Corporations Act (NSW) 1989* and the supporting Commercial Policy framework, under the auspices of the Treasurer.

The NSW Government's electricity policy objectives are achieved through separate legislation such as the *Electricity Supply Act (NSW) 1995*, and the National Electricity Law. Much of this has been, or is in the process of being, harmonised with other jurisdictions to establish a nationally consistent approach to electricity policy. These policy instruments operate under the auspices of the Minister for Energy.

Policy, not ownership achieves price, social and environmental outcomes

The Government's core policy role is to ensure a robust policy and regulatory framework that will deliver an effective and efficient market and appropriate conditions for consumer and environmental protection. Regardless of whether the energy businesses are owned by the Government or the private sector, the regulations and policies imposed by the Government apply equally to both State Owned corporations and private sector organisations.

The NSW Government is currently a driving force behind the National Reform Agenda for energy. A key part of this is harmonising the policy and regulatory frameworks for electricity and gas. For instance the Council of Australian Governments (COAG) recently agreed to implement a national energy market operator - Australian Energy Market Operator. This will bring together the market operators for both electricity and gas and will mean that the two parts of the energy industry are increasingly on an equal footing from a policy and regulatory perspective.

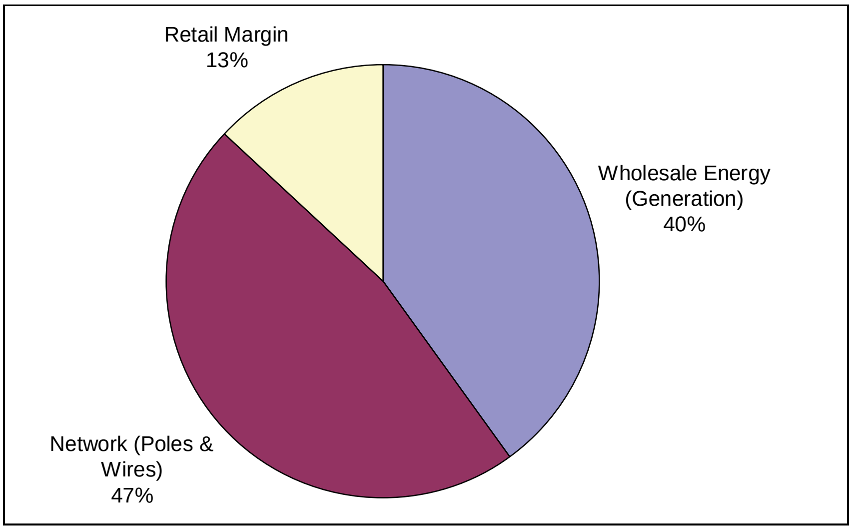
In Australia, the gas industry is largely owned by the private sector. Consumer protection, environmental protection and reliability are still achieved in the gas industry through Government regulation even though the Government does not own these businesses. It is the policy and regulatory functions, which apply similar principles to those used in electricity, that are designed to meet these goals. The businesses operate within the framework established by Government. Increasingly the regulatory frameworks for the two segments (gas and electricity) of the energy industry are being harmonised. This recognises that businesses in the energy industry are becoming integrated energy businesses rather than standalone gas or electricity businesses.

Policy supports price outcomes

The electricity prices paid by customers comprise a number of different charges – a charge for the purchase of electricity from the wholesale market, transportation (transmission and distribution) charges and a retail charge. For households and most small businesses, around 40 per cent of this regulated electricity price is made up of wholesale charges, around 47 per cent is transmission and distribution charges, and around 13 per cent is retail charges. Whether the electricity supply businesses are Government or privately owned is not a factor in determining the level of these charges, or the size of the customer's bill. This is illustrated below in Figure 6.1[4] and each component is discussed in further detail below.

[4] IPART's target regulated electricity retail tariff for a typical small customer in 2010

Figure 6.1: Electricity Value Chain – Regulated Retail Tariff



The size of the generation component of the bill is determined by prices in the wholesale market of the NEM. Wholesale trading in the NEM is a real-time spot market where supply and demand are instantaneously matched through a centrally-coordinated market process. Generators bid to supply the market with specific amounts of electricity at offer prices. Offers are submitted for every five minutes of the day. NEMMCO dispatches the least cost generators into production so that dispatch occurs in a 'rising stack' of price from lowest to highest. The wholesale price is determined by the offer bids of the generators, not their ownership.

Generators' activities in the wholesale market are strongly regulated by national institutions irrespective of whether they are government or privately owned.

Generators operating in the NEM are subject to the economy-wide anti-competitive provisions of the Trade Practices Act administered by the Australian Competition and Consumer Commission (the ACCC). There are heavy fines under the Trade Practices Act if firms engage in anti-competitive behaviour.

In addition, the operation of the NEM is governed by industry-specific legislation comprising the National Electricity Law and the National Electricity Rules. The rules governing the bidding behaviour of generators are particularly strong. There is a $1 million penalty for breaches of the rebidding rules which apply to both companies and the individuals that work for those companies. By comparison, all other civil penalties under the National Electricity Law attract a $20,000 fine for an individual and $100,000 for a company.

The National Electricity Law and the National Electricity Rules are administered and enforced by the Australian Energy Regulator (AER). The AER has a team that monitors bidding and price outcomes on a daily basis. The AER routinely investigates incidents when market prices exceed $5,000 per megawatt hour and has power to investigate where an inadequate reason for generator rebidding is provided to NEMMCO.

NEMMCO which, administers the wholesale market into which generators bid their output, also has powers under the National Electricity Rules to require a generator to dispatch if supply has been withheld and there is a risk of an imbalance between supply and demand which would lead to power interruptions.

While dispatch of existing generators is centrally coordinated, investment in new generators is not. The NEM encourages market participants to decide on the location, type and timing of new investments on the basis of forward electricity prices, as well as any other relevant commercial or regulatory factors such as land use planning. To the extent that the NEM promotes efficient investment decisions it helps to ensure that wholesale prices remain efficient.

The transmission and distribution companies are natural monopolies and their tariffs are regulated by an independent pricing regulator. In the case of the transmission operator, TransGrid, the regulator is the AER. In the case of the distribution businesses, the regulator is currently the Independent Pricing and Regulatory Tribunal (IPART). The AER will assume responsibility for regulating the tariffs charged by the distribution businesses in the near future. Ownership does not affect the regulators' determination of the level of the charges.

There are currently 23 electricity retail businesses licensed to operate in New South Wales. Of these, the three Government owned businesses – EnergyAustralia, Integral Energy and Country Energy – supply approximately 25 per cent of NSW retail load. All licensed retailers, regardless of their ownership, are required to comply with the NSW regulatory framework as set out in NSW legislation.

The retail component of the end user's bill is relatively small. Since January 2002, all electricity customers in New South Wales have been free to compare offers from competing retailers and choose one that best suits their needs. For those customers who have entered the competitive market, the retail charge is determined by competition between retailers for customers and retailers effectiveness in purchasing in the wholesale market. IPART regulates the retail charge for those customers not in the competitive market. In 2005-06 there were over 2.2 million regulated customers in New South Wales who consumed almost 20,000GWh of electricity. There were also just over 920,000 contestable customers who consumed over 50,000GWh of electricity.

Policy achieves social outcomes

The NSW Government has one of the strongest consumer protection frameworks in Australia. This framework recognises that in order to encourage a competitive market, consumers need to have confidence in the market and have access to sound information on the how the market works. It also recognises that electricity is an essential service and that there are some members of the community who have special requirements, such as low income groups and those using life support machines. The Government has specifically sought to address this small group of community.

The consumer protection framework is largely implemented via the Minister for Energy licensing all electricity retailers operating in New South Wales. There are a range of requirements on retailers under the *Electricity Supply Act (NSW) 1995* and associated Regulations, including:

- A requirement to supply all customers who are connected to the grid with power
- Compliance with the Marketing Code of Conduct, that governs everything from what time a marketer can knock on a door to offer a new electricity contract, to the information that the retailer must provide in a contract, and ensuring that there is a cooling off period when a new contract is signed
- Membership of an approved Ombudsman scheme –the Energy and Water Ombudsman, NSW - and abiding by the Ombudsman's rulings
- Allowing customers experiencing financial difficulties to pay by installments
- Very strong disconnection procedures, including preventing disconnection when a matter is before the Ombudsman or customers are on life support equipment.

These consumer protection requirements have been developed by the NSW Government in conjunction with the industry and consumer groups. The Government continues to look for ways to improve the consumer protection framework. For example, in response to an increase in disconnections, the Government implemented new regulations that resulted in the development of a Hardship Charter by all retailers.

The Government also provides direct support for some consumers via rebates. There are three types of rebates – a $112 per year pensioner rebate, a life support rebate which varies depending on the type of life support machine that is required in the home and Energy Account Payment Assistance (EAPA) vouchers of $30. EAPA vouchers are distributed by community welfare organizations such as the Smith Family and Salvation Army and are for customers experiencing a financial crisis. The community welfare organizations may decide to provide several vouchers to a customer.

The total value of the budget funded rebates in New South Wales in 2006-07 were pensioner rebates of $80.37 million, life support rebates of $2.66 million, and EAPA rebates of $7.44 million.

Consumer protection also encompasses the network businesses, through the imposition of reliability standards. The distribution reliability standards are generally State-based, while there are both national and State-based transmission reliability standards.

Policy achieves environmental outcomes

Environmental protection covers a number of areas – climate change, water and air pollution, water consumption from NSW rivers, and planning. These are discussed in detail below.

Climate change should be regulated at the national level via a national emissions trading scheme. However, in the absence of action from the Commonwealth Government, New South Wales has implemented effective and world leading greenhouse regulation on the energy industry.

The *Energy Supply Act (NSW) 1995* establishes the NSW Greenhouse Gas Reduction Scheme (GGAS) which requires all electricity retailers to meet legislated targets for electricity consumed in New South Wales. GGAS is one of the first mandatory trading schemes applied to electricity retailers.

The *Renewable Energy (NSW) Bill 2007* has also been introduced in Parliament, which when passed will establish a renewable energy target of 10 per cent of power consumed in New South Wales must be supplied by renewable generators, increasing to 15 per cent by 2020.

There is also a range of other greenhouse /climate change policies that the Government has applied. Chapter 4 provide details on energy efficiency and demand management programs in New South Wales, including Energy Savings Action Plans, the Climate Change Fund, the Building Sustainability Index (BASIX), the Government Energy Management Program, the National Framework for Energy Efficiency, Minimum Energy Performance Standards and energy labelling. Government commitment to these programs does not depend on ownership of electricity generation or retail businesses.

Power stations and their operations are licensed by the NSW Government, with a particular focus on air and water pollutants. This licensing occurs under the *Protection of the Environment Operations Act (NSW) 1997*, and is administered by the Minister for the Environment and the Department of Environment and Climate Change. This regulates non-greenhouse emissions such as NOx, SOx and particulate matter, and water discharge after it has been used for cooling in the power station.

Like other large water users, a power station's access to water from catchments is regulated. This is regulated under the *Water Management Act (NSW) 2000*, and is administered by the Minister for Water and the Department of Water and Energy.

As with the development of most large infrastructure, new developments require planning approval from the Minister and/or the Department of Planning. Power stations and significant network infrastructure must all receive the appropriate planning approvals.

Government ownership is not necessary to deliver the outcomes government wants

The Inquiry considers that the NSW Government has paid particular attention to the transparent separation of policy and ownership functions. As a consequence, the Government's ownership of businesses operating in the electricity market neither increases nor decreases its ability to implement its energy policy objectives.

The Inquiry concludes that ownership in and of itself does not affect prices in the competitive market segments (generation and contestable retail) or other regulated market segments (transmission, distribution and regulated retail). But to the extent that transferring the State's retail and generation interests to the private sector increases the potential dynamics in the generation and contestable retail sectors there would be a beneficial impact on the price of electricity .

The Inquiry considers that the NSW energy retail market without Government ownership will not:

- affect prices paid by customers as there will continue to be an independently set regulated retail tariffs that small customers can remain on
- restrict the ability of the NSW Government to achieve community and environmental objectives. Policies and regulations such as targeted support for customers facing financial difficulties and regulating the environmental impacts of generation will continue.

It is clear the distinction and separation of these two functions, and the recognition that Government ownership is not essential to achieving price, reliability environmental or social policy outcomes, which underlies the Inquiry's key recommendation.

The affect of government decision making can be seen in the effects of generation investment decisions prior to the creation of the NEM in 1989-1990. The Industry Commission[5] estimated that the excess generation that New South Wales had built had an opportunity cost of $443 million, or $77 per person in New South Wales at that time. In today's dollars this would equate to each NSW citizen paying $130 per annum in either additional taxes or electricity charges to fund this excess capacity.

The Inquiry considers that outcomes similar to those prior to the commencement of the competitive energy market could arise where the State's emerging generation needs were funded by the Government. Under this scenario the Government would be forced to again adopt a central planner approach to generation investment rather than a decision making process under a market-based approach. Any less commercial investment decisions that result from this process will increase the price of electricity charged to NSW customers.

In Victoria it has been argued that privatisation has provided significant benefits both to the Victorian community and economy in general. It is claimed that since privatisation, Victorian energy businesses have shown marked increases in productivity and customer service and that customers have enjoyed lower prices and improved reliability.

'The bottom line is that privatisation has brought substantial benefits over the past decade to the energy sector, Victorian consumers, the State Budget and the wider economy.'[6]

While the Inquiry recognises the difficulties in attributing these benefits purely to privatisation, given the wide range of other determining factors, the Inquiry notes that as set out in Table 6.1 there has been new investment in generation in jurisdictions that have privatised.

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[5] Industry Commission, *Energy Generation and Distribution, Report No. 11*, May 1991, p.38

[6] Access Economics, *Impact on Victoria of the Privatisation of the State's Electricity and Gas Assets.* Prepared for TXU Australia. June 2001, p2.

6.3 Effectiveness of the National Electricity Market in Delivering a Reliable and Efficient Electricity Supply

This issue is considered in detail in the Morgan Stanley report to the Inquiry. The report is Expert Report 3 and its findings are considered in greater detail in later sections.

The National Energy Market is working well

In summary, the Inquiry concurs with the Morgan Stanley's conclusion that the NEM has worked well since its inception in meeting the market objective to 'promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system'.[7]

In terms of investment:

- the market has delivered new investment as set out in Table 6.1, with a substantial amount of this coming from the private sector, particularly in wholly privatised jurisdictions; and
- private sector investment to date has been made largely in peak and intermediate plant, and has been driven by volatility of electricity prices. This investment shows that generation supply does respond efficiently to prices set in the wholesale market.

Table 6.1: Significant Power Station Developments in the NEM since 2000[8]

Power Station	*Year of Actual/Initial Operation*	*State*	*Capacity*	*Technology*	*Developer*
Pelican Point	2000	SA	485 MW	Gas (CCGT)	International Power
Ladbroke Grove	2000	SA	80 MW	Gas (OCGT)	Origin Energy
Oakey	2000	Qld	286 MW	Gas (OCGT)	Babcock & Brown/ERM
Callide C	2001	Qld	920 MW	Coal	CS Energy/ InterGen
Redbank	2001	NSW	150 MW	Coal	National Power
Bairnsdale	2001	Vic	94 MW	Gas (OCGT)	Duke Energy
Tarong North	2002	Qld	443 MW	Coal	Tarong Energy/ TEPCO
Swanbank E	2002	Qld	385 MW	Gas (CCGT)	CS Energy
Millmerran	2002	Qld	850 MW	Coal	InterGen
Hallett	2002	SA	180 MW	Gas (OCGT)	AGL

[7] Section 7 of the National Electricity Law

[8] Expert Report 3, p.49

Power Station	Year of Actual/Initial Operation	State	Capacity	Technology	Developer
Quarantine	2002	SA	96 MW	Gas (OCGT)	Origin Energy
Valley Power	2002	Vic	300 MW	Gas (OCGT)	Edison Mission Energy
Somerton	2002	Vic	150 MW	Gas (OCGT)	AGL
Angaston	2005	SA	40 MW	Oil	Infratil
Yabulu	2005	Qld	220 MW	Gas (CCGT)	Transfield
Braemar	2006	Qld	455 MW	Gas (OCGT)	Babcock & Brown Power
Laverton North	2006	Vic	320 MW	Gas (OCGT)	Snowy Hydro
Kogan Creek	2007	Qld	750 MW	Coal	CS Energy
Quarantine Expansion	2008	SA	120 MW	Gas (CCGT)	Origin Energy
Tallawarra	2008 (1)	NSW	400 MW	Gas (CCGT)	TRUenergy
Colongra	2009	NSW	667 MW	Gas (OCGT)	Delta Electricity
Uranquinty	2009	NSW	640 MW	Gas (OCGT)	Babcock & Brown Power
Braemar	2010	Qld	630 MW	Gas (CCGT)	Origin Energy

Parties likely to invest in generation in New South Wales generally expressed a high degree of confidence that the NEM can provide appropriate signals for required new investment, and is superior to a more centrally planned approach to delivering generation investment:

'it's our belief that a properly functioning, efficient and informed environment it is the market that will respond most efficiently to the energy needs and timing of supply'.[9]

'retailers are generally confident that the National Electricity Market (NEM) can deliver investment of the right type to the right locations in a timely fashion. In this regard, the Association does not consider there to be a need for the government to intervene in the market or directly underwrite new investment in any way … We note that to date wherever price signals have been strong enough in the NEM investment has been delivered; particularly in Victoria, SA and Qld'.[10]

'…IGA recognises that the electricity market, functioning free of externally imposed distortions, sends effective signals to potential investors about the required timing, type and size of new generating capacity'.[11]

[9] Infrastructure Partnerships Australia submission, p2

[10] Energy Retailers Association of Australia submission, p1

[11] Intergen Australia submission, p2

Uncertainty in policy setting may reduce reliability

In general there has been a high reliability of generation in the NEM and sufficient capacity from the energy market to meet consumer demand.

The Reliability Panel's[12] observations on system reliability which echo those of the parties likely to invest in generation, are that the fundamentals of the market design are sound and, with the current settings, the reliability standard is likely to be met in the near term, provided the fundamentals remain in place.

The Panel does observe however that there is increasing risk, in the medium to long term, that reliability may be compromised if reduced investor confidence as a result of uncertainty about other policy settings created potential delays with new generation investment[13].

The recommendations of the Inquiry in effect will address the policy settings of concern to investors as set out in Chapter 7.

6.4 Maintaining the State's AAA credit rating

New South Wales has maintained the highest credit rating from Moody's (Aaa) and Standard and Poor's (AAA) since ratings commenced for the State in 1987.

Maintaining a AAA credit rating is a priority for Government.[14] The State Plan recognises that 'the AAA credit rating is the single most important signal that the NSW Government finances are being well managed'.[15] Appendix 6.2 sets out in more detail why maintaining the State's AAA credit rating is important.

What will affect the State's credit rating?

Standard and Poor's have given a clear message that to maintain the AAA credit rating the State Budget must be kept in surplus – 'the biggest risk to New South Wales' rating is its operating performance'.[16] In 2006, their report indicated that, although the State's strong balance sheet provides a buffer for now, large and sustained Budget deficits are not consistent with a AAA credit rating.

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[16]Reliability Panel, The Comprehensive Reliability Review, Interim Report, March 2007, p.43

[14] NSW Government, *State Plan - A New Direction for NSW,* Priority P5: AAA credit rating maintained, 2006, p.6

[15] Ibid, p.101

[16] Standard and Poor's Press Release: *AAA credit rating on New South Wales Affirmed: Outlook Remains Stable Despite Forecast Operating Deficits, 2006*

PTE debt is increasing

The State's balance sheet has been significantly strengthened over the last decade, with Total State sector net debt halving as a percentage of gross state product (GSP).[17] However, this trend has recently changed, with debt levels now forecast to increase over the next four years, principally to fund a large PTE capital spending program.

Overall, the risk of a credit rating downgrade in the short term appears very low. However, the ratings agency reports over the past two years have cautioned about the PTE sector's increasingly negative impact on the State's overall credit rating:

'Adherence to these revised [fiscal] principles and targets should help limit deterioration of the State's balance sheet and maintain its AAA credit rating, provided spending from PTEs remains under control'.[18]

'Standard and Poor's believes that adherence to the [fiscal strategy] principles is likely to be consistent with the maintenance of the State's AAA credit rating. This is provided the public non-financial corporations continue to be managed prudently'.[19]

What are the costs of public sector funding?

The necessary investment in new baseload would be funded by the private sector if the conditions in Chapter 7 are satisfied. Alternatively, new generation investment could be funded by the public sector. The fiscal impacts of these scenarios are considered in this chapter. Should the private sector perceive that the Government was intending to fund the next baseload investment in New South Wales, it is unlikely that the private sector would be willing to fund subsequent tranches of baseload, or even peak, generation for the foreseeable future. The concerns identified in Chapter 7 would be exacerbated by publicly funded baseload investment. Private sector caution already reflects the extent and concentration of Government ownership of generation in New South Wales, and further investment would deepen that sense of caution.

This Chapter assesses the alternative potential development pathways where the conditions are not satisfied and the incumbent State-owned retailers and generators fund generation needs over the next decade or so. This pathway is indicative and is used by the Inquiry to demonstrate how the fiscal position could evolve. In practice more detailed assessment on a case by case basis would be required before any investment was approved.

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[17] NSW Budget Statement 2007-08, Budget Paper No. 2, 2007, p.xi

[18] Standard and Poor's, Issuer Credit Rating: New South Wales (State of), 2005 p.4

[19] Standard and Poor's, Issuer Credit Rating: New South Wales (State of), 2006, p.5

The State could need to invest up to $15 billion

Chapter 2 of this report indicates that New South Wales will require new baseload generation. The exact cost and timing of NSW's emerging generation needs will depend on market participant's evaluation of energy growth trends, energy efficiency achievements, the cost of carbon, growth in renewable generation and potential supplies from the interconnection with other States.

Appendix 6.1 describes a potential development pathway used by the Inquiry to analyse the cost to the State of having to fund future generation needs. This pathway brings together potential generation sites in the State, forecasts of required generation capacity needs and the cost of new generation. The Appendix estimates the cost of new generation in the range of $7 billion to $8 billion.

Based on the Morgan Stanley findings,[20] the Inquiry also factored in the cost of investment in the retail businesses that would be necessary for them to become successful businesses in the NEM where they remain Government owned. Essentially, Government participation in the competitive segments of the electricity industry – retail and generation requires them to adopt business strategies similar to their private sector competitors

Appendix 6.1 details how the retail businesses must change and evolve under Government ownership or their value will erode over-time. The findings of Morgan Stanley indicate that a capital investment, potentially in the order of $2 billion to $3 billion, would be required to move the State-owned retailers onto a more equal footing with their private sector competitors.

Therefore together with the cost of new generation, the Inquiry considers the required capital investment by the State is in the order of $9 billion to $11 billion.

In assessing the fiscal impacts of the Government funding the State's generation needs, the Inquiry also found it necessary to consider the potential for further investments in existing power plants. In particular, the Government may be exposed to having to retrofit coal-fired power stations with emerging carbon reduction technologies. For the purpose of modelling the fiscal impact on the State, the Inquiry considered this cost in the range of $3 billion to $4 billion.

Hence, for the purpose of modelling the fiscal impact from publicly funding the State's emerging generation needs the Inquiry used a total funding requirement of $12 billion to $15 billion over the next ten to fifteen years.

[20]*Expert Report 3, pp150-156*

The timing of the total investment pathway will depend on market circumstances. However, it is likely that new investment for peaking plant and further investment in retail activities of between $4 billion and $5 billion would be over the first half of the period till 2020. New investment for base load generation and the retrofit of existing plant of between $8 billion and $10 billion would be over the second half of the period till 2020.

The State's capital program is described in the State Infrastructure Plan and (for the next four years) set out in detail in the 2007-08 State Budget Paper No. 4. The capital program includes significant investment in electricity networks to enhance reliability. The program does not however include any major generation investment beyond Delta Electricity's approved Colongra project.

The State-owned energy corporations capacity to fund

For the purpose of explaining potential impacts on the State's credit rating the Inquiry has modelled the cost of fully funding the investment pathway through debt. That is, it does not incorporate re-prioritisation of existing or future expenditure or tax increases.

The impact on the State's fiscal position can be considered on an aggregated energy portfolio approach – rather than an energy business specific level - because:

- each energy SOC (generation and distribution/retail) has a different capacity to internally fund new investment, however the difference is not great
- the funding requirement for the investment pathway would influence the State's credit rating primarily through increases in Total State Sector debt. Total State Sector debt captures both aggregate PTE[21] debt and General Government Sector (GGS) debt. In terms of the State's credit rating, the financial impacts on individual SOCs from funding new generation are secondary considerations compared to the financial impacts on the SOC energy portfolio and State as a whole.

NSW energy SOCs have capital structures similar to comparable private sector energy businesses. On average, debt gearing levels[22] for both the generation and distribution/retail sectors are close to the upper end of an appropriate commercial capital structure range. For the generation SOCs debt funding of more than 50 per cent of new investment, would increase debt levels to commercially unsustainable levels, thereby negatively impacting on their stand-alone credit ratings and resultant cost of debt.

[21] For the purpose of the NSW State Budget, SOCs are a subset of the Public Trading Enterprise Sector.

[22] Measured by debt / (debt plus equity)

Consequently, the cost of the investment pathway would require 50 per cent debt funding from the energy SOCs and 50 per cent 'equity' funding from general government sector. In the absence of offsetting reductions in the GGS's own capital programme, which is dominated by roads and social infrastructure, the general government sector would need to increase its own borrowings to provide equity injections to the energy SOCs.

The additional investment should generate earnings sufficient to cover the increased SOC interest costs and provide a return (through tax and dividends) on the Government's equity investment. Historically, investments undertaken in electricity have not always been commercially successful. Actual returns have varied and will depend on market conditions. Investment in the competitive generation segment has risk, and returns in excess of the incremental borrowing costs are not guaranteed.

6.5 Impact on the State's Finances

Funding the development pathway through a combination of the SOC borrowings and Government equity injections will impact on both the General Government Operating Statement and Total State Sector Balance Sheet:

How would the General Government Operating Statement be affected?

The General Government operating statement may be improved as a result of any higher dividend and tax equivalent payments resulting from the general government sectors increased equity in the PTE sector. However, the operating statement will be lower by the increased interest costs on the additional GGS debt required to fund required equity injections.

Increased dividend and tax equivalent payments should at least offset increased finance costs as the Government should receive a return on its equity investment at least equal to the Government's cost of debt. While on average this may be case over the life of the investment, dividends will vary from year to year and hence a degree of increased volatility will be introduced to the General Government Budget Result.

Overall, any operating statement impacts increase gradually over the medium term and are of the order of an extra $10 million to $20 million a year. This is minor when compared to impacts on the State's Balance Sheet. Potential positive impacts on the Budget result should also be considered in conjunction with the high-risk nature of generation / retail investment and resultant impacts on the State's overall risk profile.

How would the balance sheet be affected?

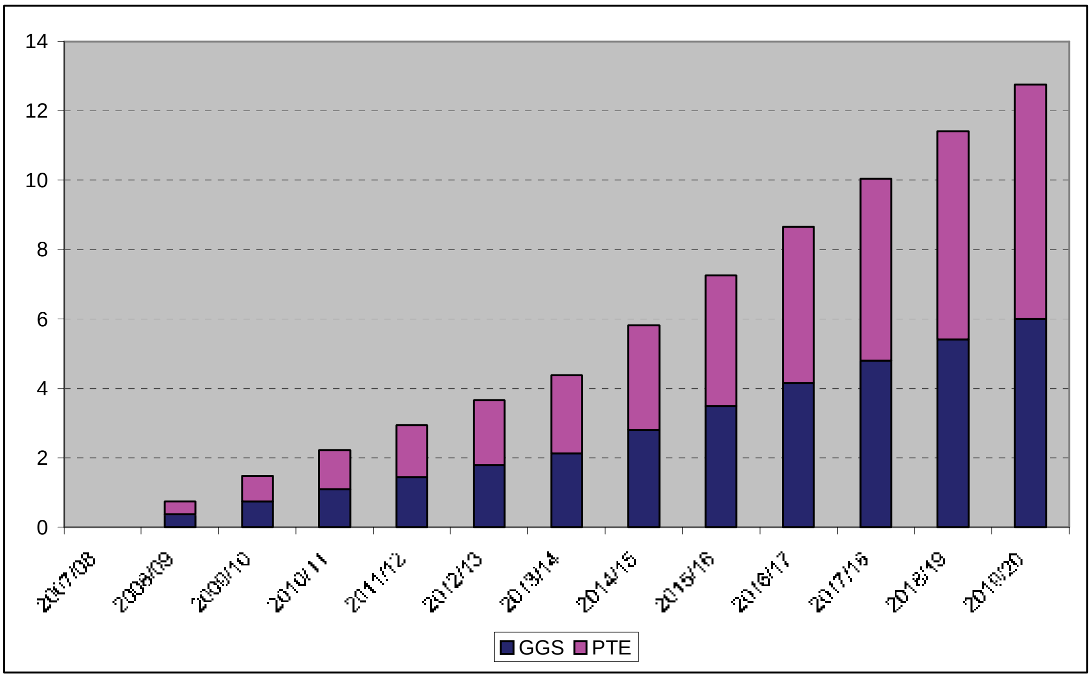
Medium-term financial projections carried out by NSW Treasury indicate that significant increases in infrastructure spending as set out in the State's Infrastructure Plan will put pressure on the State's balance sheet, even before the impacts of the electricity sectors investment pathway are factored in. Funding the investment pathway will further increase debt levels in both the GG and PTE sectors.

Overall, the investment pathway will be funded entirely by additions to Total State Sector net debt. Increased borrowing will be required by the GG sector to fund PTE equity injections. The PTE sector will require further borrowings to fund the remaining 50 per cent of the investment pathway.

Debt would increase by over $12 billion

The investment pathway will increase Total State debt by almost $12.8 billion by 2020, reflecting the total mid-point investment path of $13.5 billion, partially offset by projected cumulative operating surplus impacts of around $0.7 billion. The impacts on both GGS and PTE debt (and aggregate Total State debt), are shown in Figure 6.2:

Figure 6.2: Impact on Total State Debt ($ billion)



The State's total Net Worth will remain unchanged, as increased borrowings will be offset by a corresponding increase in assets.

How could the State's credit rating be affected?

The objective of the Government's medium-term fiscal strategy is to maintain service delivery, notwithstanding economic and fiscal shocks. This is achieved by maintaining low levels of net debt and net financial liabilities so that the State can absorb the effects of cyclical revenue fluctuations by allowing a temporary increase in borrowings rather than having to reduce services or raise taxes. The State's balance sheet has improved substantially over the last decade with both net debt and net financial liabilities declining substantially as a share of the economy in both the general government and total State sectors.

Net debt is already increasing

However, in recent years a combination of cyclical and structural events has led to lower State Budget surpluses. In combination with recent increases in the capital spending program, including in the non-commercial PTE sector, net debt in the general government sector is projected to increase over the forward years. At the same time, however, the PTE sector has a large capital spending program, which will lead to a substantial rise in its net debt and that of the total State sector over the next decade. Appendix 6.4 provides more detail on the State's capital investment program.

PTE sector net debt increased from around $8 billion in 1995 to $13.8 billion in 2006, but has remained relatively flat as a percentage of GSP at just over 4 per cent. However, PTE net debt is projected to increase rapidly over the next 5 years, reflecting increased capital investment, reaching $33 billion in 2011 (7.8 per cent of GSP).

To assist the Inquiry, NSW Treasury was asked to develop a medium-term fiscal model to analyse the impacts of funding the State's electricity generation needs. The starting point for this modelling is the Budget and forward estimates as contained in the 2007-08 State Budget. This provides information through to 2010-11. Beyond this period, projections of the operating statement and balance sheet for the general government, PTE, and total State sectors were developed out to 2019-20, including the impacts from the required electricity funding considered above.

The first part of the modelling projected the General Government operating balance beyond the forward estimates. While general government revenue growth can be volatile it has averaged around 5 per cent growth per year over the last decade. Expenses growth has been above that trend growth in recent years, but global savings measures and the government's wages policy are designed to slow expenses growth to trend revenue growth. With revenue growth equal to expenditure growth the currently projected operating surpluses of around $500 million per annum over the forward estimates are maintained beyond the forward estimates period.

Capital spending beyond the forward estimates period utilises the Government's announced ten year capital expenditure program, the State Infrastructure Strategy. Forecasts for the general government and PTE sectors are then aggregated to provide a total State forecast. Utilising these assumptions, projections beyond the forward estimates period suggest that the State's balance sheet and operating statement will be under pressure, even before the impacts of new generation investment are factored in.

The capital expenditure program contributes to average annual net lending deficits of over $1.7 billion in the general government sector in the years beyond the forward estimates. The scenario would see general government net debt increase from $7.4 billion (1.8 per cent of GSP) in 2011 to $22.7 billion (3.6 per cent of GSP) in 2020 and be on a continual rising trend. Total State net debt also rises in the years beyond the forward estimates, with total state debt rising from $39.3 billion (9.3 per cent of GSP) in 2011 to $77.4 billion (12.1 per cent of GSP) in 2020.

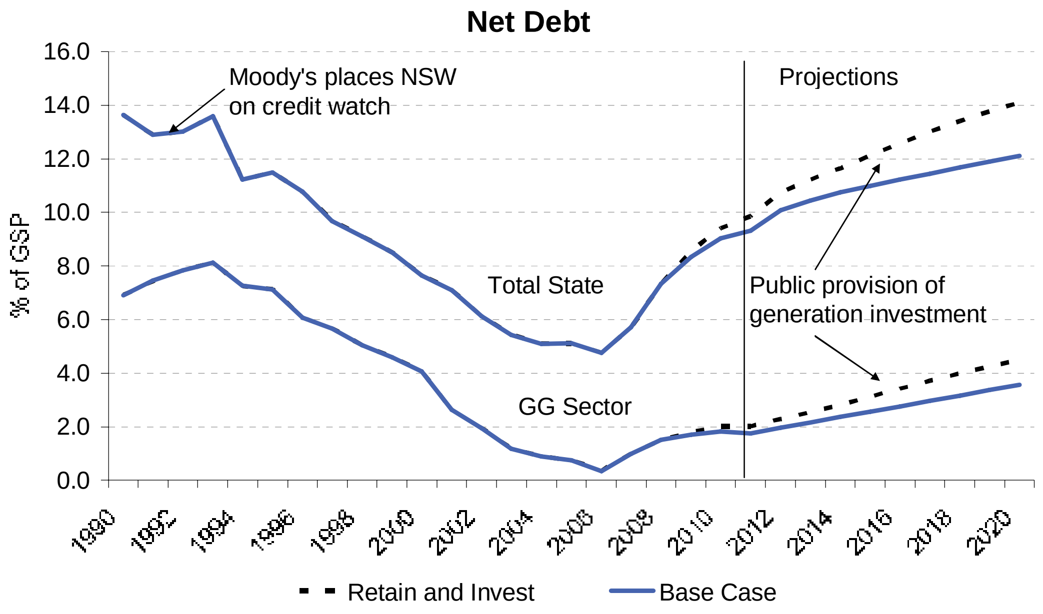
Government investment in generation could threaten the credit rating

Figure 6.3 shows the possible changes in net debt in the general government sector and total State sector over the coming decade with and without electricity retail and generation investment. It shows that, under these assumptions, total State net debt would approach levels (as a share of GSP) similar to when New South Wales was placed on CreditWatch for a possible rating downgrade in 1991. Indeed with public sector provision of generation investment, total State net debt would exceed the levels that were reached in 1991.

Apart from the level of debt, ratings agencies also focus on the speed of accumulation of debt. Under the public sector provision of generation scenario, total State debt continues to rise at roughly the same pace, with no signs of levelling out or the pace dampening. Such a trend would cause concern for the rating agencies.

Ratings agencies also pay attention to the composition of the total State revenue required to meet debt obligations, viewing revenue from public trading enterprises operating in competitive markets as inherently more risky than general government revenue.

Figure 6.3: NSW Net Debt: General Government and Total State Sectors



The balance of risks around the projections is weighted toward higher rather than lower levels of debt. First, the projected alignment between rates of growth of expenditure and revenues may not be maintained, which has been the experience over the past four years, where expenditure has tended to exceed revenue growth by around one percentage point a year. Secondly, the 2007-08 State Budget forward estimates assume that the growth in wage costs will be constrained to no more than 2½ per cent a year, whereas in recent years wage costs have grown by in excess of 4 per cent a year.

Further, as reported in the NSW 2006-07 State Budget Paper No. 6 *NSW Long-Term Fiscal Pressures Report*, the State's primary fiscal position is likely to deteriorate over the decade, in the absence of any policy change, as a result of increased expenditure pressures, both demographic and non-demographic in origin.

Ageing of the population will be a significant driver of expenditure pressures in health and social security and welfare. However, the report found that two thirds of overall expenditure pressures will come from non-demographic sources, reflecting the underlying growth in demand for government services, driven by rising living standards and community expectations, and the rising cost of new medical technologies and medicines.

If these higher expenditure pressures come to pass, total State net debt would increase at a faster pace beyond the forward estimates than projected, and would heighten the risk surrounding the maintenance of the State's AAA credit rating.

The State's current and committed capital program and the benefits accruing from this program are set out in further detail in Appendix 6.4.

Would government funding generation cause a credit rating downgrade?

Any additional debt funding will intensify the pressure on the State's credit rating. Under the electricity retail and generation investment scenario, total State sector net debt will rise to $90.2 billion or 14.1 per cent of GSP in 2020, compared to $77.4 billion or 12.1 per cent without publicly funding new generation expenditure.

Perhaps more importantly, the new generation investment increases the weighting of competitive assets within the State's total PTE portfolio. This increases the reliance on revenue from competitive markets in order to meet debt obligations which places further downward pressure on the State's credit rating.

Electricity generation is commercially risky

Credit rating agencies consider electricity generation as 'the riskiest segment of the electricity utility industry because of the complex operating risks and the increasingly competitive nature of the business'.[23] Given that Standard and Poor's has previously highlighted the importance of keeping PTE spending under control, further significant investment in the riskiest segment of the electricity sector would raise questions as to the State's commitment to managing PTE expenditure.

One of the key measures that ratings agencies use to assess financial performance is the ratio of net debt to operating revenues. This provides an assessment of the State's debt servicing capacity or ability to repay its debt. The lower the ratio, the higher the State is rated.

However, the composition of State revenues is important to ratings agencies in this context. The more revenues that are sourced from competitive public trading enterprises, where the revenue stream is riskier and hence less predictable than for regulated public trading enterprises or the general government sector, the lower the ratio of debt to operating revenues would be for a particular credit rating. Thus a State which relied on relatively more of its revenues from competitive public trading enterprises, such as electricity generation, would need to have less net debt than a comparably rated State which relied less on such revenues. To the extent this is the case, further public investment in the electricity generation sector in New South Wales will tend to crowd out other capital spending programs that could be wholly or partially debt funded by the Government.

[23] Standard and Poor's. *International Utility Ratings and Ratios*, October 2002, p.60.

It is difficult for the Inquiry to state categorically that continued Government ownership and investment in the State's electricity industry would provide a tipping point for the State's AAA credit rating. Although it is relatively straightforward to model the financial impacts, rating agencies include qualitative as well as quantitative factors in their assessments. Moody's has identified six key factors:

- the operating environment, i.e., national circumstances that affect the risk of an economic, financial market or political crisis
- the institutional framework that determines local government powers and responsibilities
- financial condition and performance
- the debt profile
- governance and management practices
- economic fundamentals.[24]

Public funding will have negative impact compared to private funding

Although forecasting government credit rating outcomes is necessarily inexact, it seems clear that public funding of electricity generation will be a negative influence on the State's credit rating.

The Inquiry was conscious that the ability of the Government to fund the State's emerging generation needs while maintaining the AAA credit rating was dependent on the estimated cost to do so. The Inquiry was also conscious with regard to the wide range of variability and outcomes in estimating such a cost.

Therefore, the Inquiry considers it important to highlight three key points relating to publicly funding new generation:

- First, it is not solely the size of required funding but it characteristics in terms of increasing the risk of the Total State Debt, and the signals it sends to credit ratings agencies with regard to the Governments forward capital program and its impacts on key financial metrics

[24] Moody's Investors Service, *Rating Methodology - Local and Regional Governments Outside the US*, October 2006

- Second, and perhaps more importantly, public investment in funding is not essential, so any associated funding requirement be it $1 billion or $10 billion will be at an opportunity cost to the public as these funds could have been allocated to the provision of other Government services. If the energy market is operating efficiently and the regulatory system is working properly then having a secure energy supply, competitive prices for consumers and protections for environment can be secured without government investment.. While ultimately a decision for Government, the Inquiry considers that public investment in electricity generation (which can be funded by the private sector) should not come at the expense of investments in health, education and transport which are not likely to be made by the private sector.
- Third, as discussed in Chapter 7, the alternative to publicly funding the State's emerging generation needs is to privately funding them. To ensure the private sector invests the Inquiry recommends that the Government divest its electricity generation and retail interests. Comparing the fiscal impact of these two scenarios further highlights, in the Inquiry's view, that it is not just the order of magnitude of the funds required to publicly fund new generation but also the fiscal benefits from meeting the conditions for private investment. From the State's fiscal position, when comparing public sector and private sector funding of new generation, private sector funding will:
  - mitigate the need for an approximate $12 billion- $15 billion increase in total State sector net debt associated with continued ownership of generation and retail
  - release funds – otherwise unavailable to Government – to improve the State's fiscal position. These funds will arise from the sale of the State-owned electricity activities and economic interest of the generators necessary to create an environment where the private sector is willing and able to invest in significant generation in New South Wales. The Inquiry is not in a position to speculate on potential proceeds realised from a sale, but others in the public domain have speculated that $10 billion net of the debt in generation businesses[25] may be possible. Without endorsing this number the Inquiry puts it forward to inform the public of the order of magnitude of the potential changes in the NSW fiscal position.

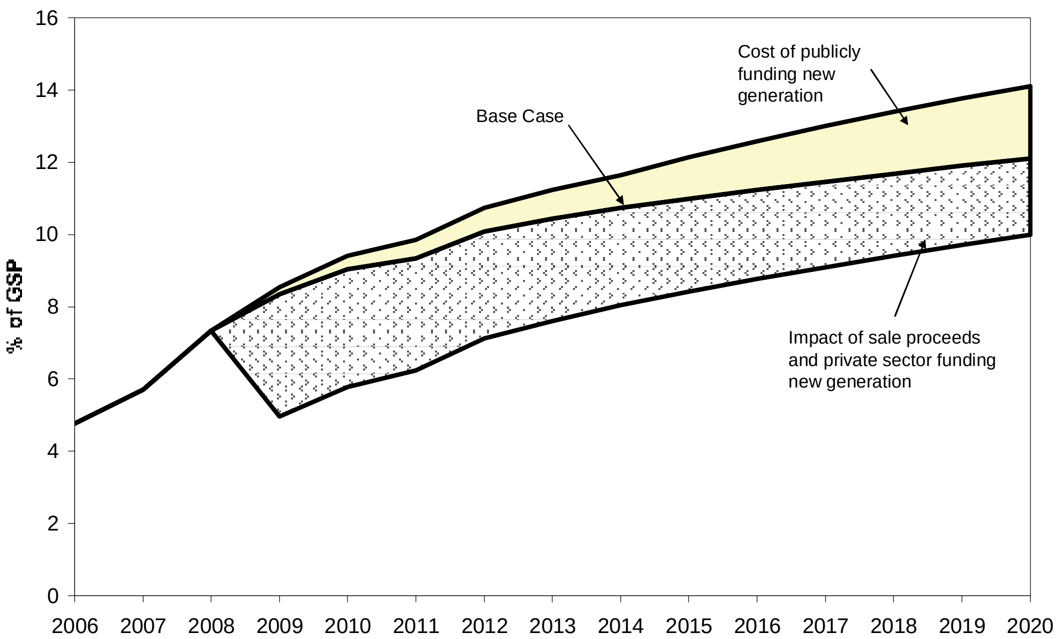
[25] Sales proceeds reflect a normalised estimate from all the valuations made through public speculation during the course of this Inquiry.

Assuming that the PTE sector and the general government sector jointly fund new base load generation capacity, there will be a significant impact on the State's fiscal position. Under this scenario total State sector net debt will rise to approximately 14.1 per cent of Gross State Product (GSP) in 2020 (based on the $13.5 billion total investment path mid-point).

If the generation and retail interests are sold the State Budget Result is impacted by reduced interest costs on general government Debt offset by foregone dividend and tax equivalent payments from generators and retailers. To give on indication of the degree of flexibility that divestment of the retail and generation sectors could provide to the State's balance sheet, if net proceeds of $10 billion was used to reduce GGS net debt then Total State Debt increases are limited to 10.0 per cent of GSP in 2020 under this scenario, compared to 14.1 per cent under the public funding scenario.

The impacts are set out in Figure 6.4.

Figure 6.4: Total State Net Debt as a Percentage of Gross State Product



Note: the 'base case' is the State's current and committed capital program as set out in Appendix 6.4.

7. Securing Private Sector Investment

Key Findings

- The private sector has demonstrated it will invest in new generation in the NEM under the right conditions.
- Surplus generation capacity has meant little investment has been needed in New South Wales to date. However, taking a risk-averse approach, New South Wales needs to be in a position where new baseload generation can be operational by 2013-14 if necessary.
- The private sector can manage the commercial risks in developing a power station but has less capacity to handle policy and regulatory risks. Submissions to the Inquiry highlighted carbon uncertainty and government ownership as impediments to investment.
- To secure on-going generation in New South Wales that is adequate, economic and timely, the NSW Government should transfer its retail and generation interests to the private sector.
- In transferring these interests, the Government will maximise the range of competing potential investors, quarantine risk to the State's fiscal position and AAA credit rating, and realise proceeds not otherwise available and likely to be eroded over time.
- This does not involve selling the 'poles and wires' of the State's electricity transmission and distribution networks.
- The Commonwealth Government should bring forward the timetable for establishing a national emissions trading scheme. At a minimum it should resolve and announce:
    - the national greenhouse gas reduction target and short term caps and associated penalties
    - the basis for allocating emissions permits.

7.1 Introduction

The Inquiry's consideration of private sector investment in generation was assisted by the detailed work undertaken by Morgan Stanley.

Morgan Stanley identified and assessed whether there are conditions in New South Wales that are deterring the private sector from investing in new generation capacity. They also developed and assessed the options available to the NSW Government, should it choose, to address the identified conditions.

Morgan Stanley's report is Expert Report 3 to this Report.

In this Chapter, the Inquiry considers the conditions and options identified by Morgan Stanley and reviews:

- the validity and significance of the conditions
- the necessity and effectiveness of the recommended options.

Given the history of generation investment in Australia, and the prominence of the public sector in funding this investment, Morgan Stanley assessed:

- whether the private sector has delivered generation investment, including peak, intermediate and baseload, in the NEM to date
- what conditions would most likely ensure private sector investment in generation in the New South Wales
- what conditions would most likely prevent private sector investment in new generation in the New South Wales
- are there any conditions specific to, or more prevalent in New South Wales, than in the rest of the NEM.

7.2 Private Sector Investment

As outlined in Chapter 6 previously, the Inquiry agrees that the NEM has worked well since its inception. The NEM has meet the market objective to 'promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system'.[1]

[1] Section 7 of the National Electricity Law

Would the private sector invest in generation?

Table 6.1 lists over 20 significant power station developments in the NEM, most of which have private sector involvement. There appears no lack of appetite by the private sector to invest in the NEM, under the right conditions. That this list includes very little investment in New South Wales is not surprising given the surplus generation capacity built in the 1980s and the development of interconnection with Queensland. Excluding Redbank, no new capacity has been commissioned in New South Wales since the early 1990s.

New South Wales is, however, beginning to need new capacity and this is being reflected in Table 6.1 with three gas-fired plants – Tallawarra, Colongra and Uranquinty – due to be commissioned in 2008-09.

Submissions to the Inquiry from those parties likely to invest in generation, are confident that the private sector will invest in generation capacity when a demonstrable market need reflected in wholesale electricity prices is predicted, and an investment case can be made for commercially viable operation and financing.

There is a growing market need for baseload

The existence of surplus baseload capacity and the development of interconnection between States have meant that there has been a limited market need for additional investment in baseload in New South Wales and, consequently, the economics in the wholesale market have not justified it. However, as discussed in Chapter 2 there is an emerging need for new baseload capacity in New South Wales. Further, while views on timing vary, TRUenergy's view is representative of the consensus:

'In summary, we believe baseload investment could be required from as early as 2012, however, there is significant uncertainty in the forecast, and credible cases can be made out to 2015-16'. [2]

Markets can overcome business risks

Morgan Stanley has outlined the factors that constitute a generation investment decision. Investment in power generation is technically complex, commercially risky and capital-intensive. Even prior to commissioning, the investment process exposes developers to business risk associated with:

- locating, acquiring and obtaining development approval for an appropriate site
- sourcing fuel and negotiating fuel contracts
- obtaining a sufficient level of debt finance at appropriate interest rates
- construction costs and timetables.

[2] See Morgan Stanley Expert Report 3, p.70.

Once a power station is operating, there are ongoing risks of:

- volatility in wholesale electricity prices, which can vary significantly in half hour intervals
- availability and operational efficiency of the plant
- changes in interest rates, which will affect the cost of servicing debt and the returns to equity investors
- another new power station being built, which has a lower operating cost and therefore is earlier in the merit order.

Policy risks will discourage investment

The Inquiry notes that markets have developed to handle some, if not most, of the commercial risks associated with power station development through a variety of mechanisms. However, markets have limited capacity to quantify and handle policy and regulatory risks.

Table 7.1 demonstrates that all types of generation (and their associated fuel sources) have different characteristics which mean market participants will face different market and policy risks with each technology.

Table 7.1: Qualitative Comparison of Generating Technology by Risk Characteristics

Technology	Unit Size	Lead Time	Capital Cost/kW	Operating Cost	Fuel Cost	CO_2 Emissions	Regulatory Risk
CCGT/OCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very large	Long	High	Medium	Low	Nil	High
Hydro	Very large	Long	Very high	Very low	Nil	Nil	High
Wind	Small	Short	High	Very low	Nil	Nil	Medium
Recip. Engine	Small	Very short	Low	Low	High	Medium	Medium
Fuel Cells	Small	Very short	Very high	Medium	High	Medium	Low
Photovoltaics	Very small	Very short	Very high	Very low	Nil	Nil	Low

Source: Morgan Stanley Expert Report, p. 107

The characteristics of each type of generation form part of the decision making process for potential investors. For example, a comparative advantage of coal-fired generation is its lower fuel costs however, due to its higher CO_2 emissions it is greater exposed to policy risk through the cost of carbon and emission trading schemes.

The Inquiry notes, that in the above table 'Nil' for CO_2 emissions is for comparative purposes and in reality CO_2 emissions are low, not nil. Similarly, while OCGT and CCGT are described together on the table, operating costs for CCGT are generally higher.

7.3 Conditions for Private Sector Investment

Submissions to the Inquiry consider that an appropriate environment to ensure privately funded and efficient generation investment is a market that is commercially determined with a clear and transparent Government policy and regulatory framework. In particular, investors look for a market such as the NEM that provides for a commercially determined wholesale price of electricity so that the market need for generation is signalled primarily by the level of current and forward prices.

For example, Alinta states:

'Investors need clear rules to undertake a long term commitment such as a baseload power station. Appropriate policies need to be set firmly in advance of a project starting date (given the long lead times involved) and need to remain in place for the long term to give investors confidence that rules will not be changed arbitrarily'. [3]

The submissions are clear that a fundamental condition prior to any generation investment is an emerging or perceived market generation shortfall reflected in wholesale electricity prices. With general confidence in the NEM framework as set out in Chapter 6; the two most significant issues identified by the submissions to the Inquiry are the perception that government ownership creates in market participants and the uncertainty arising from greenhouse gas policy.

Policy and regulatory risks must be reduced

As discussed in Chapter 6, New South Wales is now unusual within the NEM, with a high level of Government involvement in the State's electricity industry. The NSW Government is the owner of the vast majority of the State's electricity transmission, distribution, generation and retail businesses.

A number of submissions touched on the market uncertainty created by government ownership. For instance, uncertainty around the capability of the State's existing power stations and the investment intentions of the SOCs was noted as a cause of concern when considering investing in new generation. Of the policy and regulatory risks almost all submissions mentioned the importance of more certainty on greenhouse gas emissions policy. Greenhouse gas emissions policy is discussed in Chapter 5.

[3] Alinta submission, p.4

What conditions are needed?

Access to a stable revenue stream

Investors will not invest if they cannot form a reasonable expectation that they will earn a return from their investment. For generation, the expectation of return is based on their expectations of the prices available in the electricity spot and contract markets when the power station is completed and operating.

To provide greater certainty, and reduce risk around future market prices and revenue, power stations owners have adopted business models that provide a relatively stable stream of revenue and earnings. The three most prominent models are:

- fully contracting the power station's future output
- incorporating the power station as part of a vertically integrated portfolio
- incorporating the power station as part of a generation portfolio.

In Australia, the trend has been towards portfolio generation and vertical integration. Each of these business models and how they create an incentive to invest in generation are considered in some detail in the Morgan Stanley Report and summarised in the following section.

Vertical integration insulates earnings from volatility

Vertically integrated firms, such as AGL, Origin Energy and TRUenergy, are able to insulate their business's earnings from potentially volatile movements in wholesale electricity prices through having both retail customers and power stations. Such models, commonly referred to as 'gentailers', have evolved largely from the requirement for large electricity retailers to add generation capacity to offset the risk from variable input costs (wholesale electricity prices) being sold at a fixed cost to customers (regulated price caps or contestable contracts).

The addition of generation to a retail base:

- provides greater flexibility (i.e. control over dispatch of plant) compared to contractual arrangements to manage wholesale price risk
- tends to reduce the risk of the business, resulting in a lower cost of capital and higher credit rating
- provides opportunities to realise greater business synergies.

In considering the incentive to build, AGL noted in its submission that 'nearly all additional generation capacity in the NEM resulting from investment by the private sector, has had some form of downstream support in order to improve revenue certainty'.[4] Table 7.2 below illustrates this point.

Table 7.2: New Generation in the NEM

Project	Technology	Location	Downstream Support
Pelican Point	CCGT	SA	Medium-term contracts with ETSA and AGL
Valley Power	OCGT	Vic	Medium-term contracts with Pulse
Ladbroke Grove	Gas	SA	Origin retail entry in SA and incumbency in Vic
Quarantine	OCGT	SA	Origin retail entry in SA and incumbency in Vic
Playford	Coal	SA	Medium-term contracts with AGL
Somerton	OCGT	Vic	AGL retail incumbency
Hallett	OCGT	SA	AGL retail incumbency
Bogong	Hydro	Vic	AGL retail incumbency
Bairnsdale	OCGT	Vic	Network support agreement with TRU
Laverton	OCGT	Vic	Red Energy retail entry in Vic
Braemar	CCGT	Qld	Long-term contract with Energex

Source: AGL submission, p.15

The view that businesses will have strong incentives to build generation capacity to support their electricity retail obligations is supported by Origin Energy's recent announcement of the construction of the 630MW CCGT at Darling Downs, following its acquisition of a Queensland retail customer base through its purchase of Sun Retail.

Portfolio generation reduces risk through diversification

Compared to the vertical integration model, which has been adopted by businesses who 'own' a retail customer base, the portfolio generation model has been adopted by businesses exposed to the wholesale cost of electricity through owning generation, such as International Power, Babcock & Brown Power, InterGen and Transfield. Portfolio generators are likely to be developers of new power stations, as this provides a mechanism to 'de-risk' the overall business through diversification of:

- geographical location - plant spread across different regions of the NEM allows the business to manage price and inter-regional risk

[4] AGL submission, p15

- physical insurance - multiple plant and hedge contracts allows the business to manage risk as another of their plants can cover for physical interruptions (scheduled or non-scheduled) of a plant
- fuel source – plant with different fuel sources (i.e. gas, coal, wind) allows the businesses to manage the risk of being reliant on a sole fuel source, provides an ability to dispatch least-cost plant to service hedge contracts, and creates competitive tension when negotiating fuel supply contracts
- revenue source – power station portfolios can include power purchase agreements (PPAs) and other forms of long term contracts as well as some merchant exposure to wholesale spot and forward electricity prices. Contracted revenues underpin earnings and provide access to a cheaper cost of capital, while the business can retain some upside benefit through exposure to pool prices.

Portfolio generators that have invested in the NEM are outlined in Table 7.3.

Table 7.3: Generation Portfolio Development in the NEM

Year	Plant	Developer	Detail
2009	Uranquinty (NSW)	Babcock & Brown Power	640MW - Natural Gas
2002	Milmerran (QLD)	InterGen	852MW - Black coal
2002	Valley Power (VIC)	Edison Mission	300MW - Natural Gas
2000	Pelican Point (SA)	International Power	478MW - Natural Gas
1990s	Hazelwood Refurbishment	International Power	1600MW -Brown Coal

Source: Morgan Stanley, Expert Report 3, p.85

To operate in New South Wales, these two business models require access to the NSW retail and generation market by gentailers and portfolio generators.

Access to sites is essential

Access to good sites is key to building a power station. In New South Wales, Government businesses currently own some of the most suitable and progressed generation development sites in the State.

EnergyAustralia, Delta Electricity and Macquarie Generation own peak and baseload gas-fired development sites at Marulan, Bamarang and Tomago, respectively. Delta Electricity and Macquarie Generation also own coal-fired baseload development sites adjacent to their existing power stations at Mt. Piper and Bayswater, respectively.

Compared to other greenfield baseload generation sites, the sites owned by the energy State Owned Corporations (SOCs) are:

- favourable in terms of access to fuel, water supply and transmission infrastructure. The coal-fired sites also are able to share infrastructure already provided for the existing power stations and integrate operations. This has the benefit of reducing construction cost and the long run marginal cost of the plant
- considerably progressed in the project feasibility and development approval stages. Project feasibility and development approval for baseload plants can take up to 3 to 4 years and the private sector are unlikely to commit capital to a baseload power station at a greenfield site that is behind a potentially competing project.

The Inquiry notes that without access to these sites the private sector is not likely to invest in competing sites that are commercially less favourable.

Access to competitively priced fuel

Before investing in a power station, potential investors will seek to manage their exposure to the cost and availability of fuel by contracting for a fuel supply and assessing the affect of fuel price changes on the economics of their power station. Given the focus on baseload generation and the conclusions of Connell Wagner on available generation technology,[5] this section focuses on coal and gas as generation fuel sources.

New South Wales has abundant coal resources, and the NSW Department of Primary Industries estimates recoverable coal reserves of in excess of 10 billion tonnes. This is equivalent to almost 300 years worth of NSW domestic coal consumption.[6] New South Wales also a long history of producing electricity from coal and consequently has existing infrastructure to support coal-fired generation.

As discussed in Chapter 3, Wood Mackenzie's conclusion on the availability and cost of gas for NSW baseload generation was:

- there is a reasonable expectation that there are sufficient gas supply resources to support long term gas-fired generation capacity additions in New South Wales, with higher gas prices expected to support further exploration and development of gas resources in Eastern Australia
- additional pipeline capacity will be required to meet the growing gas demand in New South Wales. [7]

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[5] Expert Report 1

[6] Expert Report 3, p91

[7] Expert Report 2, Executive Summary

Submissions to the Inquiry, and Morgan Stanley's discussions with market participants, have reinforced the expectation that additional gas supplies will be developed to support new gas-fired generation investment, should this prove commercial.

Consequently, the Inquiry considers that there are adequate coal and gas supplies/reserves available to New South Wales to supply baseload generation in New South Wales in the medium term – under the right economic conditions.

These economic conditions reflect the fuel supply issues considered by potential investors in generation when assessing the economics of a power station:

- the ability for power station owners to be able to pass-through market-wide movements in fuel prices
- adequate fuel-on-fuel price competition
- clear commercial drivers for investment in gas transmission infrastructure
- timely and appropriate development approval processes for coal mines and gas transmission pipelines.

The following section discusses these conditions in more detail.

Ability to pass-through fuel costs

In the case of electricity generation, the ability to pass-through costs relies on wholesale, and ultimately, retail electricity prices. The role of regulated retail price tariffs in New South Wales is of most relevance in this context.

Fuel-on-fuel competition

Fuel-on-fuel price competition is an important mechanism for power station developers to reduce their fuel price risk.

The Inquiry considers that Governments should, therefore, not seek to prohibit, or unduly favour, certain fuel sources for power generation, but should manage any externality costs of fuel (e.g. carbon emissions) via market-based instruments, which would allow environmental outcomes to be achieved while not comprising fuel-on-fuel competition.

Competition within a particular fuel sources (e.g. gas vs gas, coal vs. coal) and between different fuel sources (e.g. gas vs. coal) are both important in minimising fuel price risk. In particular, given the potential increase in demand for gas as a fuel source and therefore reliance on upstream gas competition, coal on gas competition can provide an external 'check' on the level of wholesale gas prices because if wholesale gas prices rise too high, production and investment will be switched from gas to coal. Eastern Australia currently benefits from gas prices that are low on a global scale. The substantial endowment of coal on the eastern seaboard, and the ability of electricity and gas to be substitutes in many applications, appears to have placed downward pressure on domestic gas prices in the past.

Commercial environment for gas infrastructure investment

Given that New South Wales is geographically remote from known gas sources, development of significant gas-fired generation within New South Wales is likely to rely on additional gas transmission infrastructure. In light of the 'lumpiness' of transmission infrastructure development, the commercial case for gas transmission infrastructure development often relies on a pipeline developer aggregating and contracting with multiple customers to form a "critical mass" of demand to support the infrastructure investment.

Notwithstanding that there are clear commercial drivers for energy players to underwrite new gas transmission infrastructure, continued investment in gas transmission infrastructure is likely to require:

- an acceptable level of regulatory risk for the developers of new gas pipelines (the Inquiry notes that Council of Australian Governments (COAG) and the Ministerial Council on Energy (MCE) have focused on gas transmission regulation in recent years, and the Australian Energy Market Commission (AEMC) and Australian Energy Regulator (AER) continue to progress reforms in this area)
- timely and efficient progression of land access and development approval for new gas pipelines.

Timely development approval for fuel sources

Recognising the significance of coal mine developments or gas transmission pipelines, a timely and transparent development approval and environmental assessment process is required by investors. In assessing this issue the Inquiry notes that in August 2005, the Government's 'Major Project' legislation came in to force to provide a single integrated environmental planning and approval process for major infrastructure and development in New South Wales. These reforms were implemented through Part 3A of the *Environmental Planning and Assessment Act 1979*, and replace assessment processes formerly applying to State significant development and major Government infrastructure projects.

The Inquiry recognises that these reforms have improved the planning approval process. However, given the significance of the planning approval process in constructing new power stations, and their associated fuel sources and infrastructure, and issues raised in the submissions, the Inquiry view is that New South Wales should continue to reform and improve the planning approval process.

Such improvements should aim to reduce the timetable to go through the process – in turn reducing the risk to electricity reliability from planning delays associated with commissioning new power stations. The importance of this is reflected in the comments of the Reliability Panel, that new power is being delivered in line with reliability standards, but with something of a narrow margin for error in some States and long or unexpected delays in development could compromise reliability.

The risk to reliability can also be highlighted by oversees experience where development difficulties were seen to have contributed to the California crisis in 2001.[8]

Lessons from other markets: Cumbersome development approval processes

The difficulties experienced in California in 2001 were contributed to by multiple factors acting over a single timeframe. One factor that has been commonly identified as contributing to the crisis was a cumbersome and slow authorization process for new generation plant. Multiple agencies and bodies were involved in/notified of new proposals as part of the process. Environmental concerns also delayed construction of new plant. In the period leading up to the crisis, review processes averaged well in excess of the targeted 12 month period. This was the case notwithstanding reserve levels at the end of the 1990's were less than 10 per cent, low by international standards, and demand growth was high. Development processes appear to have been disconnected from the realities of the marketplace.

The energy crisis in 2001 forced a radical streamlining of review of the siting of new power plant. The California Energy Commission developed accelerated processes for plants assessed to have no adverse environmental impacts and processes for peaking plant were reduced to as little as 21 days.

Importantly, the Inquiry notes that New South Wales should continue to improve the planning approval process to promote fuel-on-fuel competition. In particular, if gas-fired plants attract fewer development approval issues than coal-fired plant, this reduced development risk and quicker timeframe from commitment to operation, may be a significant factor in developers favouring gas developments, all other factors being equal.

[8] Expert Report 3, p102

Likewise, planning processes for electricity and gas transmission and other ancillary infrastructure can equally show overall development timeframes.

Retail pricing

While power stations sell their output directly into the wholesale electricity market, the revenues available to recover the costs of power generation ultimately come from retail tariffs. Inappropriate retail tariff regulation, which sets tariffs below the full cost of generating, transmitting and distributing electricity, and providing retail services to customers, can result in insufficient revenue being available market-wide to fund investment in new power stations. Without a clear source of revenue, the market simply will not invest in generation, as demonstrated in Ontario, Canada.[9]

Lessons from other markets: Distortionary policy responses

The retail electricity market in Ontario opened to competition in 2002. Prices increased above expected levels after market opening. The government responded by freezing prices at low levels, and met the difference in cost between the wholesale and retail prices – the cost ran into hundreds of millions of Canadian dollars in the first 12 months alone, and the government (in reality, taxpayers) found itself in the position of subsidizing electricity prices. In reality this simply represented a value transfer from low consumption taxpayers to high consumption tax payers via government fiat.

The price freeze raised regulatory risks and deferred investment, and yet consumption behaviour was unaffected as consumers were sheltered from market-reflective price signals.

The government found itself paying for higher prices and at the same time, had to contract for new capacity as it had distorted investment signals via its price freezes. This actually had political consequences and inevitably a new government moved to raise price levels to reflect underlying economics.

This graphically demonstrates that where government seeks to intervene in price signals, it is government (i.e. tax payers) who are likely to face the consequences.

The Inquiry notes that in 2009 the AEMC will be reviewing the effectiveness of retail price competition in New South Wales. The Inquiry supports the removal of regulated price caps at that time, should the review find effective competition in the NSW retail market.

[9] Expert Report 3, p131

The Electricity Tariff Equalisation Fund (ETEF) was introduced by the NSW Government in 2001 as a transitional mechanism to manage the risk that the State-owned electricity retailers are exposed to in purchasing wholesale electricity in a volatile market to supply default customers at regulated prices.

The Inquiry notes the premise of ETEF, and the NSW Government's decision to wind-down ETEF.

Government ownership is an impediment

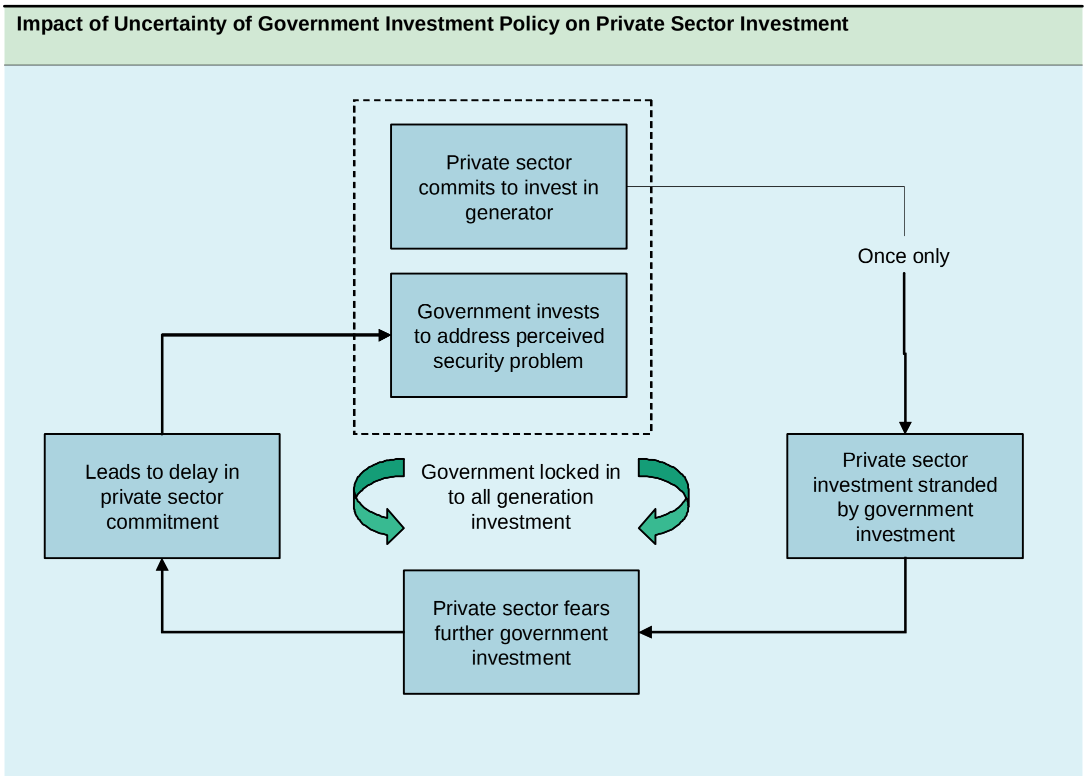
The Inquiry recognises the important role for government in energy market policy and regulation. The key NSW policy issue that affects private investment is the NSW Government's policy on future publicly-funded investment in power generation.

As set out earlier, the NSW Government is both policy-maker and owner of electricity businesses. This position creates a perception of a conflict for the Government. The Government has a preference for the private sector to fund new generation wants to ensure the 'lights stay on'. The conflict arises with the perception that an effective, although not the most prudent, way to keeps the lights on is for the Government as owner to build.

The submissions to the Inquiry highlighted this issue with Delta Electricity's recent announcement to build a gas-fired power station at Colongra. The NSW Government has indicated on a number of occasions its strong preference for the private sector to invest in new power generation and considers the Colongra decision is consistent with that preference.

However, rightly or wrongly, the private sector has concerns about the decision to build and some claim such actions deter private sector investment due to the potential stranding risk. The Inquiry notes that this perception has not stopped the private sector investors in both Tallawarra and Uranquinty. However, TRUenergy who are building Tallawarra, set out their views on the uncertainty government investment creates for investors in Figure 7.1.

Figure 7.1: TRUenergy Diagram on Uncertainty in Government Investment Policy



Source: TRUenergy submission, p. 29.

TRUenergy's diagram suggests the following chain of events resulting from market uncertainty about government investment policies:

- the market is uncertain of the government's investment intentions, particularly where this uncertainty has been exacerbated by prior government investment
- the market is then less confident of making future investment, and may not make timely investment commitments
- the government perceives that private sector investment commitments are not forthcoming, and decides to invest (again) itself in order to secure supply
- the private sector then becomes increasingly nervous about making its own investment in the future, leading to further investment delays, further perceptions of supply security by government, and further government investment.

The Inquiry considers that this cycle of uncertainty could result in the Government being locked in to making all future generation investment. To break this cycle, the Inquiry believes it would be necessary for the Government to make a credible commitment not to invest further in generation.

As considered in the options section of this Chapter, such a credible commitment could be made through Government divesting its interests in the competitive sectors of the electricity industry.

The Inquiry has not been presented with any evidence of non-commercial investment and other market behaviour by the SOCs. Assertions are not well founded and the Inquiry notes in particular that the bidding behaviour of a public sector business is subject to the same regulation as bidding by the private sector. Investment decisions must meet the same sort of rate of return criteria that are sought in the private sector.

However, the Inquiry concludes that such perceptions do exist in the market and do play a role in the private sector's decision to invest in generation in New South Wales.

Carbon uncertainty is an impediment

The Inquiry recognises that federally, a national emissions trading scheme should be implemented by 2012. As such, while investors in new power generation infrastructure are now factoring in an assumed emissions trading scheme they do not yet have critical details of how the scheme will operate in order to assess the impact on specific investment options. As discussed in more detail in Chapter 5, the annual emissions cap that government ultimately sets for the national emissions trading scheme will drive the carbon price. Until investors have certainty over the emissions cap they are unable to accurately forecast the likely price for emissions permits. The price for emissions permits could be critical in determining the most appropriate generation technology for investors to choose.

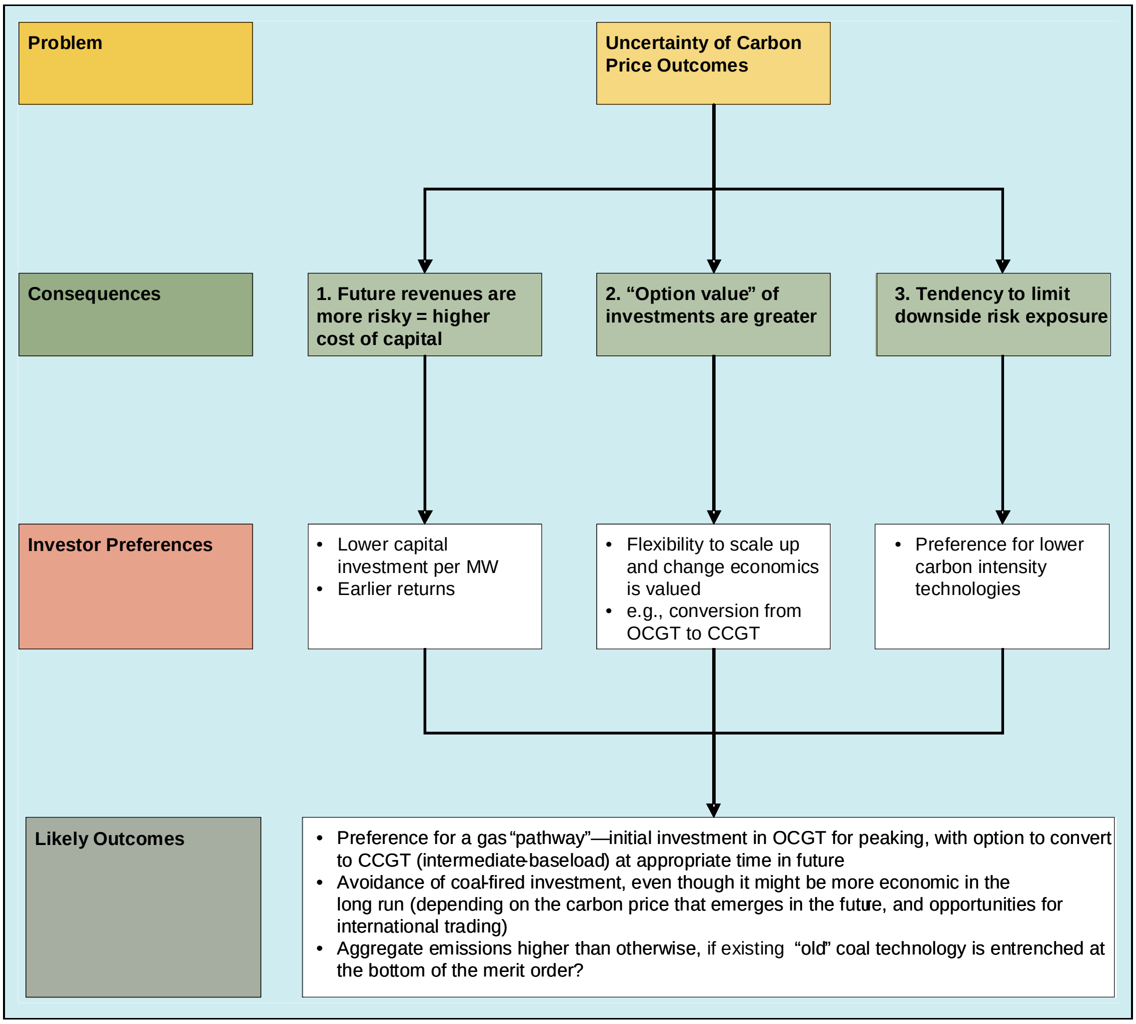
Submissions to the Inquiry are unanimous that investment in baseload generation will be delayed by uncertainty around a national emissions trading scheme.

The Inquiry believes greater regulatory certainty is necessary and the timetable for establishing the national emissions trading scheme must be brought forward. At a minimum the Commonwealth Government should resolve and announce the following key policy parameters:

- the economy-wide greenhouse reduction target and short term caps and associated penalties
- the criteria on which emissions permits will be allocated.

Without a timely resolution, the next tranche of significant investment in generation in New South Wales and the broader NEM will be made without an informed view of the future costs and regime for carbon. Under this scenario, it is unlikely the market will get the mix of generation technology right and ensure the most efficient market outcome, as shown in Figure 7.2.

Figure 7.2: Investment Decision-Making under Carbon Pricing Uncertainty



Source: Morgan Stanley, Expert Report 3, p. 126.

Figure 7.2 illustrates that in the face of uncertainty, investors will tend to limit their downside risk by avoiding investment in higher emissions power generation. This will result in a natural bias away from coal-fired power stations.

7.4 Options for Consideration by Government

Reflecting the approach taken by Morgan Stanley, the Inquiry has focused on options that:

- best address the identified conditions
- are available to the NSW Government to implement unilaterally and at its own discretion
- can be implemented in a timely manner to facilitate the required investment in generation capacity to meet the State's emerging supply needs.

The Inquiry concurs with Morgan Stanley's definition of 'actions available to NSW' with the NSW Government having:

- shareholder control over the SOCs [10] (within the constraints of the governance mechanisms under the *State Owned Corporations Act, 1989*)
- policy control over State-based policy
- no unilateral influence over NEM-wide issues, but formal influence through the MCE
- influence but no control over other issues such as potential emissions schemes introduced by the Commonwealth Government.

When considering 'options that best meet the identified conditions' the Inquiry was careful to relate those conditions and corresponding options back to the fourth term of reference - ensuring the State's emerging generation needs are meet in a manner consistent with maintaining the State's credit rating.

Reflecting the findings of Chapter 6, the Inquiry considered the key objective when assessing the options was 'does the option ensure the private sector will invest in the State's emerging generation needs'? Inherent in this objective is that such private sector investment occurs in an efficient manner that will ultimately promote competitively priced electricity for NSW residents.

[10] Country Energy, Delta Electricity, EnergyAustralia, Eraring Energy, Integral Energy and Macquarie Generation

Assessment of the options focused on their ability to address the issue underlying the identified conditions – turning any current policy and regulatory uncertainty into commercial risk that can be quantified and managed by the private sector. The greater the options do this, the greater their ability to:

- create interest by greater rather than lesser numbers of potential investors in generation; and
- give those potential investors stronger rather than weaker incentives for investment in all types of generation.

How can government maximise potential investors?

The Inquiry considers that the incentives to invest will be strongest when market conditions allow for a diversity of:

- generation investment business models
- generation technology types
- generation fuel sources.

Transfer interests in the State-owned retail operations to the private sector

Selling the State's retail operations would increase the private sector's commercial exposure to the retail load in New South Wales and facilitate businesses adopting a vertical integration approach to underwrite investment in generation capacity in the State. Businesses that are exposed to a critical mass of retail load would have strong incentives to invest in new generation as part of their overall risk management strategy.

Transfer the interests in the State-owned generators to the private sector

This would increase the private sector's commercial exposure to generation output in New South Wales and facilitate businesses adopting a generation portfolio approach to underwrite investment in generation in the State. Businesses that have existing power stations would have strong incentives to invest in new power stations as part of their overall risk management strategy.

The Inquiry notes that the generators should be sold to the private sector. In the event that the Government does not wish to sell generation, then appropriately structured long-term leasing of current generation assets should be considered as a viable alternative.

The Inquiry recommends transferring both retail and generation to the private sector as this would:

- maximise the likelihood of private investment in generation consistent with the State's emerging generation needs
- increase the number of companies potentially operating in the electricity sector in New South Wales i.e. both the retail-long and generation-long incumbents would have an incentive to invest in generation in New South Wales
- maximise the incentive for a new entrant in the State's electricity sector
- avoid either an erosion in value of the State-owned retail and generation businesses or a substantial State funded investment program in these businesses.

This will provide the highest level of confidence to the private sector that the Government will not unduly intervene in the market with government supported investment in generation capacity. Including the State-owned sites will also provide favourable development opportunities to potential power station investors.

Encourage the Commonwealth Government to determine an emissions trading scheme

In the absence of greater certainty, it is less likely that the market will make the most efficient decisions in new generation investment. An appropriate emissions trading regime should allow for investment in a range of generation types. The Commonwealth Government should bring forward the timetable for establishing a national emissions trading scheme.

Transfer State-owned generation development sites to the private sector

The Government currently owns a number of potential generation development sites that are suitable for coal and gas-fired power stations. The Government should encourage the SOCs to submit all sites for development application. Making these sites, with development approvals, available to the private sector will ensure coal-fired and gas-fired generation technologies are available to potential power stations developers.

Improve the State's planning approval for new power stations

Improvements to the State's planning approval process should be conscious of the need to assess coal-fired, gas-fired and renewable power stations on an equal footing.

How can government privatise its interests?

Recognising the significance of the keys findings of this Inquiry and the recommendations that Government should divest itself or its retail and generation interests – the mechanism that in the past has ensured the adequate generation supply to the State – the Inquiry has considered two key issues:

- what does transferring the State's retail and generation interests involve
- will divesting both the State's retail and generation interests maximise the value of these assets to the NSW Government.

Retail

The retail operations are a small component of EnergyAustralia, Country Energy and Integral Energy. Around 10 per cent of these businesses' operations and staff are retail related. The balance of the business is involved in owning, operating, maintaining and developing electricity infrastructure (i.e. 'poles and wires').

Importantly, the retail operations do <u>not</u> own any energy infrastructure. Their main assets are computers systems (eg. billing and payment systems). The existing State-owned electricity businesses will continue to own the 'poles and wires', and will be entirely focused on maintaining the reliability of the State's electricity distribution network.

The Inquiry considers the electricity retail function comparable to a financial intermediary, much like a bank or an insurance company:

- they buy electricity on the wholesale electricity market, and enter into a range of financial hedge contracts to manage the price risk they are exposed to
- they 'on-sell' this electricity to customers at prices determined by the Independent Pricing and Regulatory Tribunal (IPART), or agreed under negotiated contracts between the retailer and it customers
- in doing this, retailers effectively manage their customers' financial exposure to volatile wholesale electricity prices - so customers can have certainty of their electricity prices
- retailers also collect revenue for network charges, on behalf of the owners of the electricity transmission and distribution networks, so that both customers and energy sector participants can have the convenience of a single bill for both energy and network services.

To undertake these functions, retailers generally have the following staff and assets which comprise around 10 per cent of the three State-owned retailers:

- staff who trade electricity, by monitoring the retailer's wholesale purchase requirements and entering into financial hedges with other parties to manage the associated risk
- sales and marketing staff, who market the retailer's 'products' to potential customers, in both New South Wales and inter-state
- customer service functions - call centres to take product and billing inquiries (these call centres often also handle inquiries relating to the network business eg. supply interruptions)
- billing functions - computer systems which retrieve and store customer consumption data and generate bills (these billing systems sometimes also handle billing procedures associated with the network business
- revenue collection functions - payment systems which collect payments from customers (cash, cheque and electronic) and record them against the appropriate customer accounts.

Generation

The most effective method to divest the State's generation interests is to sell the State power stations. This will give the private purchaser full exposure to the financial risks and benefits of generation, and provide an effective platform from which to build new generation capacity. The private sector is much more likely to build if it can operate new generation as part of a portfolio with existing generation assets.

However, the Inquiry is of the view that appropriately structured long-term leases could be used to transfer the State's economic interest in generation to the private sector. To ensure that the private sector gets full financial exposure to generation, and therefore has the strongest incentives to build new generation, the leases will give the lessee:

- a term that exceeds the estimated remaining life of the existing generation assets, and any upgrades / improvements / additions the private sector may make on the generation site
- full rights to bid and contract the output of the power stations, subject to whatever contractual obligations are currently in place (e.g. long-term power supply agreements) which will be transferred to the lessee
- responsibility for the day-to-day operations of the power station

- responsibility for sourcing future fuel supplies for the power station, along with the benefits and obligations of existing fuel supply contracts
- responsibility for maintaining the power station, and the right to invest extra capital to upgrade units or build new units on the power station site
- exposure to the risk of future market-related policies and instruments (e.g. carbon trading).

In exchange for the financial benefits of the generation assets, the lessees will be required to make ongoing lease payments (or an equivalent up front payment) to the Government i.e. the Government will effectively swap its current exposure to the variable financial performance of the generation businesses to a pre-agreed payment stream from the lessees.

Divesting both retail and generation is necessary

At a market level, the interaction of the demand for contracts (from retailers) and the supply of contracts (from generators) means there should always be more generation capacity in the system than expected demand.

Although, retailers tend to take a conservative approach to contracting – they would rather be over-hedged (i.e. contracted for slightly more than their expected retail load) than under-hedged, because the financial consequences of being 'caught short' at times of peak demand are large.

Parties with significant exposure to retail load will ensure there is always enough generation capacity – they will 'keep the lights on'. Retailers are financially exposed to high and volatile power prices during times of peak demand, when prices can reach $10,000/MWh (i.e. over 200 times average power prices). This gives them every reason to build generation plant to cover their risk. The financial consequences of not being hedged at peak times are so significant, that they can't afford to "let the lights go out". Retailers' incentives to ensure enough generation capacity at all times are fully aligned with the Government.

Generators, on the other hand, will tend not to contract all their capacity – they will usually keep at least one unit uncontracted, because if there is an unexpected outage they will be forced to buy power on the spot market (at potentially very high prices) in order to fulfil their contractual obligations to retailers.

Portfolio generators will continuously look for opportunities to improve the efficiency of existing generation capacity, and to invest in new efficient plant as demand grows – this investment will put downward pressure on power prices.

While retailers are focused more on risk management and their total margins, generators, on the other hand, will continuously look to reduce their costs and expand their generation market share – they will improve the availability of their existing plant, and invest in new units at the appropriate time.

If a portfolio generator doesn't invest, their competitors or new entrants will, which means their market share will be reduced – the threat of competing investment drives their commercial incentives to invest and keep investing over time.

As demand grows, the peaking plant developed by retailers will tend to run at higher and higher capacity factors, resulting in average power prices trending upwards. This will create commercial opportunities for portfolio generators to introduce more baseload capacity at the bottom end of the cost curve which will have the effect of putting downward pressure on power prices.

Generators are incentivised to diversify their risk over time by developing their portfolio. The more units they have the less they are exposed to the risk an individual unit fails, or a transmission outage, or they suffer from drought effects. A single unit or plant is more risky than a portfolio.

However, not all generators want to be or are retailers. Only by divesting the retail and generation will 'generator only' businesses have access to generation portfolio benefits in New South Wales.

Further generators, have a wide range of technical skills and have more coal-fired skills than at least some of the retailers. Selling generators will allow these 'generation only' businesses to utilise their skills and experience in order to maximise fuel-on-fuel competition, and ensure the widest range of coal and gas generation development opportunities are available in New South Wales.

Will divesting maximise the value of NSW assets?

The Inquiry has considered the following scenarios for private sector funding:

- a sale of the State's generation interests
- a sale of the State's retail interests
- a sale of both the State's retail and generation interests.

Divesting generation interests will realise market value

For the purpose of this discussion the Inquiry considers a lease of generation assets, almost equivalent to a sale of physical generation assets, in terms of ensuring private sector investment in new generation and realising value.

Such a scenario will provide an opportunity for the State to realise the current market value of the generation SOCs. Under this scenario, the private sector will take a long generation position that will make further private sector investment in generation more attractive through realising generation portfolio benefits. While this mitigates the need for the Government to fund new generation, it will expose the retail SOCs to adverse value impacts overtime as they continue to operate in an increasingly competitive market.

Under this scenario, the most likely acquirers include the current large vertically integrated energy businesses. The SOC retailing businesses do not own generation assets and hence will not be competitive with the larger vertically integrated private sector players. This position will be exacerbated if the large integrated businesses acquire and build the next tranche of generation in New South Wales as it will increase the scale and scope of these businesses. Consequently, they will become increasingly competitive on a cost-to-serve basis (in particular in New South Wales with the construction of physical generation in the State) compared to the SOC retailers.

As a result, the customer base of the retail SOCs will be progressively eroded over time as larger competitors churn more profitable customers, leaving the State with declining retail revenues and fixed costs. Consequently, the value of the SOC retailers will decline over time (without significant equity injections and permission to aggressively grow the businesses) and the State will be potentially required to write down the value of these assets on the State's balance sheet. This will have an adverse impact on the State's fiscal position and credit rating.

However, the Inquiry notes that even where the economic interests in the State-owned generators are not sold and/or equity is injected into the retail businesses, the value of the retail SOCs under continued Government ownership will likely decline. In particular, Country Energy and Integral Energy are currently sub-scale on a customer number basis and along with EnergyAustralia, operate under a superseded business model with higher operating costs per customer than their larger competitors.

Consequently, the NSW retail businesses have average EBITDA[11] retail margins around 2 per cent compared to AGL and Origin Energy forecasting margins of around 7 to 8 per cent.

Selling retail businesses will benefit NSW

Selling the retail businesses will provide an opportunity for the State to realise the current market value of the energy retail SOCs. This 'crystallisation' of current value will benefit the State's:

- immediate to medium fiscal position as it will allow equity locked up in the energy retail SOCs to be reallocated towards strengthening the State's fiscal position, with minimal off-setting reductions in financial distribution receipts;
- medium to longer term fiscal position by mitigating the potential erosion of the value of the energy retail SOCs on the State's balance sheet. Continued Government ownership of the SOC retailers – even where they receive equity to grow and/or the State funds new generation – cannot insure against a decline in value of these businesses over time as they operate in an increasingly national and competitive market.

Conversely, transferring the energy retail SOCs to the private sector will provide an opportunity to realise funds that can be used to reduce State debt – in turn strengthening the State's fiscal position and its capacity to deliver services. Given projected low (and deteriorating) retail margins, the resultant reductions in General Government interest costs are expected to significantly outweigh foregone retail tax equivalent and dividend payments.

Similar to the generation case, transferring only one component of the competitive electricity supply chain, in this case retail, may leave other sectors, in this case generation, exposed to an increasingly competitive and likely integrated national market.

The potential impact on the SOC generators is likely to be less immediate and sizeable than compared to the retailers. Investment in new generation will likely subdue wholesale market prices for a period after the investment (recognising the lumpiness of investment in new generation) therefore reducing the prices SOC generators are able to earn on their output. However, this is a natural function of the gross pool energy market and would occur regardless of whether the public or private sector invested in new generation.

Secondly, regardless of new private sector investment in generation, the SOC generators (and any generator in the market) should always be subject to equivalent commercial pressures. Essentially, the price of energy should always be influenced by the market entrant cost for a new generator.

[11] Earnings before Interest, Tax, Depreciation and Amortisation

However, despite this, private sector investment in generation in New South Wales will likely have an adverse impact on the value of the SOC generators, as the price for their hedge contracts may decline as they cannot capture the 'vertical integration' premium that is available to their major counterparties to these contracts. These counterparties will always have the option of constructing their own generation plant in New South Wales and will only contract with SOC generators up to their internal build price.

This potential loss in value of the generation sector, due to their inability to capture a vertical integration premium for their hedges, can of course be recovered by subsequent sale of the generators.

Despite this, selling the retail activities (and generation development sites) will only negatively affect on the value of the State-owned generators by curtailing their growth options.

Privatising both the retail and generation businesses will:

- avoid potential adverse impacts on either the generation or retail SOCs under either of the scenarios considered above; and
- maximise the potential sale value of the generation and retail energy SOCs to New South Wales, primarily through increasing the bidder field and consequently competitive tension for the NSW assets.

A1.1 Premier’s Press Release: Inquiry Announcement

Securing NSW energy needs – finding the balance

Wednesday 9 May 2007
NSW Premier Morris Iemma today announced the appointment of Professor Anthony Owen to advise the NSW Government on the potential need for a new baseload power station.

“On March 24 the people of NSW elected my Government on a platform of delivering the services that hard working families rely on,” Mr Iemma said.

“There are few services more basic than a reliable source of energy for our homes, businesses and industries, and there is no more important requirement than ensuring that our energy supply is as clean and green as we can possibly make it.

“A reliable energy supply is an essential part of a growing economy and the decisions we will take on this issue will make sure we can keep the lights on and keep our economy ticking over.

“I am determined to find the balance between powering our economy while maintaining NSW position at the forefront of climate change innovation.

“NSW already has Australia’s only emissions trading scheme, we now have a new opportunity to provide climate change leadership.

“If it decided that we need to move forward on a new baseload generator we will be at the same time searching for the cleanest, lowest emitting generating technology we can find.

“Today NSW has an opportunity to secure our economy while using the best available low emission technology to do so,” Mr Iemma said.

Recently, Professor Owen edited a book entitled “The Economics of Climate Change”, his own chapter focussed on the transition to renewable energies.
He has written other articles for international journals on energy use and the environment, and the economics of renewable energy.

The Premier said addressing NSW energy needs posed complex policy questions that require careful consideration.

"The National Electricity Market Management Company (NEMMCO), which runs the electricity market, has identified a potential need for new baseload electricity generating capacity in NSW from 2012-13.

"Six years might sound like a long time, but building power stations is an extremely complex process with very long lead times and there are firmly held views in the community about how we should proceed.

"That means we need to start taking the necessary decisions in the coming months in order to secure the reliable supply our state needs in time," Mr Iemma said.

Mr Iemma said that he had appointed Anthony Owen, a professor of Energy Economics at the Curtin Business School at the Curtin University of Technology in Perth to prepare a report for the Government on three issues.

They are:

- Review the need and timing for new baseload generation that maintains both security of supply and competitively priced electricity;
- Examine the baseload options available to efficiently meet any emerging generation needs;
- Review the timing and feasibility of technologies and or measures available both nationally and internationally that reduce greenhouse gas emissions;
- Determine the conditions needed to ensure investment in emerging generation, consistent with maintaining NSW triple A credit rating.

In establishing this inquiry the NSW Government is seeking advice on the actions required to ensure timely investment in generation capacity that addresses greenhouse gas emissions while retaining NSW fiscal position.

"On many of the key policy questions I am going into this process with an open mind," Mr Iemma said.

“On one however there will be no shift in our position – there will be no consideration of nuclear energy whatsoever.

“However make no mistake, if difficult decisions are necessary, then I will take them,” Mr Iemma said.

Professor Owen will advertise for submissions from the public and stakeholder groups and will report back to Government by the end of August.

A1.2 Snapshot of the NSW Electricity Sector

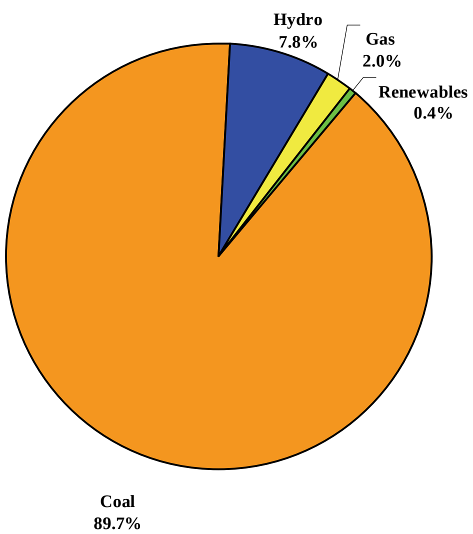
As New South Wales is the most populous State, the NSW electricity industry is the largest in Australia. Electricity is supplied to customers through four distinct sectors of the industry - generation, transmission, distribution and retail.

Generation

The generation sector produces electricity at power plants and offers it for sale, either through the wholesale market or under contract with particular retailers or end-users. The vast majority of electricity is sold via the wholesale market and dispatched by NEMMCO. The current generation capacity in the NSW region of the NEM is about 12,600MW. In addition, Snowy Hydro Ltd has a capacity of 3,700MW. These capacities are the amount of power expressed in megawatts that can be produced at a point in time.

Coal-fired generation dominates the market, as New South Wales has good local access to black coal reserves. Figure 1.2.1 shows total energy output in New South Wales by fuel source (coal, gas, hydro and other renewable sources like biomass, wind and solar). This is the total output usually expressed in megawatt hours and simply is the megawatts of the power plants multiplied by their annual capacity factors. Power can also be expressed as a gigawatt hour (GWh) which is 1,000 times larger than a MWh

Figure 1.2.1: Electricity Generated by Fuel Source, NSW in 2005-06 (including Snowy Hydro Ltd)



Source: Department of Water and Energy analysis of generation based on NEMMCO data.

Coal

There are eight coal-fired power stations in New South Wales, seven major State-Owned and one small privately owned:

State-Owned

- Macquarie Generation owns and operates two large coal-fired power stations in the Upper Hunter Valley – Bayswater (2,720 MW) and Liddell (2,060 MW)
- Delta Electricity owns and operates four large coal-fired power stations – Mt Piper (1,400 MW) and Wallerawang (1,000 MW) near Lithgow; and Vales Point (1,320 MW) and Munmorah (600 MW) on the Central Coast
- Eraring Energy owns and operates the Eraring coal-fired power station (2,640 MW) on the Central Coast.

Privately-Owned

- Babcock & Brown Power owns and operates a coal-fired plant in the Hunter Valley – Redbank (150 MW).

Gas

There is one small gas-fired power plant in New South Wales:

Privately-owned

- Marubeni Australia Power Services owns a co-generation gas-fired plant (160MW) at Smithfield.

In addition, there are a number of gas-fired power stations being planned or currently under construction in New South Wales. These include the 440MW combined cycle plant being built by TRUenergy at Tallawarra, near Wollongong, the Colongra 660MW open cycle plant being built by Delta Electricity at Lake Munmorah on the Central Coast and the NewGen Uranquinty 640MW open cycle plant being built by Babcock & Brown Power and ERM Power.

Hydro

Snowy Hydro Limited is jointly owned by the New South Wales, Victorian and Commonwealth Governments. Snowy Hydro comprises 16 large dams and seven power stations in the Kosciusko National Park area. Its total generation capacity is about 3,700MW, and it predominantly meets the bulk of the State's peak and intermediate generation requirements.

Eraring Energy owns and operates several hydro generators: Shoalhaven (240MW), Warragamba (50MW – currently disconnected), Hume (50MW), Burrinjuck (25MW), Keepit (7.2 MW) and Brown Mountain (4.95 MW).

Other renewable energy sources

Currently, renewable energy other than hydro electricity makes up about 0.4 per cent of the energy consumed in New South Wales.

The most significant solar thermal project underway in New South Wales is a solar thermal electricity plant being developed by Macquarie Generation at the Liddell power station in the Upper Hunter Valley. This plant is expected to generate the equivalent of 4.4GWh annually through displacement of coal for pre-heating boiler feed water. The Liddell power station can generate up to 13,000GWh per annum.

Currently New South Wales has one wave power generator, located in Port Kembla, which has a peak capacity of approximately 0.5MW.

Around 17MW of wind power has been installed in New South Wales. Eraring Energy owns and operates wind farms at Blayney (9.9MW) and Crookwell (4.8MW). A further ten wind energy projects, totalling around 540MW of additional wind power, have been given final development approval but are yet to commence construction. In addition, projects totalling a further 600MW are under consideration.

Biomass energy is energy that comes from organic matter. Delta Electricity and the NSW Sugar Milling Co-operative are jointly developing two 30MW co-generation plants at Condong and Broadwater on the North Coast.

The electricity network

The electricity network is made up of the transmission and distribution sectors.

Transmission

The high voltage transmission network delivers electricity from power stations to local distribution networks in major centres of demand.

In New South Wales, most of the transmission network is owned and operated by TransGrid, a NSW State-owned Corporation. TransGrid's assets comprise 12,440 km of high-voltage transmission lines and 82 substations and switching stations. EnergyAustralia and Directlink are also registered Transmission Network Services Providers in New South Wales.

Transmission prices and revenues are regulated by the Australian Energy Regulator under the National Electricity Law and Rules.

Distribution

The distribution network is the lower voltage network of local 'poles and wires' that takes electricity from high-voltage sub-stations and delivers it to end consumers.

In New South Wales the distribution network is divided between three State-owned Corporations:

- EnergyAustralia owns and operates the distribution network that delivers electricity to Newcastle, the Hunter Valley, Central Coast, and eastern Sydney areas. Its network comprises 49,000 km of power lines, 28,000 substations, 500,900 power poles and a service area of 22,275 square km.
- Integral Energy owns and operates the distribution network that delivers electricity to Wollongong and the Illawarra region, the Blue Mountains, Lithgow, the Southern Highlands, and western Sydney areas. Its network comprises 33,370 km of power lines, 27,800 substations, 315,000 power poles and a service area of 24,500 square km.
- Country Energy owns and operates the rural and regional distribution network that covers 737,000 square km or more than 90 per cent of New South Wales. Its network comprises 195,000 km of power lines, 113,000 substations and 1,400,000 power poles.

At present, the revenues and prices charged by distribution businesses are regulated by the NSW Independent Pricing and Regulatory Tribunal (IPART). However, as part of the energy market reform process being overseen by the Ministerial Council on Energy, responsibility for regulation of the distribution sector is expected to be transferred to the Australian Energy Regulator on 31 December 2007.

Network reliability

Network reliability in New South Wales is very high by comparison with other States and Territories in Australia and internationally. For example, in 2005-06, the average duration of supply interruptions per customer in New South Wales was only 143.10 minutes (out of 525,600 minutes a year), which is more than 99.97 per cent reliability.

Under the State Plan, the Government has committed to the target of achieving 99.98 per cent electricity reliability for New South Wales by 2016, which would further reduce the time a customer is without electricity by an average of 38 minutes a year. This reliability target relates to temporary unavailability of electricity following an outage of the electricity distribution system, and is known as the normalised reliability performance measure. It does not include 'excluded interruptions' as defined within the reliability licence conditions published by IPART. Excluded interruptions are those caused by major external events such as bushfires, severe storms or floods.

The Government has established strategies to identify geographical areas experiencing lower-than-average reliability, and to target resources at those areas to ensure improvements. More than $10 billion will be spent by TransGrid and the three distribution businesses over the next four years in substantially expanding and upgrading the network in New South Wales.

Retail

The retail sector comprises businesses that purchase wholesale electricity from generators and sell it to end consumers. Businesses supplying energy to retail customers in New South Wales must hold an electricity supplier's licence issued by IPART. At present, there are 24 licensed electricity retailers, including the State-owned Corporations EnergyAustralia, Integral Energy and Country Energy.

New South Wales was the first State to introduce full retail competition for both electricity and gas in 2002. Consumers can therefore choose to enter into supply contracts with their preferred retailer under competitive or negotiated pricing arrangements. Alternatively, small customers may continue to receive their electricity supply from the 'standard' retailer in their local area, under regulated prices set by IPART.

In all States and Territories, consideration is being given to the regulation of retail prices over the longer term. The AEMC is progressively undertaking a review of the effectiveness of competition in each State and Territory. On the completion of each review, the AEMC will report to the relevant jurisdictional Minister on its findings and recommendations on the need to continue or not retail regulation.

Other aspects of electricity retailing, such as marketing, dispute resolution and customer information requirements, are currently regulated by State and Territory governments.

All jurisdictions are working towards the implementation of a comprehensive national regulatory framework for non-economic regulation of electricity retailing. All Australian Governments have committed to the removal over the longer term of retail price regulation in the electricity sector, if markets are shown to be sufficiently competitive.

The National Electricity Market (NEM)

The transmission grids of New South Wales, Queensland, Victoria, South Australia and Tasmania are physically connected, and electricity can be traded across these jurisdictions on the wholesale NEM. The NEM is essentially a common set of trading and network access arrangements which allows generators and retailers to buy and sell electricity from the most competitive sources.

If a particular NEM Region has more electricity demand than can be met from their domestic supplies and another has excess capacity at a particular time, or if retailers can purchase cheaper electricity from another Region, electricity can be transported across regional boundaries through an 'interconnector' up to its maximum capability. An interconnector is a transmission network that connects the electricity grids of two Regions.

New South Wales is connected to the Snowy and Queensland Regions of the NEM. The Snowy-to-New South Wales transfer capacity is up to about 3,300MW in winter and 3,000MW in summer. New South Wales can also receive up to about 1,100MW from Queensland via the Queensland-NSW Interconnector (QNI), which runs between Armidale in New South Wales and Tarong in Queensland, and via Directlink, which runs between Mullumbimby and Terranora in New South Wales. When it has excess capacity, New South Wales can supply up to about 500MW to Queensland and 1,000MW to the Snowy Region. A map showing the NSW interconnectors is included in Chapter 2.

The National Electricity Market Management Company (NEMMCO) facilitates transactions on the NEM by operating a wholesale market. Generators offer specific quantities of electricity to the market at particular prices. NEMMCO dispatches generation by meeting demand in the most cost-effective way, dispatching the lowest cost generators first. Retailers then sell the electricity to end-users and it is transported to customers by the transmission and distribution networks.

A1.3 Précis of Submissions

Overarching Comments and Scope of the Inquiry

Most stakeholders welcomed the opportunity to make a submission to the Inquiry. Many appreciated that the tightening supply-demand balance in the National Electricity Market (NEM), along with recent national policy developments in the area of climate change, make it timely to undertake a forward-looking assessment of electricity supply options for New South Wales.

Several submissions expressed an understanding that it is the prerogative of the Government to assess whether the NEM can address projected supply shortfalls within the necessary timeframe. However, many emphasised that, while there is a role for the Inquiry in providing advice to the Government, private market participants are best placed to make ultimate investment decisions.

The majority of submissions appeared to accept the scope of the Inquiry, and provided commentary directly addressing the Inquiry's terms of reference.

However, some submissions were of the view that the terms of reference were overly restrictive, reflecting a preference for further investment in particular technologies (such as coal-fired generation) or projects of a certain scale, and suggested that the onus is on Government to demonstrate why new capital investment may be needed to meet growth in demand.

Several submissions commented that the terms of reference did not explicitly require consideration of options such as enhanced interconnection, energy efficiency measures, increased use of peaking and embedded generation, and improvements to electricity pricing structures, or of the effects of water shortages or new energy-intensive projects. Some submissions were of the view that the need for new generation should not be considered in isolation from a broader energy and climate policy framework.

In relation to the term 'baseload' generation, most submissions adopted the term as it is used throughout this report – that is, to refer to generation technologies that, for a mix of technical and economic reasons, optimally operate, at high capacity factors.

However, some submissions challenged the concept of baseload generation. These were of the view that baseload is an economic and engineering concept which was of greater relevance when electricity supply was centrally planned, prior to the market reforms of the 1990s. These submissions stated that, in the modern NEM, capacity and demand (as measured in megawatts) are more important considerations in 'keeping the lights on', and that this allowed for greater flexibility in addressing supply shortfalls.

Nonetheless, it was generally acknowledged that the concept of baseload remains relevant to the price of electricity, as the provision of too little baseload capacity would require extending the operation of more expensive peaking plant.

Terms of Reference 1:

Review the Need and Timing for New Baseload Generation that Maintains both Security of Supply and Competitively Priced Electricity

In relation to need and timing, most submissions referred to the National Electricity Market Management Company (NEMMCO) 2006 Statement of Opportunity (SOO) figures. However the submissions noted that since the 2006 SOO other committed capacity has been achieved and that rather than new capacity being required from 2010-11, their own or other modelling indicated a new capacity requirement from 2012-13.

Some submissions considered that the NEMMCO figures did not recognise the impacts of demand management and energy efficiency strategies, whilst others pointed to the risk of relying on such measures because demand reductions have not always been delivered as projected.

Given broad acceptance around the timing for new capacity being 2012-13, submissions differed more on the interpretation of the projection and the appropriate response, i.e. while the new capacity requirement is generally accepted, the NEMMCO projection is neutral as to whether the response should be baseload, peak or intermediate generation, and similarly is neutral to generation technology.

Many submissions reinforced that market investors are best placed to interpret the projections and make decisions accordingly, while noting that there would be a reluctance to invest until there is greater certainty in the regulatory framework. Regardless, most of the submissions that did address timing for additional baseload placed it in the period ranging from 2015 to 2020. This was based on the observation that peak demand is growing faster than energy growth.

Broadly it was considered that additional baseload generation was more a medium term need with additional peak and intermediate generation required from 2012-13.

Additional baseload was required to provide reliable and cost-effective electricity. Some submissions drew attention to the need for investments in distribution and transmission networks, not just additional generation, in order for there to be security in supply.

Terms of Reference 2:

Examine the Baseload Options Available to Efficiently Meet Any Emerging Generation Needs

There was recognition of the ability – and very strong support for – the market to determine the most efficient option for generation needs. There was much emphasis on the need for clarity in Government policy and regulatory settings in order to reduce uncertainties effecting technology choice and private sector funding.

There was broad recognition that the proven technologies for baseload generation are gas and coal, and that low emission technologies may not become commercially viable before the next uplift in generation capacity is required. Although the prospect of an emissions trading scheme has increased uncertainty around further coal generation, many pointed to the advantages of coal as being its low fuel cost, the substantial coal reserves, ease of transport and safe use. Consequently many pointed to the need to improve the efficiency of existing generation assets and to ensure the most efficient new coal-fired technologies were adopted. Careful consideration also needs to be given to water cooling technologies.

The desirability of renewable energy sources was acknowledged but most submissions did not consider it proven or economically viable for large scale generation within the timeframe for additional generation needs. Some submissions outlined a necessity to commence a move towards clean energy despite the continuing reliance on coal generation.

There was broad recognition of the potential for gas generation as the baseload option for the short to medium term, drawing on advantages such as smaller plant size, lower capital expenditure, less reliance on water cooling and shorter development time. In addition, having lower CO_2 emissions and being economic over a wider range of load factors weighed in its favour.

Many submissions pointed to known gas reserves that can support generation, although some noted that these reserves were predominantly located in Victoria and Queensland. Hence, should additional gas generators be located in New South Wales then additional pipeline infrastructure may be required. Others pointed to potential reserves in New South Wales. It was noted where there was deficient capacity there was willingness by the private sector to invest in the required infrastructure given the right incentives. Gas supply constraints were identified by some, referring to recent price volatility and the potential price impact of a gas only strategy.

A number of submissions noted that while demand management and energy efficiency measures play an important role in managing peak load or postponing new baseload commitments they would not be sufficient to meet emerging generation needs.

Terms of Reference 3:

Review the Timing and Feasibility of Technologies and /or measures Available Both Nationally and Internationally that Reduce Greenhouse Gas Emissions

Greenhouse gas emission reduction technologies

Submissions from stakeholders noted that gas-fired generation produces relatively lower levels of emissions in comparison with coal, however other submissions highlighted that all current fossil-fuel fired generation technologies produce substantial quantities of emissions and that gas should not be considered a low emission technology.

Some submissions considered the prospects for carbon capture and storage (CCS) technology but all stakeholders considered that it was unlikely that any technology would be commercially ready within the timeframe that NEMMCO has indicated new generation is required. However, a new asset could be made carbon capture 'ready' such that carbon capture technology could be added at a later stage.

Many submissions identified 2020 or beyond as the approximate timing for low emission technologies to start approaching commercial viability. A more diverse mix of technology options is anticipated in the future but only a few submissions believed that low emission technology is capable alone of meeting the immediate supply needs. In contrast a significant number of submissions, from a range of stakeholder viewpoints, specifically ruled out any prospect of renewable energy sources having the capability to meet the upcoming generation requirements. Stakeholders whose primary objective was to lower emissions whilst meeting new generation requirements generally supported combined cycle gas turbines.

Some submissions stated that nuclear power was not feasible within the current timeframe given the lack of a regulatory framework for nuclear power. Others noted that the costs of nuclear were uncompetitive with either gas or coal-fired generation. Another submission noted that nuclear was not supported by the community and any nuclear development might lead to civil unrest.

The absence of a known CO_2 storage site in New South Wales was noted as a major impediment to CCS and was used by some stakeholders to caution against building coal-fired generation.

Biomass co-firing is also an option for new plant to lower the greenhouse gas emissions intensity. Other forms of low emissions technology identified in submissions for consideration are wind, solar, hydro, geothermal, ocean wave and tidal and solar upgrades to existing coal-fired plant.

Submissions were strongly divided over whether NSW's upcoming energy requirements could and should be delivered by coal-fired, gas-fired or renewable energy sources.

Greenhouse gas emission reduction measures

Stakeholder submissions overwhelmingly supported the introduction of a national emissions trading scheme. The Commonwealth Government was identified by almost all stakeholders as the appropriate level of government to take the lead on the national scheme to ensure universality of the scheme. The current level of uncertainty around carbon prices is identified in almost all submissions as a key impediment to the private sector investing in generation assets.

Submissions are strongly focussed on the need for clear rules around the national emissions trading scheme before the private sector can invest in baseload. Stakeholders are also interested in certainty regarding the rules on transitioning from the New South Wales Greenhouse Gas Reduction Scheme to the national scheme.

A number of submissions provided views on the impact that different levels of the carbon price would have on the economic viability of gas vis-à-vis coal-fired generation, highlighting the uncertainty investors face given the lack of clear rules around a national emissions trading scheme.

A large number of submissions also stated that the Government should not pick technology winners or offer subsidies to one form of technology over another and instead should allow carbon trading to deliver the most competitive solution.

A few submissions raised concerns with the feasibility of meeting the State Plan interim emissions reduction target if a coal-fired power station was to be built in New South Wales.

Stakeholders from the gas industry have supported the introduction of minimum gas-fired generation requirements similar to the Queensland 18 per cent gas scheme. Submissions assert that this measure would encourage development of gas infrastructure in New South Wales. These stakeholders have also called for mandatory emissions performance standards at levels which would preclude coal-fired generation assets.

Submissions from the renewable energy industry supported the States and Territories renewable and low emission energy targets and schemes and some submissions raised the need for a national renewable energy scheme to ultimately come about. Stakeholders are divided on whether an emissions trading scheme would assist the development of a renewable energy industry or not.

Some submissions raised concerns with the number of State and Territory based schemes targeting greenhouse gas emission reductions and suggested that the range of schemes created further uncertainty in the industry. A number of submissions would prefer to see a moratorium on all State and Territory greenhouse gas emission reduction measures and a reliance on a single national emissions trading scheme.

Energy efficiency and demand management

Submissions from stakeholders made the following comments about energy efficiency and demand management and programs aimed at their enhancement. There is general consensus that enhanced energy efficiency has many economic benefits, in terms of delaying the need for new investment in generation, and in terms of lower electricity network costs. In addition, additional capacity could be delivered by reduced demand in the form of demand side participation.

Many submissions noted that market barriers are so significant that there is market failure in regard to energy efficiency and demand management. The market failure is largely due to ineffective price signals and lack of knowledge - energy consumers do not have a good understanding of how to reduce their energy bills. However, some also noted that the rules of the NEM also preclude effective demand side responses.

Some submissions have stated that the uptake of energy efficiency and demand management measures has been hampered even where it can be demonstrated that major cost savings would result. As a result, there is large untapped potential for energy efficiency in households and businesses. Submissions contained many suggestions on ways to unlock the potential.

For the industrial and commercial sectors, the following suggestions were made:

- energy performance assessment requirements for businesses should be expanded
- the greenhouse ratings for commercial buildings should be expanded and include non-office commercial buildings
- there should be mandatory public reporting of GHG emissions by website
- in commercial buildings, there should be more efficient lighting and heating, ventilation and air conditioning systems and the mass deployment of solar hot water heating.

For the residential sector, the submissions made the following suggestions:

- fast track the roll out of smart meters and require electricity retailers to offer of time of use tariffs
- expansion of Minimum Energy Performance Standards and more stringent energy labelling of appliances (to include plasma TVs, home entertainment products) and more stringent enforcement
- compulsory disclosure of energy ratings for houses at point of sale and leasing
- more stringent greenhouse and energy standards at the time of construction and renovation of houses, apartments and commercial buildings (supported by more stringent enforcement). This includes:
    - ramping up, and including higher rise buildings in Building Sustainability Index requirements
    - encouraging substitution of natural gas for electricity at the point of use, especially in space and water heating in both existing and new dwellings
- hot water systems: phase out and replace electric hot water heating by 2012 and mass deployment of solar hot water heating in residential buildings
- encourage solar photovoltaics by the use of 'feed-in' tariffs
- rebates to encourage households to convert from electric space heating to gas space heating, gas cooking, and to increase the installation of ceiling insulation.

Some submissions called for targeted efficiency measures to protect low income consumers, including increased education targeting low income users and improved standards for rental accommodation, particularly for water heaters and ovens.

Some submissions called for a nationwide energy efficiency target.

Terms of Reference 4:

Determine the Conditions Needed to Ensure Investment in and Emerging Generation, Consistent with Maintaining the NSW AAA Credit Rating.

There was a general consensus in the submissions that a lack a certainty of Government policy was creating an environment that was not conducive to private sector investment, particularly that of baseload investment. The clear articulation of Government energy policy is being sought by participants.

Most submissions pointed to the need for certainty over Government investment policy, with many pushing for a commitment to no further investment. There is a perceived risk that the Government will commit to new projects for non-commercial reasons in turn impacting upon the commercial viability of new and existing projects (i.e. stranding risk). The sale of existing Government owned generation sites is seen as a necessary initial measure by many submissions.

The lack of carbon pricing certainty was consistently and unanimously raised as a major issue, with most pointing to the need for clarity on this issue. Such uncertainty is a major contributing factor to the lack of appetite in the private sector to build new baseload plant because the future emissions regime and pricing remains so unclear. Most submissions supported a nationally based emissions trading scheme.

A number of submissions raised the issue of retail price caps with many calling for either more cost reflective tariffs or the abolition of retail caps altogether. The degree of price regulation was thought to be excessive and distortionary with many believing that retail prices were artificially low. Many submissions also pointed to the link between retail prices and revenue for generation investment, and highlighted the risk that inappropriate retail price regulation could stifle necessary investment. The winding down of ETEF was also considered important with some calling for this wind down to be accelerated.

The continuing public ownership by the NSW Government of generation and retail assets was thought to be problematic and the privatisation of the retail and generation assets was raised many times as a necessary condition for encouraging private sector investment. Many submissions expressed the belief that it was inappropriate for the Government to be competing in these markets and pointed to the uncertainty surrounding continued Government ownership and the problems that this was creating. The inability to gain critical retail mass exposure in the NSW market and the positive signal stemming from a sale of generation assets were often cited as reasons for privatisation.

Those submissions that supported continued Government ownership, pointed to the private sector as potentially being unreliable in delivering timely investment and being driven by profit-maximising motives to the detriment of consumers.

Some submissions pointed to the importance of timely and efficient planning assessment approval processes in aiding new investment projects, and expressed concern that these processes were unduly time consuming and uncertain.

A1.4 Submissions Received and Meetings Held

A. Submissions Received

AGL Energy Ltd

Alinta Limited

Alstom Power Ltd

ANZ Infrastructure Services

APA Group

Australian Business Council for Sustainable Energy

Australian Nuclear Science and Technology Organisation (ANSTO)

Australian Petroleum Production & Exploration Association Limited

Australian Wind Energy Association (Auswind)

Babcock & Brown Power Limited

BHP Billiton Petroleum Pty Ltd

Bioenergy Australia

Business Council of Australia

Carey, David

Cavanaugh, Janet

Citigroup Global Markets Australia Pty Limited

Clarence Environment Centre

Climate Change Australia, Hastings Branch

Cohen, Ian MLC

Council of Social Service of New South Wales (NCOSS)

Country Energy

Delta Electricity

EnergyAustralia

Energy Response Pty Ltd

A. Submissions Received (cont)

Energy Retailers Association of Australia Incorporated

Energy Supply Association of Australia

Energy Users Association of Australia

Epuron Pty Ltd

Eraring Energy

ERM Power

Geodynamics Limited

George Wilkenfeld & Associates

Grant, Ashley

Hunter Business Chamber

Hunwick, Richard

Hydrogen Energy

Integral Energy

InterGen (Australia) Pty Ltd

International Power Australia

Infrastructure Partnerships Australia

Kaye, John MLC

Labour Environment Activist Network

Macquarie Generation

Magaldi Power Pty Ltd

Major Energy Users Inc.

Metgasco Limited

Mousallem, Roujane

National Generators Forum

National Electricity Market Management Company Ltd (NEMMCO)

New South Wales Minerals Council

Origin Energy

Pardy, Lesley

A. Submissions Received (cont)

Property Council of Australia

Public Services International Research Unit, The University of Greenwich, United Kingdom

Public Interest Advocacy Centre Ltd

Queensland Gas Company Ltd

Richardson, Michael MP

Santos Limited

Sligar & Associates Pty Ltd

Sydney Chamber of Commerce

Sydney Gas Ltd

The Australian Pipeline Industry Association Ltd

The Climate Institute

Tomago Aluminium Company Pty Ltd

Total Environment Centre Inc., Nature Conservation Council of NSW & Greenpeace

Transfield Services (Australia) Pty Limited

TransGrid

TRUenergy Australia Pty Ltd

Unions NSW

United Services Union

Uniting Care NSW.ACT

Visy Pulp & Paper

Wizard Power Pty Ltd

WWF Australia

B. Stakeholder Meetings with Professor Owen

AGL Energy Ltd

Alinta Limited

Amalgamated Manufacturing Workers' Union

Association of Professional Engineers, Scientists and Managers

Australian Coal Association

Australian Energy Market Commission

Australian Industry Greenhouse Network

Australian Nuclear Science and Technology Organisation (ANSTO)

Australian Petroleum Production & Exploration Association Limited

Australian Pipeline Trust

Australian Wind Energy Association (Auswind)

Babcock & Brown Power Limited

BHP Billiton

Business Council of Australia

Business Council for Sustainable Energy

Construction Forestry Mining and Energy Union

Council of Social Service of New South Wales (NCOSS)

Country Energy

CSIRO Energy Technology Division

CSIRO Energy Transformed Flagship

Delta Electricity

Electrical Trades Union

EnergyAustralia

Energy Response Pty Ltd

Energy Retailers Association of Australia Incorporated

Energy Supply Association of Australia

Energy Users Association of Australia

Eraring Energy

B. Stakeholder Meetings with Professor Owen (cont)

Epuron Pty Ltd

Institute for Sustainable Futures

Integral Energy

International Power Australia

Macquarie Generation

Major Energy Users Inc.

National Generators Forum

National Electricity Market Management Company Ltd (NEMMCO)

National Emissions Trading Taskforce Secretariat

Nature Conservation Council of NSW

Origin Energy

Premier's Greenhouse Advisory Panel

Public Interest Advocacy Centre Ltd

Public Service Association

Santos Limited

Total Environment Centre Inc

TransGrid

TRUenergy Australia Pty Ltd

Unions NSW

United Services Union

Visy Pulp & Paper

WWF Australia

A1.5 Example of a Generation Cost Curve and Load Duration Curve

Baseload, intermediate and peaking plants provide 'scheduled' generation to the National Electricity Market (NEM). The market operator, the National Electricity Market Management Company (NEMMCO), schedules each plant to come into production to meet the prevailing demand, starting with the plant offering to supply electricity at the lowest price. The price at which each generator 'bids' into the wholesale electricity market generally reflects each generator's operating costs.

To demonstrate how costs affect the duration of supply from each type of plant[1] Figure 1.5.1 shows indicative cost curves for coal, combined cycle gas turbine and open cycle gas turbine technologies.[2]

Figure 1.5.1 is an indicative example that broadly reflects the generation mix in New South Wales. The availability of other technologies, and changes to the costs of coal and gas plant – for example, increasing fuel costs, the application of a carbon price, or technology-driven cost increases (such as the uptake of carbon capture and storage) – would affect where each technology sits in the spectrum of baseload to peaking plants.

The upper chart shows indicative cost curves of each type of plant, for different levels of plant utilisation (that is, the percentage of time each plant is operational). The curves take into account both capital and operating costs, and demonstrate that the longer a plant remains operational, the higher the costs of fuel, operation and maintenance. The curves rise at different rates, reflecting the different operating costs for each plant type.

The intersection of the cost curves with the cost axis is determined by the plant's capital (fixed) costs. Typically there is a trade-off between capital costs and variable costs, such as fuel. The higher the capital costs the lower are the variable costs. Which plants should be utilized for different periods of time is determined by this trade-off.

1 Based on NEMMCO load data for NSW in 2005-06.

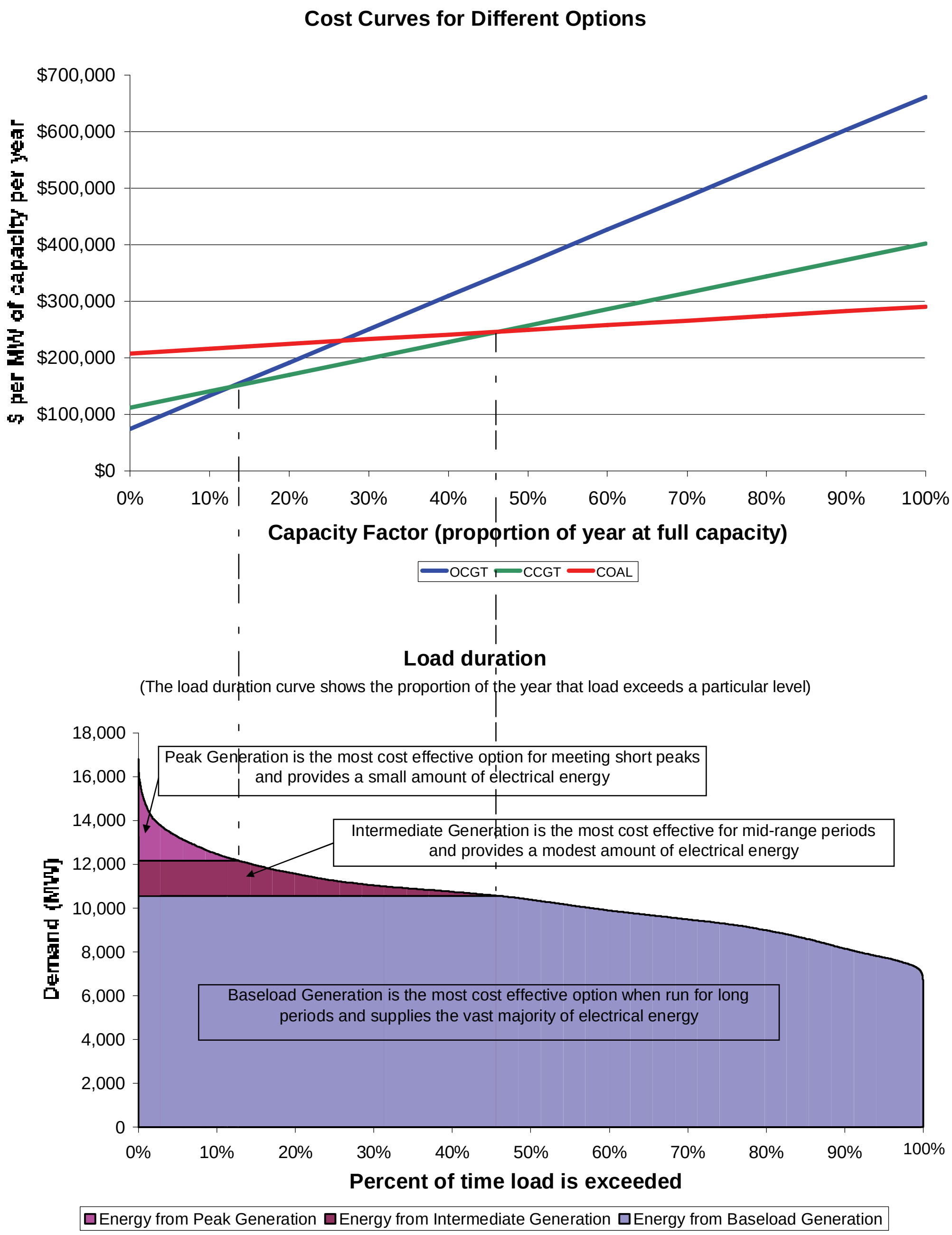
2 Based on ACIL Tasman draft report, *Fuel resource, new entry and generation costs in the NEM*, 27 March 2007, Report 2 - Data and Documentation.

The lower chart shows an indicative 'load duration' curve, which plots the percentage of time (over a year) at which demand reaches any given level.[3] The area under the load curve is the total amount of energy supplied.

Assuming that the generator with the lowest operating costs for each level of utilisation is the first one deployed to meet market demand, the two charts together show that in this example, coal-fired generation is the cheapest technology for higher levels of plant utilisation, running 100 per cent of the time. It would therefore provide baseload supply. Combined cycle gas turbines (CCGTs) would run at up to 45 to 50 per cent of the time. Open cycle gas turbines (OCGTs) would come online infrequently, running up to 15 per cent of the time, thus meeting peaking supply requirements.

[3] The actual NSW load curve is set out in Figure 2.3.1.

Figure 1.5.1: Indicative Generation Cost Curves and the Load Duration Curve



A2.1 Electricity Peak Demand - Trends and Forecasts

Maximum (peak) demand is the greatest instantaneous power level used at a particular time - usually occurring on a cold winter's evening or a hot summer's day. The maximum demand is usually measured in megawatts (MW).

NSW "scheduled" peak demand has grown relatively consistently over the last 30 years from about 6,000MW in 1976-77 to almost 14,000MW in 2007 (see Figure 2.1.1).

As shown in Figure 2.1.1, summer peak demand is growing faster than the winter peak demand. The historical growth in summer peak demand has not been linear. Historically, the summer peak demand has increased by an average of around 3.7 per cent on the previous year's summer peak demand.

Annual peak demand is much more volatile than annual energy consumption, as the conditions on the day and at the time of peak demand are much more variable. Peak demand will fluctuate depending on factors such as the actual weather conditions, (particularly in Sydney), and which day-of-the-week adverse weather conditions occur (weekend/school holidays/public holidays).

To cover the volatile nature of the annual peak demand, TransGrid prepare three peak demand scenarios to provide an understanding of the estimates. These are based on a 'Probability of Exceedence' (POE) criteria of the various load forecasts:

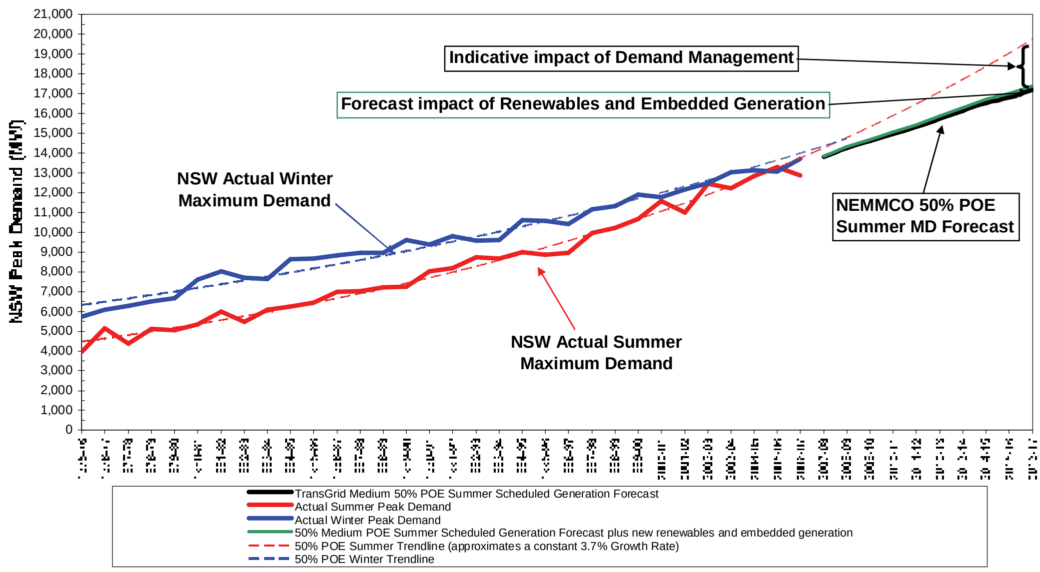
- 10 per cent POE is the forecast load not expected to be exceeded more than once every 10 years
- 50 per cent POE is the forecast load not expected to be exceeded more that once in two years
- 90 per cent POE is the forecast load not expected to be exceeded more than nine times every 10 years.

Figure 2.1.1 depicts the actual winter and summer NSW maximum demands over the past 30 years together with the forecast (50 per cent POE) summer maximum demand over the next 10 years. This forecast is lower than an extrapolation of the 50 per cent POE trend based on historical trends, due at least in part to demand management measures.

'Non-scheduled' embedded and renewable energy generation has only a small impact on peak generating requirements as the output of some of these generators, such as wind turbines, is somewhat volatile.

Demand management measures, such as planned load interruption and load shifting, along with peak price signals can however be quite effective in managing peak demand and contribute significantly to the forecast peak generating requirements being lower than the historical trend.

Figure 2.1.1: NSW Peak Summer/Winter Demand and Forecast, 1975-76 to 2016-17

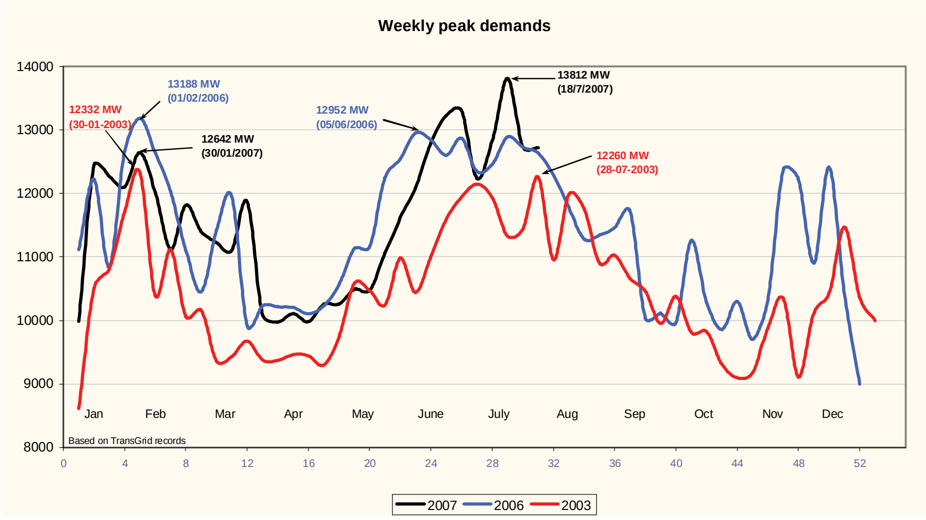


Source Data: TransGrid

There is obviously a degree of uncertainty around the exactness of the projections. Some submissions suggest that the NEMMCO/TransGrid forecasts for peak demand may be low, while others consider they may be too high. For example, Energy Response is of the view that peaks are rising at 4 per cent or more per annum. TransGrid/NEMMCO provide a 'high', 'medium' and 'low' scenario forecasts for projected 10 per cent, 50 per cent and 90 per cent POE demand.

Thirty years ago, the maximum peak demand in New South Wales was experienced in winter. However, New South Wales is now in transition from a winter to a summer maximum peak load region. The highest NSW maximum demand of 13,871 MW (17 July 2007) is still a winter, peak but prior to this winter the highest maximum demand was a summer peak (1 February 2006). NSW seasonal peak demand trends are shown in Figure 2.1.2.

Figure 2.1.2: NSW Summer and Winter Peak Demand – Seasonal Trend



Source Data: TransGrid

Peak demand does not drive the need for investment in baseload generation in itself. Rather, peak demand determines the need for new generation, such as open cycle gas turbines that can cost-effectively supply the short term peak requirements.

However, the distribution of peak demands can have an impact on the availability of baseload capacity at any particular time. The spread of high peak demands can impact the time available to baseload stations for maintenance.

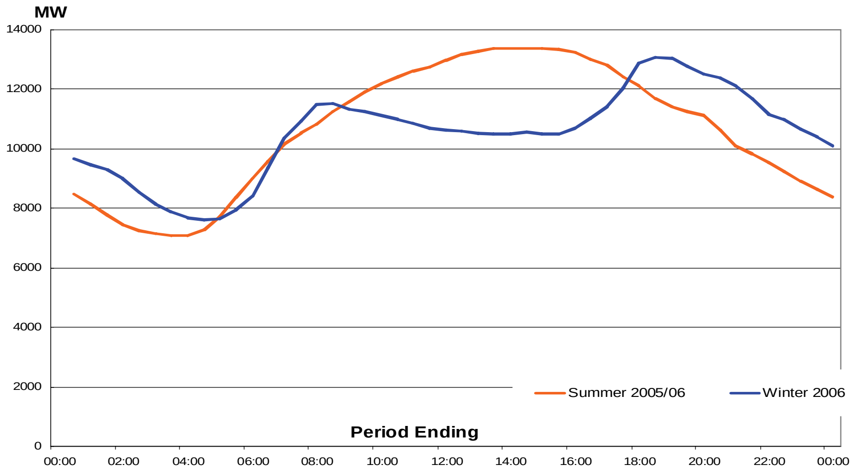
Over the past five years, the length of time that **seasonal peaks** can occur (summer and winter) appears to be extending over a wider number of weeks. This is tending to narrow the gap between those peak periods and conversely the length of the seasonal troughs (spring and autumn) is narrowing (see Figure 2.1.2). Generator and transmission system maintenance is traditionally scheduled during spring and autumn periods. Maintenance schedules are currently, and will continue to be, affected by this reduction in 'maintenance windows' and ultimately some maintenance may need to be carried out in peak periods, meaning that additional capacity may be required.

In autumn and spring 2006, there were only two months in each period where demand was reliably below 12,000MW. There are twenty large coal-fired generation units in New South Wales, and each of these requires a few weeks or more maintenance every 2-4 years, with additional shorter duration outages for minor maintenance in the in-between years, depending on the unit. Fitting this total maintenance need into these windows is now challenging.

The **daily load curve** compares demand against the time of day. During normal summer days the peak demand occurs in the late afternoon whereas peak load in winter occurs in the early evening (see Figure 2.1.3). This reflects different daily patterns of commercial, industrial and residential demand. In summer, the peak occurs earlier reflecting the overlap between business and industrial operations and the use of air conditioners in the commercial and residential sectors. The growth of air-conditioning use in schools and other educational facilities also contributes to the summer afternoon peak, with the air conditioners switched off once school finishes. In winter, the peak is driven by residential use of heating, cooking and lighting.

The magnitude and shape of the expected daily load pattern is a key factor in determining the forward generator dispatch requirement. This is planned and scheduled by NEMMCO to ensure sufficient generation is available and/or connected to cover the likely range of load requirements and to cover power system security needs.

Figure 2.1.3: Daily Load Curve[1]



1. Peak summer day 2005/6 and peak winter day 2006 actual load curves.

Source Data: TransGrid

On a 50 per cent POE basis, TransGrid projects summer scheduled maximum demand growth to average at about 2.5 per cent per annum over the next 10 years compared to the historic growth of around 3.4 per cent average over the past 10 years. On this basis, 17,200MW of scheduled capacity (see Table 2.1.1), plus a generation reserve margin, will be required to satisfy the scheduled maximum demand.

These NEMMCO forecasts include any major committed additional loads, but do not include any additional possible loads for major energy intensive users.

Table 2.1.1 details the historical and forecast NSW summer peak demands as set out by TransGrid in its 2007 Annual Planning Report.

Table 2.1.1: NSW Summer Demand Projections (Medium Scenario)

Summer	Actual	Scheduled (50% POE) (MW)	Embedded & Renewable (MW)	Total (50% POE) (MW)
1995-96	actual	8,879		
1996-97	actual	8,961		
1997-98	actual	9,966		
1998-99	actual	10,220		
1999-00	actual	10,662		
2000-01	actual	11,572		
2001-02	actual	10,990		
2002-03	actual	12,456		
2003-04	actual	12,216		
2004-05	actual	12,840		
2005-06	actual	13,292	284	13,576
2006-07	estimated	12,876	296	13,172
2007-08	projection	13,820	320	14,140
2008-09	projection	14,260	350	14,610
2009-10	projection	14,620	360	14,980
2010-11	projection	14,970	380	15,350
2011-12	projection	15,320	410	15,730
2012-13	projection	15,740	430	16,170
2013-14	projection	16,140	440	16,580
2014-15	projection	16,530	460	16,990
2015-16	projection	16,800	480	17,280
2016-17	projection	17,200	500	17,700
1995-96 to 2006-07		*363MW p.a.*		
2007-08 to 2016-17		*430MW p.a.*	*20MW p.a.*	*450MW p.a.*

Source: TransGrid, Annual Planning Report, 2007, p82 & p.27.

The forecast 10 per cent POE (or one in ten year) peak demands are between 1,200MW (2007/08) and 1,600MW (2016/17) above the 50 per cent POE (or one in two year) peak demands.

A2.2 Meeting Peak Demand

NEMMCO determines the generation requirements for each region by setting minimum reserve margins. The reserve margins are set so as to provide 0.002 per cent average unserved energy (USE), which is the reliability criteria provided to NEMMCO by the Australian Energy Markets Commission (AEMC) reliability panel. Unserved Energy refers to energy that would have been consumed had an unplanned interruption to supply not occurred.

NEMMCO determined the minimum reserve for the NSW region is minus 1430MW in 2007-08. The negative value for minimum NSW reserve reflects the capacity available to New South Wales from other NEM regions and demand diversity across the NEM regions and, in particular for New South Wales, access to the Snowy region's capacity. Diversity recognises that regional maximum demands may occur at different times.

In the 2006 Statement Of Opportunities (SOO), NEMMCO projected reserve shortfalls in New South Wales commencing in 2010-11 (see Table 2.2.1). Those projections include new generation and upgrades which met the NEMMCO commitment criteria by 30 June 2006 including a 440MW Combined Cycle Gas Turbine (CCGT) plant at Tallawarra. Two 30MW biomass fuelled co-generation plants under construction at the NSW Sugar Milling Co-operative sites at Condong and Broadwater will be registered as non-scheduled generating plant.

Table 2.2.1: Projected NSW Generation Shortfall in NEMMCO's 2006 Statement of Opportunities, 2008-09 to 2015-16

	Allocated Installed Capacity (MW)	Capacity for reliability (MW)	Additional Required Capacity (MW)
2008-09	14,495	14,049	-
2009-10	14,519	14,519	-
2010-11	14,682	15,009	327
2011-12	14,776	15,479	703
2012-13	14,853	15,919	1,066
2013-14	14,880	16,359	1,479
2014-15	14,803	16,789	1,986
2015-16	14,832	17,249	2,417

Source: NEMMCO Statement of Opportunities, 2006, Executive Briefing (graphically) and NEMMCO Solver Output

Note: These NEMMCO figures are on a 'sent out' basis (i.e. after deducting power station auxiliaries and own demand), rather than on the 'generated' basis used elsewhere in this Appendix.

Since the NEMMCO 2006 SOO, Delta Electricity has commenced construction of the Colongra 660MW Open Cycle Gas Turbine (OCGT) plant, at Lake Munmorah, which is expected to become operational by late 2009. This project will be included in the NEMMCO 2007 SOO as it now meets the NEMMCO commitment criteria.

Additionally a 640MW OCGT development is under construction at Uranquinty near Wagga. It is understood that 'financial close' for the Uranquinty plant was achieved in July 2007. The full contribution of Uranquinty to meet peak loads in New South Wales will be affected by its capacity to displace some Snowy generation. At or near peak load times Snowy generation is sometimes constrained by the Snowy – NSW transmission link. Uranquinty will need to share that transmission capacity.

As detailed in section 2.5 interconnection capacity with Queensland and the Snowy/Victorian regions is an important part of supply reserve capacity for New South Wales.

NEMMCO publishes the augmentation opportunities for interconnectors annually and prioritises these opportunities on the basis of net market benefit. These findings are presented in the Annual National Transmission Statement (ANTS) included by NEMMCO in the SOO. No significant increases in interconnection capacity have presently satisfied the required regulatory approvals process.

Minimum reserve level criteria

An alternative method of examining the required new generation capacity required to meet peak demands at an acceptable reliability is to use a minimum reserve plant margin benchmark – that is, a minimum amount of generation capacity that is available over and above the expected maximum demand.

From the 1960s through to the early 1990s, generation in New South Wales was planned and built to provide a relatively high reserve plant margin of at least 25 per cent. Improved plant reliability and electricity market drivers have allowed this margin to be significantly reduced without markedly compromising supply security. One of the main drivers for the establishment of the NEM was the realisation that Governments had over-invested in baseload plant, which had inflated electricity supply costs,[1] and the conclusion that prices and markets, rather than government, provided better outcomes on the need, type and timing for new generation capacity.

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[1] Industry Commission, *Report on Energy Generation and Distribution*, 1991 pp.37-38

A simply understood and an often internationally accepted minimum generation reserve standard is quoted as 15 per cent to 25 per cent of the maximum system load based on a 50 per cent POE load forecast. Application of that 'standard' to New South Wales, including interconnection capacity, results in very similar supply capacity shortfalls as the NEMMCO detailed market modelling process used in the SOO. A review of generation reserve levels was undertaken for NEMMCO in 2005 by KEMA. That report concluded:

'The target criteria level of the NEM, now set at USE of 0.002 per cent, appears to be consistent with that used internationally, but it is at the low end (less stringent than most others). The methods and approach of NEMMCO are generally consistent with international practice; the resulting reserve margin levels (15.9 per cent) are at the low end of international criteria (15-25 per cent)'.[2]

Also the Australian Energy Market Commission Reliability Panel is undertaking a comprehensive reliability review. The Panel's Interim Report in March 2007 [3]states:

'The raw results of international comparison are that the reliability standard in the NEM is lower (that is, less reliable) than in very large and highly-meshed power systems such as in the north east of the US but that it is in line with systems in European countries, from which the Panel concludes that the NEM reliability standard is at the lower end of international practice.'

The reliability panel went on to say:

'…On balance then, the reliability panel reached the view that, given Australia's unique demographics (a small population spread over large distances), the standard for reliability in the NEM is not inappropriate at the present time.'

Generation reserve is needed to cover the risk of some generating plant or interconnection capacity not being available at or near peak load times through such factors as plant maintenance or breakdown. Also it is assumed that this reserve would cover the more abnormal weather conditions that can occur (e.g. 10 per cent POE maximum demand conditions).

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[2] KEMA, *Review of Methodology and Assumptions Used in NEMMCO 2003/4 Minimum Reserve Level Assessment*, January 2005

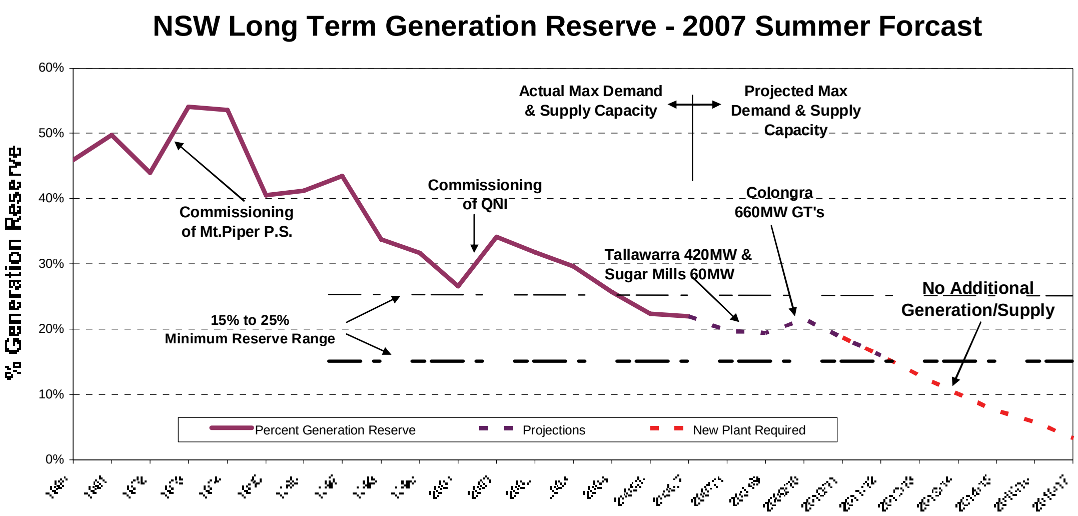
[3] Australian Energy Market Commission Reliability Panel, *Comprehensive Reliability Review Interim Report*, March 2007

New South Wales has not had less than a 15 per cent generation reserve margin, based on 50 per cent POE load forecast, since the early 1960s. Generation reserve in New South Wales is therefore now approaching levels not seen for over 40 years.

No major power stations have been built in New South Wales since Mt Piper power station was completed in 1993 (see Figure 2.2.1). However, the commissioning of interconnection with Queensland (QNI) in 2001 increased NSW supply reserves as it allows electricity to be supplied to New South Wales from generators based in Queensland.

Power stations which are currently being constructed at Tallawarra, Colongra and the North Coast sugar mills will ensure reserve levels remain steady until after 2010-11.

Figure 2.2.1: NSW Generation Reserves



Source Data: TransGrid and ESAA

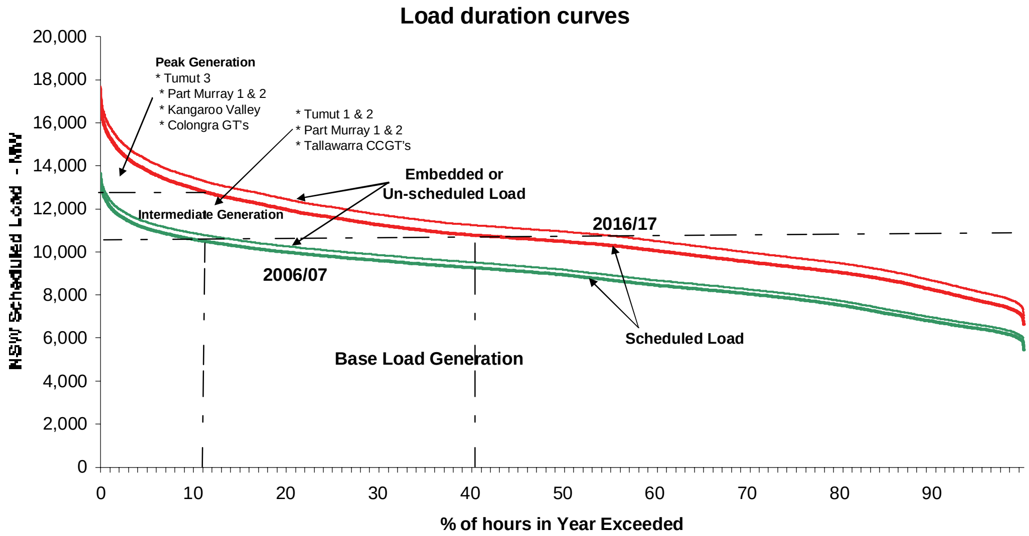
The anticipated new generation requirements using this 15 per cent capacity margin criteria are consistent with NEMMCO's forecast capacity requirements.

A2.3 Mix of Existing NSW Plant Types

When considering both supply reliability and commercial efficiency, the mix of plant available for generation is important. An optimal mix of plant maximises efficiency and keeps costs at a minimum.

Like all power systems NSW supply is provided by a mix of base load, intermediate and peak load generation. Historical and projected "load duration curves" (see Figure 2.3.1) provide an indication of what part of the supply mix various generation sources provide to New South Wales. In this chart, the split between peak (OCGTs), intermediate (CCGTs) and base load (coal-fired) generation is based on technology cost data from ACIL Tasman's March 2007 report to NEMMCO. This costing split would be expected to change with the introduction of an emissions trading scheme, as CCGTs are less carbon intensive than OCGTs or coal-fired plant, and so would enjoy a relative price advantage.

Figure 2.3.1: NSW Load Curve, Actual and Projected



Source Data: TransGrid

Figure 2.3.1 presents a simple comparison of different types of plant. However, comparing unit costs in isolation does not identify what mix of plant is commercially efficient for a particular market. Other variables also need to be considered, including inter-State transmission effects, the effect of increasing renewables capacity in response to mandated targets and demand management activities.

Historically, energy generated by Snowy Hydro has supplied the major peak and intermediate generation needs for New South Wales. Some under-utilised older coal-fired plants, such as Munmorah, have also provided part of the reserve generation mix. Increased demand and energy consumption growth is now requiring NSW plant to achieve higher levels of energy generation than ever previously achieved. Delta Electricity advised the Inquiry that in its present condition the Munmorah power station cannot provide a normal baseload role and major expenditure will be required at Munmorah within five years for it to resume a more normal baseload role.

While the different plant types (baseload, intermediate and peaking) can all be technically suitable to meet baseload demand, how they operate in response to demand will be determined by commercial drivers and fuel availability. Different plant types are subject to different operating costs, primarily as a result of fuel requirements and, in the near future, carbon prices. Plants that have relatively lower operating costs will generally provide the bulk of energy supply, while plants that have relatively higher operating costs tend to limit their operation to periods of higher energy demand and consequently higher prices.

The operating behaviour of individual plants is also affected by the flexibility with which they can operate. Coal-fired power stations require a longer time to start up (between 12-20 hours) and to ramp up or down in response to demand fluctuations. This characteristic means they usually continue running even during periods of low demand (e.g. during the night). Various measures to shift demand to these periods in order to lower peak demand have been used, such as off-peak hot water heating.

A2.4 Interstate Transmission Augmentation Potential

The availability of supply from generators located outside New South Wales could be increased by augmentation and/or duplication of the existing interconnectors. However, the additional cost of increased interconnection capacity and transmission losses adds significantly to the cost of supplying NSW needs from interstate generation. If other factors are equal, generation is most cost-effective if sited in reasonable proximity to the load it is supplying.

In its submission to the Inquiry, TransGrid offered the following comments on increased interconnection capacity:

> ‘At times of high system demand these interconnectors are typically heavily loaded, with power normally being imported into NSW. Loading on the interconnectors during lower load periods is determined by bidding strategies of market participants’[4]

With regard to Queensland-New South Wales Interconnector (QNI), TransGrid comments:

‘TransGrid and Powerlink Qld are currently assessing a potential upgrade of the import capability of QNI. This assessment is being undertaken under the “market benefits” limb of the Regulatory Test.

The current analysis in progress indicates that an upgrade of the import capability to NSW to around 1500MW may be justified, but these studies indicate this is unlikely before around 2011 at the earliest. The optimum timing of such an upgrade depends on generation developments within both NSW and South-eastern Queensland.’[5]

[4] TransGrid submission, p3.

[5] Ibid, p4.

Further in a section on 'Reliance on New Generation in South-East Queensland', TransGrid comments:

'The generating sites in South-East Queensland are some 700km from the Hunter Valley and significant transmission development would be required to access this generation. … It would be necessary to construct an entirely new transmission line route from Queensland down to (probably) the Tamworth/Armidale area and then onto the Hunter Valley. … The additional costs associated with these options may be as much as $1.7 billion. … Losses as high as 10-15 per cent could be expected for base load power transfers from Queensland to the Newcastle, Sydney and Wollongong area.'[6]

Allowing for increased levels of energy to be supplied to New South Wales from Queensland in around 10 years time, will require significant developments of new power stations in that State possibly together with major transmission expenditure to increase the capacity of QNI. Increased transmission losses from such an arrangement to deliver base load energy to New South Wales' major load centres from Queensland could be around 10 to 15 per cent. This could make development of this nature unlikely.

With regard to additional Western / Southern Generation TransGrid comments:

'…The cost of this work is in addition to transmission line costs outlined in section 5.5 [section5.5 of TransGrid's submission - Bannaby to Sydney augmentation] and are likely to be in the order of $1 billion. …. Significant transmission development would be required to access this generation.'[7]

With regards to increased Transfer Capacity from the Snowy/Victoria regions TransGrid comments:

'The majority of the network development required for an expansion of generation in the Western and Southern parts of the State ….would be required and significant works south of that point, including in Victoria.'[8] (No cost estimates were offered for those significant works).

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[6] Ibid, pp7-8.

[7] Ibid, p9.

[8] Ibid, p9.

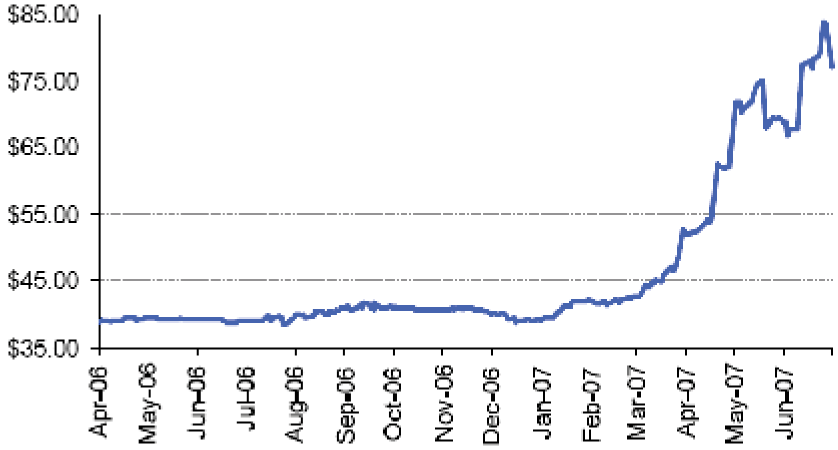
At best, the benefits from potential augmentations to QNI and to the Vic-Snowy-NSW interconnectors identified in NEMMCO's 2006 Annual National Transmission Statement (ANTS) have been classed by NEMMCO as 'Marginal' to 'Insufficient'. On this basis, the Inquiry does not believe it is appropriate to include them in the consideration of required generation.

A2.5 Impact of Energy Shortages on Wholesale Electricity Price

Electricity market conditions in recent months have highlighted the potential for wholesale prices to increase as electrical energy becomes scarce. Whilst the drought has had little impact on peak generating capacity, it has led to a reduction in the amount of electrical energy that is available from baseload and intermediate plants due to constraints on the amount of water available for cooling and for hydro generation. The energy shortage created by the drought is analogous to an energy shortage that may be experienced if new baseload generation was not built in a timely enough fashion.

The severity of the drought, and the possibility that constrained water supplies could impact generation capacity factors, significantly affected the forward market contract price for 2008 and beyond (see Figure 2.5.1). Further, prices increased significantly for both peak and base contracts. Even though the availability of peak generation capacity was relatively unaffected by drought conditions, the prospect of energy shortages pushed the forward market contract prices to around double previous levels.

Figure 2.5.1: Calendar year 2008 baseload contract price graphed against the date the contract was written[9]



[9] Source: Sydney Futures Exchange

A2.6 Process for Addressing Energy Supply Shortfalls

Development paths for new baseload generation options require specific activities to be undertaken to ensure a project is delivered, which meets intended needs, budget and timing requirements. These activities include:

1. Recognition of the need for new capacity or market opportunity.
2. Identifying a suitable site or sites well located in relation to fuel supply, transmission, with sufficient land area and buffer zones to minimize impacts on local residences, and likely to be able to achieve acceptable licence and planning conditions.
3. Undertaking preliminary technical and environmental baseline studies to confirm a preferred site.
4. Undertaking detailed studies to confirm technical feasibility and ensure capability to meet known licensing requirements.
5. Undertaking the planning approvals process to secure Development Approval and obtain required licences.
6. Undertaking market analysis to confirm financial viability and timing requirements.
7. Committing to project activities required to design, specify, award contracts, construct, commission and achieve commercial operation.

For the purposes of this report it is recognized that the **Activities 1 to 4** above have essentially been completed for a number of identified coal-fired and gas-fired sites.

Activity 5 is complete or in process for some gas-fired sites identified, but is not yet started for any of the coal-fired sites. Given that this activity can be protracted particularly in the case of a coal-fired plant this represents a key risk to any coal-fired development. Accordingly, consideration needs to be given to commencing the planning approval process for at least one coal-fired option as soon as possible so as not preclude that type of development by 2013-14 at this time.

Activities 6 and 7 will be undertaken by investors (Government or private) in the normal course of business.

A2.7 Environmental Planning and Assessment

A Possible New Base-Load Power Generation Facility in New South Wales

Environmental Planning Process

Application of Part 3A

On 1 August 2005, the Government's 'Major Project' legislation came in to force to provide a single, focused and integrated environmental planning and approval process for major infrastructure and development in New South Wales. These significant reforms, implemented through Part 3A of the *Environmental Planning and Assessment Act 1979*, replace and improve the assessment processes formerly applying to State significant development (Part 4) and major Government infrastructure projects (Division 4, Part 5). Significantly, Part 3A maintains the rigour of the environmental assessment and breadth of public involvement previously required, while substantially reducing the 'procedural red tape' of earlier assessment processes. The Minister for Planning is the approval authority for all Major Projects under Part 3A.

Part 3A of the *Environmental Planning and Assessment Act 1979* provides that a development may be declared to be a Major Project through a State Environmental Planning Policy, or through a project-specific Order made by the Minister for Planning. Relevantly for major electricity generating facilities, clause 24, Schedule 1 of State Environmental Planning Policy (Major Projects) 2005 declares the following to be Major Projects:

'Development for the purpose of an electricity generation facility that:

- has a capital investment value of more than $30 million for gas or coal-fired generation, or co-generation, or bioenergy, bio-fuels, waste gas, bio-digestion or waste to energy generation, or hydro or wave power generation, or solar power generation, or wind generation, or
- is located in an environmentally sensitive area of State significance.'

Note: 'environmentally sensitive areas of State significance' are defined in detail in the Policy, and include areas such as coastal wetlands, Ramsar wetlands, National Parks, heritage areas and critical habitats, inter alia.

It is therefore likely that a new baseload power station in New South Wales would constitute a Major Project, and would be assessed and determined by the Minister for Planning under Part 3A of the *Environmental Planning and Assessment Act 1979*. It is also important to note that as at June 2007, the Department of Planning was considering a number of possible amendments to *State Environmental Planning Policy (Major Projects) 2005*, including addition of 'distillate' as a relevant fuel under clause 24, Schedule 1 of the Policy.

Part 3A process

The Part 3A process generally includes:

- An inquiry and application phase, during which the Department of Planning and other relevant public authorities are briefed on the project and identify key environmental assessment requirements
- An Environmental Assessment preparation and review phase, during which the proponent prepares an Environmental Assessment to address key environmental assessment requirements, and the Environmental Assessment is reviewed by the Department of Planning and other relevant public authorities to ensure adequacy
- A public exhibition and submission, during which interested parties are invited to consider the Environmental Assessment and to make a submission on the project
- A submissions response phase, during which the proponent is required to respond to issues raised in submissions through a Submissions Report or Preferred Project Report
- A final assessment phase, during which the Department of Planning finalises its assessment of the project and makes a recommendation to the Minister for Planning, who determines the application

The basic Part 3A process is illustrated below.

Initial inquiry and confirmation of Part 3A process

Part 3A Application and Preliminary Assessment
preliminary identification of key assessment issues prepared by the proponent

Director-General's requirements for Environmental Assessment
prepared by Department of Planning in consultation with relevant public authorities
maximum 28 days

Preparation of Environmental Assessment
prepared by Proponent to address Director-General's requirements

Review of Environmental Assessment adequacy
undertaken by Department of Planning in consultation with relevant public authorities
maximum 21 days

Public exhibition of Environmental Assessment
minimum 30 days, but may be extended for complex projects or projects subject to a high level of public interest

Preparation of Submissions Report/ Preferred Project Report
prepared by Proponent in response to issues raised in submissions (Submissions Report) and may include amendments to the project (Preferred Project Report)

Director-General's Report and Conditions of Approval
prepared by Department of Planning
Proponent and relevant public authorities consulted on recommended conditions of approval

Minister for Planning considers and determines application

There are a number of matters that have the potential to significantly affect the duration of the environmental planning and assessment process, beyond the minimum statutory timing requirements. These matters include:

- The rigour of the site selection process undertaken by the proponent. Careful and well-considered site selection can, in many cases, avoid or minimise potentially significant environmental impacts associated with a particular project. By taking environmental planning considerations into account during the site selection process, a proponent can potentially resolve a number of key environmental concerns that may arise with poorly-selected sites. In the case of a baseload power station, for example, consideration of factors such as the proximity of noise-sensitive receptors, airshed constraints and cumulative air quality impacts, the significance of any vegetation that may need to be cleared, and the nature of transport routes (road and rail) can make the difference between a well- and a poorly-selected site.
- The rigour of consultation undertaken by the proponent with affected and interested stakeholders during preparation of the Environmental Assessment. Consultation with affected and interested stakeholders during preparation of the Environmental Assessment assists a proponent in identifying key community concerns at an early stage and provides an opportunity for the proponent to proactively address these concerns as part of the project. In the absence of effective consultation, fundamental issues may be raised in public submissions that were not previously identified by the proponent, resulting in the need for additional work at the Submissions Report/ Preferred Project Report to address these issues.
- The rigor of consultation undertaken by the proponent with the Department of Planning and relevant public authorities during preparation of the Environmental Assessment. Effective consultation with key regulatory agencies during the preparation of the Environmental Assessment can ensure that assessment requirements are clear and fully understood, and that established assessment guidelines, policies and practices are taken into account. In the absence of effective consultation, the Environmental Assessment may not adequately address the Director-General's requirements and may need to be revised and updated prior to public exhibition.

Special provisions under Part 3A

In addition to the basic Part 3A process outlined above, the Minister for Planning has the discretionary power to:

- Authorise or require the submission of a Concept Plan
- Direct that an Independent Hearing and Assessment Panel be convened
- Declare a project to be a Critical Infrastructure Project.

Concept Plans

Authorisation or requirement for a Concept Plan permits a proponent to submit the basic scope and assessment of a project upfront, and for a bankable, in-principle agreement to be granted ahead of detailed design and assessment. It is important to note that a Concept Plan must still demonstrate that a proposal can be undertaken within acceptable environmental and public health and amenity standards, but provides an opportunity for a proponent to provide details of the project and its impacts through a subsequent project approval process (as distinct from the initial concept approval process). A Concept Plan is particularly useful in the case of large or complicated proposals, or where the details of a proposal may be subject to further consideration in future, for example in technology selection or tender processes where innovation may be required. In granting approval to a Concept Plan, the Minister for Planning may concurrently grant project approval for all or part of the proposal, and may specify the planning process and assessment requirements for subsequent project approval phases.

A Concept Plan does not permit a development to be undertaken without obtaining a subsequent project approval, but it does, however, provide up-front certainty ahead of expending resources on the detailed design of a project. Once a Concept Plan is approved, project approvals are bound to be granted consistent with the Concept Plan. In the case of a base load power station, a Concept Plan may include:

- A Concept Plan that includes multiple site options in the same general region
- A Concept Plan approval that could potentially be granted across those multiple sites, with the decision on a preferred site only required at the project application stage
- Consideration of a number of different generating technologies, or fuel sources, with the final decision on the preferred technology and fuel only required at the project application stage
- Consideration of various implementation/ timing options, with a project application for each stage/ phase made subject to market demands in future.

There are a number of examples of where the Concept Plan process has been successfully applied (available on the Department of Planning's website, www.planning.nsw.gov.au) including:

The **Munmorah gas-fired power station**, involving a gas-fired power station, a gas pipeline and subdivision of land:

- The Minister for Planning approved the Concept Plan, to provide a basis for the overall proposal and its components
- Full project approval for the gas-fired power station component under Part 3A
- Stipulation that the subdivision of land would require further assessment and approval under Part 4
- Stipulation that the gas pipeline would require further assessment and approval under Part 5, and specification of the environmental assessment requirements for that process.

The **Kurnell Desalination Project**, involving a desalination plant, intake/discharge infrastructure and a pipeline for the supply of desalination water. The Minister for Planning approved the proposal as follows:

- Approval of the Concept Plan, to provide a basis for the overall proposal and its components
- Full project approval for the desalination plant and intake/ discharge infrastructure under Part 3A
- Stipulation that the desalinated water distribution pipeline would require further assessment and approval under Part 3A
- Specification of the environmental assessment requirements for that process.

The **Bamarang gas-fired power station**, involving a two–stage gas-fired power station (open cycle in stage 1, and combined cycle in stage 2), and gas and electricity transmission infrastructure. The Minister for Planning approved the proposal as follows:

- Approval of the Concept Plan, to provide a basis for the overall proposal and its components
- Full project approval for stage 1 of the proposal (open cycle configuration) and associated gas and transmission infrastructure under Part 3A
- Stipulation that stage 2 of the proposal (conversion to combined cycle configuration) would require further assessment and approval under Part 3A, and specification of the environmental assessment requirements for that process.

Independent Hearing and Assessment Panels

The Minister for Planning also has the power to direct that an Independent Hearing and Assessment Panel be convened to advise the Minister on specific aspects of a proposal. In directing that a Panel be convened, the Minister may specify the terms of reference for the Panel and any particular procedural requirements for the Panel process. In most cases, the Panel process will involve consultation with key stakeholders and submitters, through a hearing process, roundtable meetings or other mechanism required by the Minister. Examples of recently completed Panel processes (available on the Department of Planning's website, www.planning.nsw.gov.au) include the coal export terminal on Kooragang Island and the Anvil Hill coal mine.

Critical Infrastructure Projects

The Minister for Planning may also declare a project to be a Critical Infrastructure Project, where the Minister considers that the project is 'essential to the State for economic, environmental or social reasons. It is important to note that a Critical Infrastructure declaration does not affect the timing of the statutory Part 3A process, the rigour of the environmental assessment, or the level of community consultation undertaken. It does, however, provide certainty by extinguishing appeal rights to the Land and Environment Court. The declaration also excludes the potential for Orders to be made under some other environmental legislation (for example, stop work orders and interim protection orders). To date, the Minister for Planning has declared the following proposals to be Critical Infrastructure Projects:

- The Kurnell desalination project
- The Western Sydney groundwater bore-fields projects
- The Pacific Highway upgrade projects
- The Hume Highway upgrade projects
- The Hexham to Queensland gas pipeline
- Upgrade of the North Shore Hospital
- Upgrade of the Liverpool Hospital

Environmental Impact Assessment

Any proposal to establish a new baseload power station in New South Wales will require an environmental impact assessment. Key environmental impacts and assessment requirements for such a project can be generally grouped as follows:

- those impacts associated with the nature of the project (technology- and fuel-dependent)
- those impacts associated with the nature of the site selected for the project, including proximity to surrounding receptors.

Impacts associated with the nature of the project can be generally addressed and managed through careful consideration of the appropriate fuels and a generating process consistent with best available technology. In some situations, particularly constrained air-sheds or locations near residential and sensitive receptors, site selection may also interact with fuel and technology selection.

Impacts associated with the nature of the site can often be resolved or minimised through careful and considered identification of potential project locations, and selection of a preferred site based on criteria including environmental planning issues and constraints. Effective consultation with local communities and regulatory agencies will often assist a proponent to identify the key opportunities and constraints that may apply to a site, or a region.

Impacts associated with the project

Key impacts associated with the nature of fuel and technology selected for a base-load power station are likely to include:

- greenhouse gas implications
- air quality impacts
- noise and vibration impacts

Air quality impacts

Possibly the most significant local/ regional impact with any emissive power generation proposal, and the impact of key concern to affected communities, will relate to air quality impacts. Choice of fuel will affect the nature and concentration of air emissions: the use of a natural gas fuel will produce oxides of nitrogen as the principal air quality concern, while coal or distillate fuel sources will also produce particulates and oxides of sulphur. Similarly, selection of technology, including the scale and efficiency of the technology and any associated air pollution control equipment applied to the technology would affect the air quality performance of the proposal.

It should be noted that with respect to air quality, site selection will play a significant role in the impacts of the proposal and the need for additional technology-based solutions to address these impacts. For example, urban airsheds may be constrained with respect to oxides of nitrogen and associated ozone generation. Therefore, an emissive power generation proposal in an urban airshed is likely to be confronted by more significant airshed constraints than a proposal in a more rural setting. Depending on the scale of the proposal, the nature of the technology and the chosen fuel, these constraints may or may not be economically and feasibly resolvable.

Similarly, an emissive power generation proposal near existing power generating developments or major emissive industry may be constrained through cumulative air quality impacts. Co-location of power station projects (or with industrial developments) may result in a more complicated air quality impact assessment and mitigation approach, compared with development of a 'greenfield' site away from established power generators and industry.

Noise and vibration impacts

Selection of technology will also influence the acoustic characteristics of the proposal, including the transport related noise implications of fuel provision. For example, haulage of distillate by road, supply of gas by pipeline and transport of coal by rail may generate significantly different acoustic characteristics. The nature of the power generation technology will also influence noise impacts, and the potential for these noise impacts to be mitigated through design solutions.

In this context, site selection will also play an important role in noise and vibration impacts. Location of a new base load power station away from noise-sensitive receptors or other noise-generating development may reduce the need for additional noise mitigation measures to be applied in order to meet acceptable environmental outcomes. Key noise-related issues associated with power stations will also include tonal or impulsive noise impacts, and the potential for exacerbated noise impacts under adverse (temperature inversion) meteorological conditions. Site selection taking into account these potential issues may act to simplify the assessment of acoustic impacts and the need for additional mitigation.

Impacts associated with the site

Key impacts associated with the nature of the site selected for a base-load power station may include:

- ecological impacts
- impacts on Aboriginal and European heritage
- water supply, water quality and hydrological impacts
- ancillary infrastructure impacts
- visual amenity implications.

As previously highlighted, an effective and comprehensive site selection process can, in many cases, resolve environmental assessment issues relating to the nature of a particular development site. Investigation of environmental constraints, whether ecological, heritage or hydrologically-related, prior to the selection of a preferred site, will often assist in selecting a site with fewer constraints and fewer issues to be considered and resolved through the assessment process. Given the current drought conditions over much of New South Wales, water availability will be a key issue, and a strong focus should be placed on accessing any alternative (non potable) water sources close to the project site (for example, recycled water from industry or sewage treatment, where feasible).

In selecting a site, consideration should also be given to the nature of any land that may be affected by new or upgraded ancillary infrastructure, including gas pipelines, transmission lines, water supply infrastructure or road/rail infrastructure. While a particular development site may be relatively free from environmental constraints, areas likely to be affected by infrastructure also need to be considered in the site selection process.

In addition to environmental constraints, site selection should also consider human receptors, particularly residential and sensitive land uses, which may be impacted through air quality, noise, traffic and socio-economic effects. Visual amenity issues, particularly where a new baseload power station is to be located in visually sensitive landscapes or with clear views to visually-sensitive receptors, may also be significant and require further consideration of screening options.

A3.1 Potential sites for the Storage of CO_2 in NSW

The GEODISC program of the Australian Petroleum Cooperative Research Centre (CRC) explored potential sites for carbon capture and storage in Australia from 1999-2003. It identified and mapped sites suitable for the geological storage of CO_2, based on a simple saline aquifer model. The Australian Petroleum CRC was replaced by the Cooperative Research Centre for Greenhouse Gas Technologies in 2003 and since that time, the centre has been undertaking more detailed storage assessments, including—risk assessments to ensure that the CO_2 could be safely and permanently disposed of in the deep subsurface. The Centre developed a *Technology Roadmap* for both capture and geological storage of carbon dioxide with an Australian focus.

There are four identified options for the storage of carbon dioxide:

- Storage in depleted petroleum and gas reservoirs
- Injection into deep uneconomic coal seams
- Mineral Carbonation
- Injection of CO_2 into deep saline aquifers (deep saline water-saturated reservoir rocks).

Of these options for the permanent sequestration of CO_2, two hold little promise of being applicable in New South Wales in the short term because:

- there are no depleted oil and gas fields in New South Wales, and
- mineral carbonation is at a very early stage of research.

Storage in coal beds presents a number of issues and their potential storage capacity may not be sufficient for storing the very large volumes of CO_2 emitted by NSW power plants. However, even relatively small storage options close to existing power stations may be advantageous.

The disposal of CO_2 into deep saline aquifers is considered to have the most potential for sequestration of large volumes of CO_2 in New South Wales.

In New South Wales a lack of significant petroleum exploration has resulted in a lack of knowledge of the geology and hence the storage potential of NSW deep sedimentary basins. Because the GEODISC project only assessed publicly available information it did not identify any significant opportunities for carbon sequestration in New South Wales. This created a belief that New South Wales did not have suitable sites.

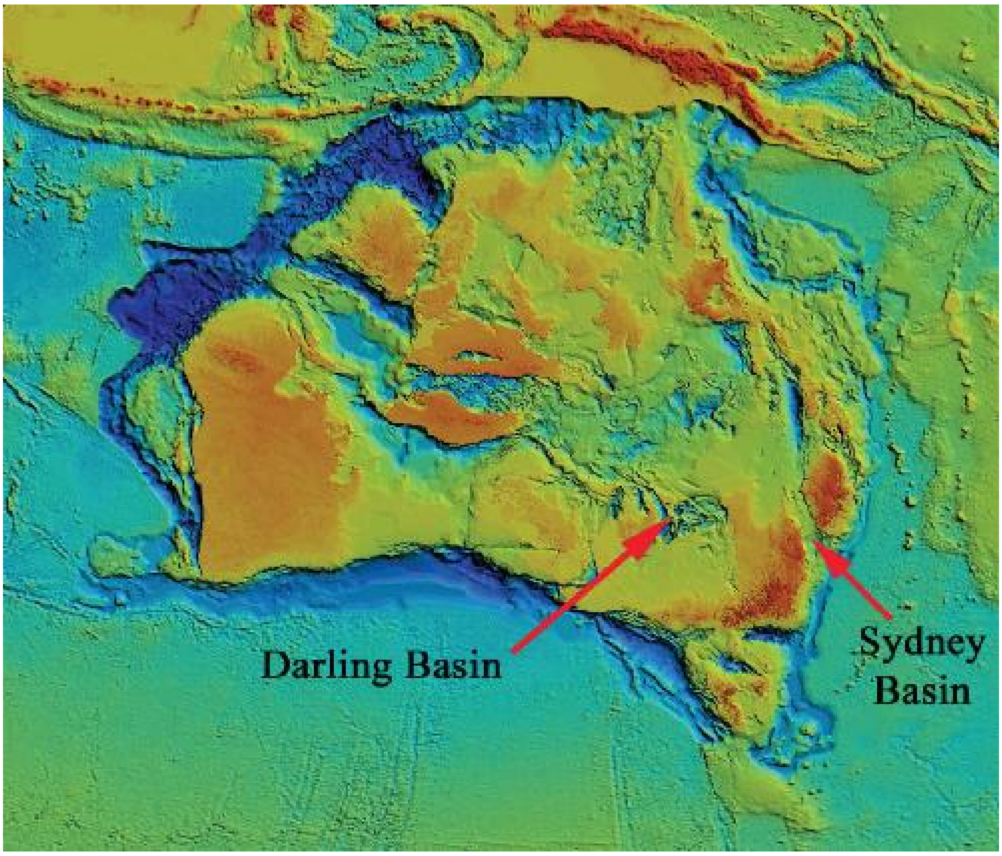
However, a more detailed assessment of the available information suggested that there may be significant potential for geosequestration in New South Wales. To address this issue more detailed studies of two basins, the Darling and the Sydney Basin, were commissioned.

Darling Basin

Initial results from these more detailed studies have shown that the Darling Basin in central New South Wales has significant potential for the large scale storage of CO_2 into deep saline aquifers.

A total of 16 areas of interest have been identified in the basin as having reservoir and seal potential at subsurface depths appropriate for CO_2 sequestration. Refer to Figure 3.1.1 below which shows the Darling and Sydney Basin's and relative depth to basement.

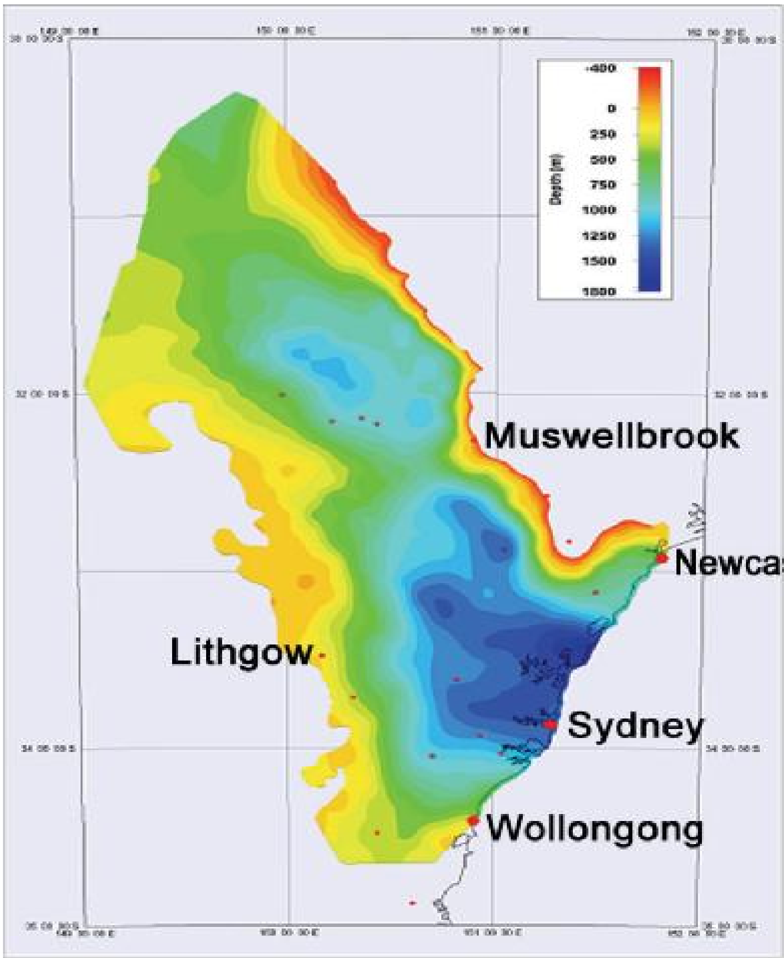
Figure 3.1.1: Australian Sedimentary Basins Depth to Basement (Blue represent deeper areas)



Sydney Basin

Initial results from the Sydney basin study indicate that there may be storage potential within deep coal seams and the surrounding sandstones, although low permeabilities are expected to represent a challenge. It may be necessary to apply different models, and perhaps new technologies, such as long reach horizontal wells to the eastern half of New South Wales, where the sedimentary basins are complex and dominated by coal sequences. Storage potential may be better in the western side of the basin and further north in the Gunnedah basin where reservoir quality is predicted to improve. However, further more detailed work will be required to ascertain whether there are opportunities for carbon capture and storage in New South Wales. Refer to Figure 3.1.2 which shows potential areas for geosequestration in New South Wales.

Figure 3.1.2: Potential areas for geosequestration in the Sydney Basin (Blue areas indicate depths suitable for geosequestration)



Other Areas

Detailed studies are being conducted on the storage potential of a number of other basins, including the Gunnedah, Clarence-Moreton, Murray (Oaklands) and the Sydney basin. The results of these studies will not be available for some time.

Currently the NSW Government has committed funds to a pilot geosequestration project which involves an assessment of the storage potential of NSW basins. The project is expected to take place over five years. Initial stages will involve geophysical studies, drilling, site characterisation, geological modelling leading to a pilot injection at a selected site at around year five.

A4.1 Demand Management Initiatives and Options

NSW Demand Management Code of Practice and the D-Factor

The NSW *Electricity Supply Act 1995* requires distribution network service providers (DNSPs) to investigate and report on demand management strategies when it "would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion [of a distribution system] by implementing such strategies".[1] The NSW Demand Management Code of Practice ('the Code') provides guidance to DNSPs in meeting this requirement.

The Code is part of the framework for the economic regulation of NSW electricity distribution networks administered by IPART.

In June 2004, IPART issued its *NSW Electricity Distribution Pricing 2004-05 to 2008-09 Final Determination and Final Report*. A key component of the Determination was the introduction of a number of incentives to promote network demand management. As part of its Determination, IPART introduced a 'D-Factor' into the weighted average price cap control formula. This allows DNSPs to recover:

- Approved non-tariff-based demand management implementation costs, up to a maximum value equivalent to the expected avoided distribution costs (as defined in the determination)
- Approved tariff-based demand management implementation costs
- Approved revenue foregone as a result of non-tariff based demand management activities.

IPART's demand management incentives aim to reduce the 'peakiness' of electricity demand in order to improve the utilisation of DNSPs' assets and lower their capital expenditure.

According to IPART, the Determination provides relatively generous incentives to DNSPs to undertake demand management. IPART considers that this level of incentive is required, at least in the short-term, to help overcome the barriers to greater use of demand management and to support the emergent market for these solutions.

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1 *Electricity Supply Act 1995* (NSW), Schedule 2, s6(5)

IPART requires DNSPs to submit information demonstrating how the demand management projects they have implemented reduce network expenditure. These projects should reduce electricity demand at peak times to defer the need for network augmentation. The DNSPs must demonstrate that their demand management implementation costs are less than or equal to the avoided distribution costs before it can pass through any costs to customers.

The framework for the D-factor demand management program is expected to change with the transfer of economic regulation of the NSW distribution network service providers to the new national governance arrangements.

The Australian Energy Regulator, the new national energy market regulator, will be required to develop and publish a demand management incentive scheme to provide incentives for distribution companies to maintain and improve efficient performance. The details of this incentive scheme are still to be determined.

Savings to date and future projections

The DNSPs provide information to IPART in relation to the D-Factor on a commercial-in-confidence basis. As a result, it is difficult to measure the impact of the D-Factor to date. Anecdotal evidence suggests that although there was a positive response to the D-Factor in its first year of operation (2004-05), investment in demand management by the DNSPs decreased in the second year (2005-06).

IPART is due to release a report in late 2007 on the D-Factor and an assessment of the first two years of its operation. The report is expected to provide more detail on its impact on demand management and, in turn, on the overall demand for electricity.

Despite the lack of formal data, there is evidence that DNSPs have invested in demand management programs. For example, in August 2006, Integral Energy had approximately 15 demand management projects under consideration.[2] Further information can be found at www.ipart.nsw.gov.au.

[2] Integral Energy, *Network 2016*, August 2006.

Greenhouse impacts of demand management

Demand management projects aim to shift demand from peak periods to off-peak periods. As such, they provide financial benefits from reduced infrastructure needs but they do not necessarily reduce overall energy consumption.

Baseload electricity in NSW is generally provided by coal-fired generation. Peaking power is increasingly by lower emission forms of generation such as natural gas. Demand management programs, which shift demand from peak periods to non-peak periods therefore, may have the effect of increasing emissions of greenhouse gases.[3]

Facilitating demand-side measures through the National Electricity Rules

An option raised in the submissions to the Inquiry is for Governments to take action towards encouraging voluntary and autonomous demand management in the National Energy Market.

An example of such activity is provided by Energy Response Pty Ltd, a demand-side response (DSR) aggregator, in its submission to the Inquiry. Energy Response reports that it can offer at least 300MW of firm DSR capacity in New South Wales almost immediately, with about half of this available within four hours notice and at a fraction of the cost of new peaking generation capacity. It is reported that an active DSR program in the NEM can achieve efficiency benefits of 20 per cent and end-users who participate in the programs directly benefit through payments that offset the cost of their electricity.

The Inquiry notes that the Ministerial Council on Energy (MCE), in conjunction with the Australian Energy market Commission (AEMC), is currently undertaking a large body of work related to demand-side response.

The reform work is focusing on a number of provisions of the National Electricity Rules where existing arrangements may explicitly or inadvertently deter or prevent DSR and options for simulating greater levels of DSR in the NEM. This work is examining opportunities for more demand-side response for both distribution and retail activities.

[3] That said, there is some evidence that measures aimed at enhancing demand management can also result in lower electricity consumption. For example, in its submission to the Inquiry, EnergyAustralia reports that its introduction of smart meters and time of use (ToU) tariffs to small business customers has had the following results (page 22). ToU customers used, on average, 7 per cent less electricity in peak/shoulder periods than the non-ToU customers, and 1 per cent less electricity overall that non-ToU customers.

The outcomes of this work will inform the need for changes to the regulatory arrangements for the NEM, including possible amendments to the National Electricity Rules (NER). The NSW Government is an active participant in the reform process. This also relies heavily on consultation with industry and end-users groups.

A5.1 Greenhouse Gas Emission Reduction Policies in Australia

There are a large number of policies in place in Australia designed to address the issue of emission of greenhouse gases in the generation of electricity. Some are national, but many more are State based policies. This Appendix provides an overview of both current and proposed greenhouse policies in Australia.

The policies are of various types. Some are market based policies, where market participants choose the least cost means of meeting legislated targets of emissions reductions. Others are policies aimed at promoting a particular type of fuel to generate electricity, such as renewables or natural gas. The aim of these policies is to produce lower levels of greenhouse gas emissions than is produced from current coal-fired generation plants.

A third type of policy is the provision of funding to facilitate research and development and deployment of technologies that will reduce greenhouse gas emissions.

As noted above, the market based policies are based on legislated targets of emission reduction. The following section outlines the targets announced by the Commonwealth and State Governments.

Targets for Reduction of Greenhouse Gases

NSW committed to greenhouse gas emission targets in June 2005. The NSW targets are:

- a 60 per cent reduction on 2000 levels by 2050, and
- a return to 2000 levels by 2025.

The Commonwealth Government has committed to the introduction of a national emissions trading scheme. Once in place, the long run target, and annual caps, that the Commonwealth Government defines for the national scheme will also become the targets for all States and Territories.

Other jurisdictions have adopted similar long-term targets and these are detailed in Table 5.1.1. Further, First Ministers of all States and Territories have agreed through the Council of Australian Federation that 'a national emission trading scheme should place Australia on a path towards achieving a 60 per cent cut in national emission by 2050 compared to 2000 levels'[1] These targets are broadly in line with the targets adopted overseas (See Table 5.2.1 in Appendix 5.2).

The Commonwealth Government has not yet adopted a target for reducing greenhouse gas emissions. As part of *Australia's Climate Change Policy*, the Commonwealth Government has indicated that it will set a long-term aspirational goal in 2008 and short-term caps for an emission trading scheme in 2010.

Most Australian jurisdictions have introduced legislation which targets the level of electricity consumption to be met by renewable energy sources. The States' renewables targets are much higher than the Commonwealth's as can be seen in Table 5.1.1. The Commonwealth requires renewable forms of energy to provide an additional 2 per cent of the nation's electricity generation capacity by 2010, while New South Wales has a 10 per cent total renewable target in 2010 rising to 15 per cent by 2015. Queensland has also introduced a target to produce 18 per cent of its electricity from natural gas. Table 5.1.1 summarises the targets for greenhouse gas reduction and for renewables and other lower emission fuels that have been introduced in Australia.

[1] All First Ministers adopted this target at the Council for the Australian Federation (CAF) meeting on 12 April 2007 in Canberra. See p3 of corresponding communiqué.

Table 5.1.1: Greenhouse gas reduction and renewable/low emission targets, by Australian Jurisdiction

Jurisdiction	Long-term (2050) economy-wide targets	Intermediate economy-wide targets	Renewable or low emission targets
Commonwealth Government	No policy. (To be announced in 2008.)	Annual caps for period up to 2020 for an emission trading scheme to be announced in 2010.	2% extra renewable energy target by 2010 (legislated)
New South Wales	60% reduction on 2000 levels	Return to 2000 levels by 2025	10% renewable energy target by 2010 and 15% by 2020
Victoria	60% reduction on 2000 levels		10% renewable energy target by 2016 (legislated)
Queensland	60% reduction on 2000 levels		18% gas generation by 2020 and 10% low emission target by 2020
South Australia	60% reduction on 1990 levels (legislated)		20% renewable energy target by 2014 (legislated)
Western Australia	60% reduction on 2000 levels		15% renewable energy target by 2020 and 20% by 2025
Tasmania	60% reduction on 2000 levels		
Australian Capital Territory	60% reduction on 2000 levels	Return to 2000 levels by 2025	Implement a renewable energy target in line with NSW.

Policies Aimed at Meeting Emission Targets

The announced emission targets are substantial and will require the implementation of well designed policies if they are to be achieved. Government policies designed to reduce greenhouse gas emissions are of three main types – market based approaches, such as emissions trading schemes, policies promoting low emission forms of energy, and funding programs. The following section outlines the major policies currently implemented or being developed in Australia.

Market based policies

There is one market based policy currently implemented in Australia which aims to reduce greenhouse gas emissions, the NSW Greenhouse Gas Reduction Scheme (GGAS).

A national emissions trading scheme will be established in Australia, no later than 2012. This will replace GGAS. The background to the establishment of a national emission trading scheme is as follows:

- The States and Territories established the National Emissions Trading Taskforce (NETT) in January 2004. The NETT published a detailed design framework in August 2006, *Possible Design for a National Greenhouse Gas Emissions Trading Scheme*[2]. The work of the NETT is described below.
- The Prime Minister's Task Group on Emissions Trading (PM's Task Group) was formed in December 2006 and reported on 1 June 2007[3]. Its design largely followed the proposals of the NETT. Its work is described below.
- The Commonwealth Government formally responded to the PM's Task Group report on 17 July 2007 when it issued *Australia's Climate Change Policy*[4]. Through this policy the Commonwealth endorsed the need for an emission trading scheme as the primary mechanism for achieving greenhouse gas reductions in Australia. This policy also endorsed the key design features of the emission trading system set out in the PM's Task Group report. These key features are described in Chapter 5.

(i) NSW Greenhouse Gas Reduction Scheme (GGAS)

The NSW Greenhouse Gas Reduction Scheme (GGAS) was one of the first mandatory greenhouse gas emissions trading schemes in the world. GGAS started operating in January 2003. Since that time, it has created the second largest mandatory carbon market in the world.

GGAS aims to reduce greenhouse gas emissions associated with the production and use of electricity and to encourage participation in abatement projects, that is, activities to offset the production of greenhouse gas emissions, such as reafforestation.

GGAS places responsibility on retailers[5] and wholesale market customers to reduce emissions associated with electricity used in New South Wales and the Australian Capital Territory.

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2 National Emissions Trading Taskforce, *Possible Design for a National Greenhouse Gas Emissions Trading Scheme*, 2006

3 Department of Prime Minister and Cabinet, Prime Ministerial Task Group on Emissions Trading, *Report of the Task Group on Emissions Trading*, 2007

4 Australian Government, *Australia's Climate Change Policy*, July 2007

5 Including some generators acting as retailers. Large users of electricity can also elect to take responsibility to reduce the greenhouse gas emissions associated with their electricity use, in lieu of their retailer.

GGAS provides certainty to markets by introducing a price signal for greenhouse gas emission abatement across the National Electricity Market (NEM). GGAS reduces greenhouse gas emissions by providing a financial incentive for lower emission generators and abatement projects. Since the scheme began in 2003, the total number of all abatement certificates surrendered to meet obligations is equivalent to about 30.5 million tonnes of carbon dioxide equivalent[6]. Because it is a state-based scheme embedded in the NEM, GGAS allows the low emission generators and abatement projects to occur in New South Wales, Queensland, Victoria, South Australia, Tasmania and the Australian Capital Territory.

Unlike some other greenhouse gas emissions trading schemes - such as the European Union Emission Trading Scheme (EU ETS) and the proposed National Emission Trading Scheme (NETS) - GGAS is a baseline and credit scheme. As most liable parties do not directly emit greenhouse gases from electricity production, their attributable emissions are calculated from an emissions baseline.

GGAS establishes annual state-wide greenhouse gas benchmarks for the NSW electricity sector. It requires liable parties (called Benchmark Participants) to meet their allocation of the mandatory greenhouse gas benchmark, based on their share of the NSW electricity demand.

Liable parties reduce emissions relative to the baseline by creating or purchasing credits (called NSW/ACT Greenhouse Abatement Certificates or NGACs) from abatement projects. Such projects include:

- low-emission generation of electricity (including cogeneration) or improvements in emission intensity of existing generation activities
- activities that result in reduced consumption of electricity
- activities that reduce on-site emissions not directly related to electricity consumption
- the capture of carbon from the atmosphere in forests.

A Benchmark Participant pays a financial penalty if it fails to surrender enough abatement certificates to meet their mandatory benchmark. Currently the penalty level is set at $12 per tonne of shortfall (pre-tax, effective for the 2007 compliance year).

[6] Independent Pricing and Regulatory Tribunal of New South Wales 2007, *Compliance and Operation of the NSW Greenhouse Gas Reduction Scheme during 2006*, 2006, p 12.

The NSW Independent Pricing and Regulatory Tribunal (IPART) administers the GGAS and is also the NSW Compliance Regulator. More detailed information on GGAS is available from the GGAS website: http://www.greenhousegas.nsw.gov.au.

NSW policy is for GGAS to end once a national emissions trading scheme is implemented. This will require appropriate transitionary measures.

(ii) National Emissions Trading Scheme (NETS)

In January 2004, First Ministers of State and Territory Governments established a working group of senior officials to develop a model for a national emission trading scheme. With its experience establishing GGAS, the NSW Government led the work on developing the NETS.

In December 2004, the senior officials, now known as the National Emissions Trading Taskforce (NETT) reported key design elements. In August 2006, the NETT published a detailed discussion paper on the *Possible Design for a National Greenhouse Gas Emissions Trading Scheme*.[7] The Commonwealth was invited to participate in this process. Key features of the proposed NETS include:

- Use of a Cap and Trade mechanism, with permit issue limited to annual targets. Firm targets would be set for the first 10 years and a range or 'gateway' of targets for the next 10 years
- Start from 2010 and remain in place for at least 20 years
- Based on the electricity sector initially, with expansion to the rest of the stationary energy sector from 2015. Note that since the Discussion Paper the NETT is now considering broader scheme coverage. In addition to electricity generation and other stationary energy – fugitive emissions, industrial process emissions, transport and possibly waste are all being considered
- Transitionary compensation (free permits) to disadvantaged generators (e.g. coal plant)
- Compensation (free permits) to trade-exposed energy intensive, industries (e.g. aluminium smelters) until overseas competitors face similar carbon prices
- Auction of remaining permits with proceeds to go to jurisdictions.

[7] NETT, *Possible Design for a National Greenhouse Gas Emission Trading Scheme: A Discussion Paper prepared by the National Emission Trading Taskforce*, August 2006.

The Discussion Paper proposed two long-term targets for the electricity sector for 2030 under three indicative scenarios[8]:

- **Scenario 1**: 176 Mt (equal to emission levels in 2000)
- **Scenario 1a**: 176Mt (Scenario 1), plus large-scale exogenous energy efficiency programs
- **Scenario 2**: 150 Mt (equal to emission levels in 1997)

These targets were chosen to generally place the electricity generation sector on a path to achieving a 60 per cent reduction on 2000 levels by 2050.

Under these scenarios, modelling indicates that permit prices at the start of the scheme will lie within a range of \$5 to \$12/tCO_2, depending on the scenario. The permit price is forecast to rise to between \$15 and \$30/tCO_2 by 2020 and peak at up to \$35/tCO_2.

In February 2007, the Council for the Australian Federation (CAF) comprising First Ministers from all States and Territories called on the Commonwealth Government to introduce an emissions trading scheme in collaboration with the States and Territories, otherwise the States and Territories would introduce it themselves by the end of 2010.

Approximately 120 submissions on the Discussion Paper were received from a diverse range of stakeholders and were generally very supportive. The most common comments were that the scheme should include broader coverage and that it would be beneficial to secure Commonwealth Government involvement. There were also requests to examine more stringent caps than appeared in the Discussion Paper.

The NETT has continued to refine the scheme design during 2007 and anticipates publishing a final report later in 2007. This report may recommend the expanded scheme coverage described above and may contain modelling to take this expanded coverage into account.

Further information on the NETS is available at www.emissionstrading.net.au.

[8] NETT, op.cit

(iii) Prime Minister's Task Group on Emissions Trading and Australia's Climate Change Policy

The report of the Prime Minister's Task Group on Emissions Trading was released on 1 June 2007. The PM's Task Group agreed that a national emissions trading scheme was appropriate for Australia. The Commonwealth Government formally responded to the PM's Task Group report on 17 July 2007 when it issued *Australia's Climate Change Policy*. Through this policy the Commonwealth endorsed the need for an emission trading scheme as the primary mechanism for achieving greenhouse gas reductions in Australia.

This policy also endorsed the key design features of the emission trading system set out in the PM's Task Group report. These key features are described in Chapter 5.

The PM's Task Group was asked to advise on the nature and design of a workable global emissions trading system in which Australia would be able to participate. This allowed consideration of a domestic emissions trading scheme that might operate in advance of a truly global arrangement.

The PM's Task Group was chaired by the Secretary of the Department of Prime Minister and Cabinet. Its members included representatives from Commonwealth departments such as Treasury, Environment and Heritage, Foreign Affairs and Trade, and Industry, Tourism and Resources, as well as major companies including Xstrata, International Power, Australian Pipeline Trust, Qantas, BHP Billiton, Alumina and the National Australia Bank. There were no representatives from the States and Territories. The PM's Task Group's terms of reference did not require it to have regard to the work of the NETT.

The design framework outlined in the report is very similar to that developed by the States and Territories NETS process. The PM's Task Group recommended that Australia should not wait until a global agreement has been reached on emissions reductions, but implement a domestic emissions trading scheme in 2011 or 2012 at the latest. Major features of the recommended design framework which parallel the NETS approach include:

- Endorsement of a cap and trade style emissions trading scheme
- Broad scheme coverage, including all major greenhouse emitting sectors except for agriculture and land use
- The need for a long term target – though the PM's Task Group recommends that it be 'aspirational' and not set until 2008.
- The need for firm annual caps in the first ten years and indicative medium term ranges (or gateways) in the following ten years.

Although the PM's Task Group report broadly follows the key design features of the NETS, there are some points of differentiation. The most important of these include:

- **Long-term targets are aspirational only**: the PM's Task Group report has made no comment on what the long term aspirational target should be. The Commonwealth Government has stated that these will be set in 2008.
- **Complementary measures**: both the PM's Task Group report and the NETS recognise the role of various complementary policies. However, the Task Group report does not support renewable energy targets. In fact, it questions the role of schemes that have already been legislated, such as VRET and recommends that schemes which have been announced but not yet legislated, such as NRET, should not proceed. Since the publication of the PM's Task Group report, the States have reaffirmed their commitment to their respective renewable and low emission targets. Queensland has announced that its 13 per cent target for gas-fired generation will be increased to 18 per cent.

Renewable and Low Emission Energy Targets

The Commonwealth introduced the Mandatory Renewable Energy Target (MRET) in April 2001. Since then several States have introduced similar schemes based on legislated targets for the contribution to electricity supply by renewable energy sources[9]. These renewable targets may increase electricity prices as a certain percentage of electricity consumption will need to be met by more expensive renewable sources (principally wind).

The rationale for these schemes is one of industry development for an interim period (until approximately 2030). Under an emissions trading scheme, the carbon price in early years may not be sufficient to drive large-scale deployment of renewable energy technologies. Renewable energy targets are used to accelerate this development and ensure that new technologies are available for when deep cuts are required in later years.

[9] Actual targets are expressed as a fixed GWh target in each year. The Commonwealth target applies Australia wide. State targets are additional, but are applied in that State. A project cannot claim credits under both Commonwealth and State schemes, for the same generation.

Commonwealth Mandatory Renewable Energy Target (MRET)

For electricity, the Commonwealth's major greenhouse program is the Mandatory Renewable Energy Target (MRET or the 2 per cent Renewable scheme), which requires electricity retailers to purchase around 9500 GWh of extra renewable electricity per year by 2010 through to 2020.

MRET is described as having two purposes – to encourage investment in renewable energy technologies and to reduce greenhouse gas emissions. The quota of renewable energy projects required by MRET has now been met, so no further investment will be driven by the scheme.[10]

NSW Renewable Energy Target (NRET)

On 9 November 2006, the Premier announced mandatory renewable energy targets for NSW. The New South Wales Renewable Energy Target (NRET) will require 10 per cent of electricity consumed in NSW by 2010 to come from renewable energy sources in the NEM. By 2020, the figure will rise to 15 per cent and remain at this level until 2030. Of the total electricity from the NEM consumed in NSW, 6 per cent is currently sourced from renewable energy, predominantly from the Snowy hydro scheme.

In order to create an incentive to use renewable energy, electricity retailers who fail to reach the targets will face a penalty set at a level higher than the cost of purchasing renewable energy certificates. The legislation implementing NRET was introduced into the NSW Parliament on 27 June 2007 in anticipation of the scheme starting on 1 January 2008.

It is intended that the NRET design mirrors that of the Victorian scheme discussed below.[11]

Victorian Renewable Energy Target (VRET)

Victoria was the first State to announce a State-based target. The Victorian Renewable Energy Target (VRET) requires 10 percent of the electricity consumed in Victoria to come from renewable sources in Victoria by 2016. At present, renewables contribute around 4 per cent of Victorian electricity.

VRET commenced on 1 January 2007 and is legislated to operate until 2030.[12]

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[10] Further information on the MRET is available at www.greenhouse.gov.au/markets/mret.

[11] It is intended that the NRET design mirrors that of the Victorian scheme discussed below.

[12] Further information on the VRET is available at 222.esc.vic.gov.au/public/VRET.

Queensland Gas Scheme and Renewable and Low Emissions Energy Target

The Queensland Gas Scheme commenced on 1 January 2005 and will operate for 15 years. It provides incentives to build new gas-fired generation capacity by requiring a certain proportion of Queensland's electricity supply to be sourced from gas-fired generation. Eligible fuels are natural gas, coal seam gas (including waste coal mine gas), liquefied petroleum gas and waste gases associated with conventional petroleum refining.

In June 2007 the Queensland Government announced a new package of greenhouse measures. This includes reiterating the long-term 2050 target of a 60 per cent reduction on 2000 levels. To achieve this, the previous 13 per cent target for the Queensland Gas Scheme will be increased to a target of 18 per cent by 2020.[13]

In addition, a new 10 per cent renewable and low emissions energy (which will include "clean coal") target by 2020 has also been announced.

Australian Capital Territory Climate Change Strategy

The ACT Climate Change Strategy sets a target of a reduction by 60 per cent of 2000 emissions by 2050, with an interim milestone of limiting 2025 emissions to 2000 levels. The strategy includes a range of programmes targeting greenhouse gas reduction including a renewable energy target similar to the recently announced NSW renewable target.[14]

Western Australian Climate Change Action Statement

In May 2007, the Premier of Western Australian announced a Climate Change Action Statement.[15] This includes:

- an aspirational 50 per cent Cleaner Energy Target (CET) for the South West Interconnected System (SWIS) by 2010 and 60 per cent by 2020. This includes gas and renewable energy generation.
- renewable energy targets of 15 per cent by 2020 and 20 per cent by 2025 for the SWIS.

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[13] Further information on the Queensland Gas Scheme is available at www.energy.qld.gov.au/13 percentgas.cfm

[14] Further information on the ACT's Climate Change Strategy is available at http://www.tams.act.gov.au/live/sustainability/climate/climatechangepolicyunit

[15] Further information is available at http://portal.environment.wa.gov.au.

South Australian Climate Change and Greenhouse Emission Targets

South Australia has legislated[16] an economy wide goal of a 60 per cent reduction on 1990 levels by 2050, and has a renewable energy target of 20 per cent by 2014.[17]

Funding for research, development and deployment of low emissions technologies

In addition to market based approaches, such as emissions trading schemes, and regulatory approaches, such as legislated targets for renewables and low emissions technologies, a third type of government policy – funding specific types of projects - has been widely used in Australia to address greenhouse gas emissions.

Many Australian governments provide funding for the research, development and deployment of low emission technologies, including renewable sources of energy and energy savings. The aim is to facilitate the entry of low emissions technologies into the market place in situations where the uptake of such technologies may not be high. These types of funding programs are common and have been used by many Governments, both within Australia and overseas.

For example, the NSW Government has established the $310 million Climate Change Fund. It includes a $40 million Renewable Energy Development Program for pilot and demonstration projects, such as solar and geothermal power stations.

In addition, the NSW Government has also announced $22 million in funding for two pilot clean coal projects. The first project will identify potential carbon storage sites, to be followed by a pilot carbon capture and storage project. The second is a contribution to an ultra clean coal demonstration plant at Cessnock.

The Commonwealth Government also provides funding for research, development and demonstration of low emissions and renewables technologies. The Low Emissions Technology Demonstration Fund ($500 million) is designed to demonstrate break-through technologies with significant long-term greenhouse gas reduction potential in the energy sector.[18]

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[16] The Climate Change and Greenhouse Emissions Reduction Act 2007 became law on 3 July 2007.

[17] Further information is available at www.climatechange.sa.gov.au

[18] Details are at http://www.greenhouse.gov.au/demonstrationfund/.

The Renewable Energy Development Initiative ($100 million) offers grants between $50,000 and $5 million for research and development and early-stage commercialisation projects with high commercial and greenhouse gas abatement potential.

The Queensland Government has announced a $300 million Queensland Climate Fund which will be used to develop new technologies such as clean coal and hydrogen fuel cells.

The Western Australian Government has announced a $36.5 million Low Emissions Energy Development Fund to promote emission reduction and support emerging technologies.

A5.2 International Greenhouse Gas Reduction Policies

Introduction

This Appendix outlines the key features of various greenhouse gas reduction policies in place or under development in a number of overseas locations. Throughout the developed world, there is a growing momentum towards introducing emissions trading schemes. The European Union Emissions Trading Scheme (EU ETS) is the largest trading scheme in place. In the USA, a number of initiatives are at various stages of development. This Appendix outlines the key features of the EU ETS, and two initiatives in the USA – the Regional Greenhouse Gas Initiative (RGGI) on the east coast and the Western Regional Climate Action Initiative (WRCAI) on the west coast. The latter includes participation by two Canadian provinces.

Carbon taxes are also used in some European countries.

A significant driver for these greenhouse gas reduction policies is the United Nations Framework Convention on Climate Change and, more specifically, the Kyoto Protocol which came about from it.

The Kyoto Protocol imposes legally binding emissions reductions targets on those developed countries which have ratified it. It therefore strongly influences the greenhouse gas policy environment in all developed countries, with the partial exception of the USA and Australia which have signed but not ratified the Kyoto Protocol. In addition, the Kyoto Protocol drives the incentives for emission abatement projects in most developing and transitional economies via the Clean Development Mechanism (CDM) and Joint Implementation Mechanism (JI).[1].

[1] http://unfccc.int/kyoto_protocol/mechanisms/items/1673.php

United Nations Framework Convention on Climate Change

The 1992 **United Nations Framework Convention on Climate Change** (the Convention) sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. The Convention's objective is to stabilise greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system, within a time-frame sufficient to allow ecosystems to adapt naturally, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner. [2]

The Convention acknowledges that the global nature of climate change requires the widest possible cooperation between nations in accordance with their common but differentiated responsibilities and respective capabilities and their social and economic conditions.[3]

The Convention has been ratified by 191 countries, including Australia. It commits Governments to:

- gather and share information on greenhouse gas emissions, national policies and best practices
- launch national strategies for addressing greenhouse gas emissions and adapting to expected impacts, including the provision of financial and technological support to developing countries
- co-operate in preparing for adaptation to the impacts of climate change.

Kyoto Protocol

To build upon the Convention, the 1997 **Kyoto Protocol** provided stronger and more detailed commitments for industrialised countries in order to more seriously tackle climate change. Also, the Protocol reaffirmed all parties' common but differentiated responsibilities to mitigate and facilitate adaptation to climate change. The Protocol came into force on 16 February 2005.[4]

[2] http://unfccc.int/essential_background/convention/background/items/1353.php

[3] http://unfccc.int/essential_background/convention/items/2627.php

[4] http://unfccc.int/kyoto_protocol/items/2830.php

Under the Protocol, the 38 Annex 1 Countries, which include developed nations as well as thirteen Eastern European economies in transition, are assigned emission targets (assigned amount) for the period 2008-2012. The targets are legally binding on countries that have ratified the Protocol.[5] Australia and the United States are the only Annex 1 countries not to have ratified the Protocol.

To reduce the compliance costs of meeting their targets, liable Annex 1 parties may use the following mechanisms to offset or meet their emission targets:

- create domestic offset credits called **removal units** (RMU) from carbon 'sinks' in the land use, land-use change and forestry sector
- use **emission reduction units** (ERUs) created from abatement activities from another Annex 1 party under the **'joint implementation'** mechanism (JI)
- use **certified emission reductions** (CERs) created from abatement projects in non-Annex I Parties under the **clean development mechanism** (CDM)
- transfer emissions from another Annex 1 party's assigned amount known as **assigned amount units** (AAUs)
- purchase CERs, ERUs or RMUs.

Under Article 17 of the Kyoto Protocol, the use of international offset credits must only be supplemental to domestic action which must constitute a significant element of a party's efforts in meeting their commitments. However the Kyoto Protocol provides no guidance as to how to quantify the limits of use of international offsets to meet the supplementarity requirement.

The European Union has quantified supplementarity to mean that a country can use CERs and ERUs to make up a maximum 50 per cent of the difference between its projected emissions in 2010 (or base year 1990, or 2004 emissions, whichever is the greater) and its average annual economy-wide Kyoto target. Recently, in Australia, the Prime Minister's Task Group on Emissions Trading considered the issue of the use of international offsets, but the PM's Task Group report does not specify whether there should be limits on their use.

Under the Kyoto Protocol, non-Annex 1 developing countries do not have any emissions targets. They can, however, create CERs under the CDM mechanism for sale to Annex 1 countries. As at mid-August, the price of issued CERs was about €16-17 per tonne of carbon dioxide equivalent ($tCO_{2\text{-}e}$), which is equivalent to around A$26.32-29.96.[6]

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[5] http://unfccc.int/kyoto_protocol/background/items/3145.php

[6] http://www.carbonpositive.net/viewarticle.aspx?articleID=137

European response to the Kyoto Protocol obligations

As noted above, all countries listed in Annex 1 of the Convention have ratified the Kyoto Protocol, with the exceptions of the USA and Australia. The Kyoto Protocol commits the European Union to reduce its greenhouse gas emissions by 8 per cent from the 1990 baseline by 2012[7]. The targets for individual EU member countries are listed in Table 5.2.1 below. In order to meet its emissions reduction commitments, the EU has decided to implement an emissions trading scheme, the EU ETS.

As noted above, the EU ETS is the world's largest emissions trading scheme. Phase 1 of the EU ETS runs for the period 2005-2007. In Phase 1, the EU ETS covers around 45 per cent of total greenhouse gas emissions from EU member countries, and most permits have been allocated for free. Member countries have been able to auction up to 5 per cent of the national allocation of permits.[8]. Permits in Phase 1 are known as European Union Allowances (EUAs).

The price of EUAs has fallen dramatically in the last 12 months, due to an over-allocation of free permits. The price of Phase 1 EUAs peaked at more than €30 (A$49.32) in April 2006. It then dropped significantly when emissions verification reports for 2005 revealed that EU countries had emitted less than their annual allocations.

As at 20 August 2007, the spot price of a Phase 1 December 2007 EUA was reportedly €0.11 (A$0.18).[9]

Phase 2 of the EU ETS runs for the period 2008-2012 and will coincide with the Kyoto Protocol's first commitment period. Final details about Phase 2 are still being negotiated within the EU. There are indications that the final allocation of EUAs to EU countries will result in a shortage of EUAs from 2008. This has resulted in a strong forward price in the trade of Phase 2 EUAs. At the close of trade on 17 August 2007, the forward price of the December 2008 EUA contract was €19.35 (A$31.81).[10]

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[7] The 8 percent reduction applies to the 15 countries who were EU members at the time the Protocol was signed. Since then, EU membership has increased to 27. The EU has decided to meet the 8 percent reduction by way of differentiated targets for individual countries within the original 15 members. Table A6.1 below lists the reduction targets for individual member countries.

[8] Prime Ministerial Task Group on Emissions Trading, Department of Prime Minister and Cabinet 2007, Report of the Task Group on Emissions Trading, pp 66-67

[9] Next Generation Energy Solutions, The Green Room, edition 116, 20 August 2007.
Currency conversion rate of 27/8/07:1A$ = €0.60; source www.xe.net. This rate is used for all Euro currency conversions in this chapter.

[10] Ibid.

The EU ETS is scheduled to undergo its first linkage to another scheme in the near future. Norway is currently operating an emissions trading scheme separate to the EU ETS. From 1 January 2008, the EU ETS and the Norwegian trading scheme will be linked. [11]

Additional targets adopted in Europe

In March 2007, the European Union agreed on greenhouse gas emission reduction targets additional those contained in the Protocol. The EU has agreed to achieve the following targets by 2020:

- reducing greenhouse gas emissions by 20 per cent on 1990 levels, with a commitment to a 30 per cent cut if the rest of the developed world does the same
- 20 per cent of electricity to be generated from renewable energy sources
- 10 per cent of its cars and trucks to run on biofuels.

Details about how these targets are to be achieved are still to be negotiated.

Table 5.2.1 lists the greenhouse gas emissions reductions targets for the 27 members of the European Union. The table shows firstly, the emissions levels (in million tonnes of $CO_{2\text{-}e}$) of the members in 1990 (the baseline year). It then shows the targets applicable to each country under the Kyoto Protocol for 2012 in terms of the percentage decrease in emissions from the 1990 base line. It also shows additional targets announced by some of the EU members.

The announced targets for the year 2050 are broadly consistent with those announced by a number of the State Governments in Australia. This is because the targets in Europe and in the Australian States have been developed in order to respond to the conclusions of the Intergovernmental Panel on Climate Change (IPCC). The IPCC's 2007 Assessment Report concludes that, if the global mean temperature increase is to be limited to less than 2.4 degrees Celsius, global CO_2-e emissions in 2050 must be reduced by 50 to 85 per cent of 2000 emissions. These scenarios include global CO_2-e emissions peaking by 2015.

[11] Op cit, xvii, p 67.

Table 5.2.1: European Union Greenhouse Gas Emission Reduction Targets

Emissions Reduction Targets – European Union Members				
Country	**1990 Baseline (Mt)**	**Kyoto Target 2012 (%)**	**2020 Target (%)**	**Other Announced Targets (%)**
EU – 15 member states as at signing of Kyoto Protocol		- 8 (EU to decide how the target will be redistributed among the 15 states)	- 20 (1990 baseline) (for whole EU)	- 30 (if rest of developed world agrees to also do so)
Austria	78.9	-13		
Belgium	146.9	-7.5		
Denmark	69.3	-21		-50 by 2030[12] (1990 baseline)
Finland	71.1	0		
France	567.1	0		-75 by 2050[13] (1990 baseline)
Germany	1,230.0	-21	-40[14] (1990 baseline)	
Greece	111.1	25		
Ireland	55.8	13		
Italy	518.9	-6.5		
Luxembourg	12.7	-28		
Netherlands	214.3	-6	-30[15] (1990 baseline)	
Portugal	60.0	27		
Spain	289.4	15		

[12] http://www.inforse.dk/europe/word_docs/s_gbo_dk.doc

[13] http://www.industrie.gouv.fr/energie/anglais/politique-energetique.htm

[14] http://www.euractiv.com/en//germany-plans-cut-climate-emissions-40/article-163424

[15] http://www.bellona.org/articles/dutch_enviropolicy

Table 5.2.1: European Union Greenhouse Gas Emission Reduction Targets (cont)

Emissions Reduction Targets – European Union Members				
Country	**1990 Baseline (Mt)**	**Kyoto Target 2012 (%)**	**2020 Target (%)**	**Other Announced Targets (%)**
Sweden	72.5	4	-30[16] (1990 baseline)	
United Kingdom	767.9	-12.5	-26 to -32[17] (1990 baseline)	-60 by 2050 (1990 baseline)
New members May 2004				
Cyprus	6.0	N/A		
Czech Republic	196.3	-8		
Estonia	42.6	-8		
Hungary	122.2	-6		
Latvia	25.9	-8		
Lithuania	50.9	-8		
Malta	2.2	N/A		
Poland	565.3	-6		
Slovakia	73.2	-8		
Slovenia	20.2	-8		
New members Jan 2007				
Bulgaria	88.4[18]	- 8		
Romania	212.9[19]	- 8		

North American initiatives to reduce greenhouse gas emissions

Regional Greenhouse Gas Initiative (RGGI)

The RGGI is a co-operative effort by 10 north-eastern and Mid-Atlantic States in the United States of America to reduce carbon dioxide emissions. Its central element is a multi-state cap-and-trade program with a market-based emissions trading system. The proposed program will require electricity generators in participating states to reduce carbon dioxide emissions.

It is reported that the program will begin by capping emissions at current levels in 2009, and then reducing emissions 10 per cent by 2019.[20]

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[16] http://www.greencarcongress.com/2007/05/sweden_targets_.html

[17] Department for Environment Food and Rural Affairs (UK), 2007, Climate Change Strategic Framework.

[18] Bulgarian Government's 2006 Annex I Party GHG Inventory Submission

[19] Romanian Government's 2006 Annex I Party GHG Inventory Submission

[20] For more information see http://www.rggi.org/

Western Regional Climate Action Initiative (WRCAI)

As at 13 June 2007, the Western Regional Climate Action Initiative involves six western states in the USA (Arizona, California, New Mexico, Oregon, Utah and Washington) as well as two Canadian provinces (British Columbia and Manitoba).

The Agreement initially signed by the Governors of Arizona, California, New Mexico, Oregon and Washington on 26 February 2007 committed to:

- setting an overall regional goal, within six months of the effective date of this initiative, to reduce emissions from these states collectively, consistent with state-by-state goals
- developing, within eighteen months of the effective date of this agreement, a design for a regional market-based multi-sector mechanism, such as a load-based cap and trade program, to achieve the regional greenhouse gas reduction goal
- participating in a multi-state greenhouse gas registry to enable tracking, management, and crediting for entities that reduce greenhouse gas emissions, consistent with state reporting mechanisms and requirements.

California

In addition to its membership of WRCAI, California has undertaken a number of greenhouse gas reduction initiatives on its own. On 1 June 2007, California released a draft report on a possible state-wide cap and trade scheme for the consideration of the Californian Air Resources Board to decide whether or not emissions trading should form part of the State's strategy to meet its legislated greenhouse gas emission targets of reducing emissions to:[21]

- 2000 levels by 2010
- 1990 levels by 2020
- 80 per cent below 1990 levels by 2050.

California has also made it mandatory through its Renewable Portfolio Standard that 20 per cent of electricity supplied in the State is to be from renewable sources by 2010, with the renewable energy target increasing to 33 per cent by 2020.

[21] For more information, see: http://www.climatechange.ca.gov

Canada

In April 2007, the Canadian Government announced it aimed to reduce the country's greenhouse gas emissions by 20 per cent by 2020 on 2006 levels.

The Canadian Government has also announced that a domestic baseline and credit scheme will be introduced to allow regulated firms to buy and sell emission credits among themselves. The trading scheme would allow regulated firms to invest in verified emission reductions outside the regulated system to create domestic offsets and also allow firms to access certain qualifying credits from the Kyoto Protocol's Clean Development Mechanism to meet their targets.[22]

New Zealand

On 8 May 2007, the Minister for Climate Change indicated that in the next three months the New Zealand Government will make important decisions on New Zealand's move towards a greenhouse gas emissions trading regime. [23] Although the Government has not set any emissions reduction targets beyond the end of the Kyoto Protocol in 2012, the opposition National Party has announced its policy for a 50 per cent reduction on 1990 levels by 2050.

Negotiating future international emissions reductions

International emissions reduction targets and carbon trading markets beyond the expiry of the Kyoto Protocol in 2012 have not yet been decided. There are a number of current and proposed forums and mechanisms which may lead towards a global agreement on mitigating climate change beyond the end of the Kyoto Protocol in 2012.

The following section outlines major recent developments at the inter-governmental level. Important factors in setting the international carbon constraint and for influencing Australia's potential participation in it include the process for setting it, the form of an agreement and the size of the emissions constraint or target.

Post Kyoto

Parties to the Kyoto Protocol meet under the Convention to discuss further global action on climate change beyond 2012. Linked to this process, but currently operating in parallel, is the *Dialogue on long-term cooperative action to address climate change by enhancing implementation of the Convention*, in which Australia and other non-parties to the Kyoto Protocol can contribute[24].

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[22] For more information see: http://www.ec.gc.ca

[23] http://www.beehive.govt.nz/ViewDocument.aspx?DocumentID=29222

[24] For more information, see UNFCCC, 2006, Report of the Conference of the Parties on its twelfth session, held in Nairobi, 6 to 17 November 2006 available from http://unfccc.int.

G8 Summit

In June 2007, the leaders of the eight leading industrialised nations[25] agreed that "the UN climate process is the appropriate forum for negotiating future global action on climate change" and committed to achieving a comprehensive post 2012-agreement under the Convention by 2009 and including all major emitters. The G8 leaders stressed their continued support for the Convention principle of common but differentiated responsibilities and respective capabilities. They acknowledged "the continuing leadership role that developed economies have to play in any future climate change efforts to reduce global emissions" and also recognised that the efforts of developed economies will not be sufficient.

The leaders agreed that the United States' proposal for a separate process "will support the UN climate process". The proposal involves a meeting of major greenhouse gas emitting countries, including Brazil, China, India, Mexico and South Africa, later in 2007[26].

APEC and AP6

In the Asia-Pacific region, the Australian Government is exploring greater regional cooperation on climate change through the Asia-Pacific Economic Co-operation (APEC) Forum, the Asia-Pacific Partnership on Clean Development and Climate (AP6) and a number of bilateral agreements. These agreements focus primarily on international cooperation on technology development and transfer. No decisions have been taken to establish greenhouse gas emissions reduction targets, carbon trading markets or carbon prices.[27]

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[25] The G8 member countries are the USA, Japan, Germany, the UK, France, Italy, Canada and Russia.

[26] For more information see G8 Summit, 2007, Growth and Responsibility in the World Economy, Summit Declaration (7 June 2007).

[27] For more information, see http://www.dfat.gov.au

A6.1 Estimating the Cost of Publicly Funding the New Generation Pathway

In order to analyse the potential impact on the State's fiscal position of publicly funding the State's generation needs, a generation pathway model has been developed after considering:

- estimates of the State's potential generation needs. This included the most recent NEMMCO estimates;
- the latest cost estimates for future generation capacity, including those prepared by ACIL Tasman; and
- potential generation sites identified by the energy SOCs as being suitable for investment.

Estimating emerging generation needs

Chapter 2 sets out a range of dates when new generation investment may need to commence. It argues that although it may be prudent for the Government to use an earlier rather later date for its analysis, the exact timing and type of investment will be determined by the investment market after substantial modelling and analysis. But to analyse the financial impact on the State of funding this investment, a model generation pathway has to be used.

One independent generation pathway is modelled in the *Simulated Generation Expansion for NSW* as contained in the 2006 NEMMCO *Statement of Opportunities*[1] (SOO). This simulation provides a pathway that is transparent, publicly available and consistent with the prudent approach adopted in Chapter 2 on the State's emerging generation needs.

NEMMCO, as part of the SOO process, publishes a generation investment pathway for each region of the NEM to meet projected shortfalls in existing and committed supply in a cost-effective way.

[1] NEMMCO, *Statement of Opportunities for the National Electricity Market,* October 2006

This part of the SOO is focused on assessing the viability of justifying inter-regional transmission upgrades. It does not necessarily result in the optimum generation development within New South Wales. Using different assumptions, some commentators may correctly argue that the generation development indicated for New South Wales in the 2006 SOO is a higher than likely view of the State's generation needs.

This simulation reflects a commercial approach to making a decision to invest in a new power station (i.e. the capital and operating costs of different types of generation and the return required to make the investment commercially attractive). While illustrative of a potential pathway, neither NEMMCO nor the Inquiry would predict that this is the only or indeed the most certain way the electricity market will evolve. Rather, this is a robust scenario that:

- assumes future supply short falls are met by investment in new generation capacity with no additional transmission system augmentation[2]
- attempts to reflect the commercial considerations of a potential new generation investor, however does not capture every consideration (i.e. investor views on political and policy environments in the different regions of the NEM including fuel sources for new generation given the current uncertainty around the cost of carbon)
- may excessively reflect restrictions on the availability of gas for power generation in New South Wales.

The simulated generation expansion for New South Wales as determined in the 2006 SOO is set out in Table 6.1.1.

Table 6.1.1: NEMMCO Simulated Generation Expansion Pathway

Plant Type	2007-08 (MW)	2008-09 (MW)	2009-10 (MW)	2010-11 (MW)	2011-12 (MW)	2012-13 (MW)	2013-14 (MW)	2014-15 (MW)	2015-16 (MW)
COAL						500	500	500	500
CCGT				385	385				
OCGT			450	150	150				
Total			**450**	**535**	**535**	**500**	**500**	**500**	**500**

Source: NEMMCO, Statement of Opportunities 2006, Table H8, Appendix H.

[2] It should also be noted that while transmission interconnection upgrades are modelled by NEMMCO in the SOO, the augmentations modelled make little difference to the baseload generation requirements in New South Wales.

Other pathways are possible. For instance, market participants may consider that gas is more prospective and substitute CCGT for coal. Slower growth in demand, greater energy efficiency or higher investment in renewables may push out the timing for investment. Alternatively, a significant major project or different assumption about interstate fuel prices may bring forward the timing of investment.

Each of these issues would affect the timing of the fiscal impact on the State from funding the generation pathway. In this sense, the fiscal costs in Chapter 6 are illustrative of the fiscal pressures that will emerge with publicly funding the generation pathway.

Estimating generation costs

To provide a consistent and transparent approach, the Inquiry used the new entrant generation costs provided by ACIL Tasman to NEMMCO for the purpose of modelling the simulated generation expansion.[3]

These costs provide estimated short and long run marginal cost of potential coal and gas-fired generators in 17 zones identified in the NEM (reflecting geographically driven costs such as fuel cost and availability, transmission capability and cost; and availability of water and other infrastructure).[4]

The costs used from the ACIL Tasman report by the Inquiry included the estimated project capital cost ($/kW) for:[5]

- new OCGT power stations built in the years to 2019-20
- new CCGT power stations built in the years to 2019-20
- new build supercritical black coal-fired power stations built in the years to 2019-20.

[3] These costs are updated as at March 2007

[4] For further information on both the simulated generation expansion and new generation costs, refer to NEMMCO, *Statement of Opportunities*, 2006 and ACIL Tasman, *Fuel resource - new entry and generation costs in the NEM*, *Report 2 – Data and Documentation*, 27 March 2007

[5] Ibid, Tables 81, 77 and 78, p.116, p.111, p.114 respectively.

Table 6.1.2: Estimated project capital cost for a new build OCGT power station, 2007-08 to 2025-26

Year	Nominal $/kW	Real (2007-08) $/kW
2007-08	720	720
2008-09	734	716
2009-10	749	713
2010-11	764	710
2011-12	779	706
2012-13	795	703
2013-14	811	699
2014-15	827	696
2015-16	844	692
2016-17	860	689
2017-18	878	686
2018-19	895	682
2019-20	913	679
2020-21	931	676
2021-22	950	672
2022-23	969	669
2023-24	988	666
2024-25	1,008	663
2025-26	1,028	659

Source: ACIL Tasman, Fuel Sources, new entry and generation costs in the NEM, Report 2, Table 81.

Table 6.1.3: Estimated project capital cost for a new build CCGT power station, 2007-08 to 2025-26

Year	Nominal $/kW	Real (2007-08) $/kW
2007-08	1,050	1,050
2008-09	1,071	1,045
2009-10	1,092	1,040
2010-11	1,114	1,035
2011-12	1,137	1,030
2012-13	1,159	1,025
2013-14	1,182	1,020
2014-15	1,206	1,015
2015-16	1,230	1,010
2016-17	1,255	1,005
2017-18	1,280	1,000
2018-19	1,306	995
2019-20	1,332	990
2020-21	1,358	985
2021-22	1,385	981
2022-23	1,413	976
2023-24	1,441	971
2024-25	1,470	966
2025-26	1,500	962

Source: ACIL Tasman, Fuel Sources, new entry and generation costs in the NEM, Report 2, Table 77.

Table 6.1.4: Estimated project capital cost for a new build supercritical black coal-fired power station 2007-08 to 2025-26

Year	Nominal $/kW	Real (2007-08) $/kW
2007-08	1,700	1,700
2008-09	1,734	1,692
2009-10	1,769	1,683
2010-11	1,804	1,675
2011-12	1,840	1,667
2012-13	1,877	1,659
2013-14	1,914	1,651
2014-15	1,953	1,643
2015-16	1,992	1,635
2016-17	2,032	1,627
2017-18	2,072	1,619
2018-19	2,114	1,611
2019-20	2,156	1,603
2020-21	2,199	1,595
2021-22	2,243	1,588
2022-23	2,288	1,580
2023-24	2,334	1,572
2024-25	2,380	1,564
2025-26	2,428	1,557

Source: ACIL Tasman, Fuel Sources, new entry and generation costs in the NEM, Report 2, Table 78.

Estimating the fiscal impact of publicly funding the new generation pathway

Both the energy State Owned Corporations (SOC) and the private sector are currently investigating sites on which new generation capacity can be built. These are both peak/intermediate sites and baseload/intermediate sites to determine their technical and environmental feasibility.

By overlaying the NEMMCO simulated generation expansion pathway for New South Wales, and the current sites for new generation capacity, the Inquiry was able to derive a possible fiscal scenario where the State's emerging generation needs are publicly funded to the maximum extent.

Under this scenario, the NEMMCO forecast supply shortfalls in New South Wales, over the period to 2015-16, are met by the energy SOCs through the construction and commissioning of two new open-cycle gas-fired power stations, two new closed-cycle gas-fired power stations and two new coal-fired power stations. Using the ACIL Tasman cost estimations, the cost of this investment path to New South Wales is approximately $7 billion to $8 billion.

The Inquiry, notes that the generation pathway, derived from the NEMMCO SOO, is based on a number of assumptions around fuel price and availability, and that as discussed in Chapter 2 some other models forecast different investment timing. The capital cost actually incurred could therefore be lower. However, against this is the tightening domestic market for skilled labour and international market for materials and parts, which the Inquiry considers may increase the cost of the investment pathway. Given the current infrastructure investment cycle, this tightening market is anticipated to continue into the foreseeable future and impact on at least the next tranche of generation investment.

Estimating the impact of other SOC investments

In assessing the cost to Government from publicly funding the State's emerging generation needs, the Inquiry also recognises that such an outcome will likely expose the Government to addition funding requirements associated with the implied continued ownership of State's electricity businesses. Potentially, the major expenses are the cost incurred to retrofit coal-fired power stations with emerging carbon reduction technologies, and placing retail businesses on equal footing with competitors.

Retrofitting the existing coal-fired power stations with carbon capture technology

If the NSW Government continues to retain ownership of its generation assets, then significant expenditure may be required in retrofitting at least one major existing baseload coal plant with carbon capture and storage (CCS) technology over the foreseeable future.

This technology would give the existing power stations the capability of capturing their carbon dioxide emissions, thus putting them more in line with new plant, at a time when reducing carbon emissions will be of utmost importance and an emissions trading scheme will be in place. Such expenditure may be necessary from 2020, if New South Wales is to meet its 2025 emissions target, as discussed in Chapter 5.

It is difficult to estimate the cost of retrofitting an existing plant with CCS technology, as it is an immature technology that is not currently in operation on a commercial scale. However, in order to gain an indicative cost, the Inquiry has compared the $/kW construction costs of a new ultra-supercritical pulverised coal plant with carbon capture technology against one that does not and derived an indicative capital expenditure figure of $3 billion to $4 billion.[6].

This cost reflects the higher capital costs from incorporating carbon capture and the reduction in thermal efficiency and output of the plant given the very high electricity needs to run the carbon capture plant. The cost does not include any additional cost likely to be incurred with transporting and sequesting the captured carbon.

Future retail investment

The State-owned retail businesses are 'pure' retailers, in that they do not have interests in generation and upstream gas reserves for which to manage their risks and optimise their returns. This 'pure' retail business model was abandoned by their competitors some time ago, and therefore the State-owned retailers are at a competitive disadvantage vis-à-vis their competitors. By continuing as 'pure' retailers their value will inevitably decline.

If the State-owned retailers are to become more competitive by adopting a similar business model to their competitors, then significant capital expenditure will be required. This significant capital investment will comprise of:

- development of an upstream gas position ($1 billion to $2 billion)
- development of a generation position (with an optimal position requiring an additional $1 billion investment in addition to the gas-fired peaking plants included in the generation pathway).

Therefore, capital expenditure in the order of $2 billion to $3 billion is required.

It should be noted that this will not guarantee that the State-owned retailers will be on equal footing with their competitors. The State-owned retailers do not possess the scale of their main competitors, and competitive positions take several years to establish. Furthermore, by competing in upstream gas activities, the Government will be assuming additional risk exposure.

[6] Expert Report 1, p 14 and p.56.

Estimating the fiscal impact of publicly funding the total investment pathway

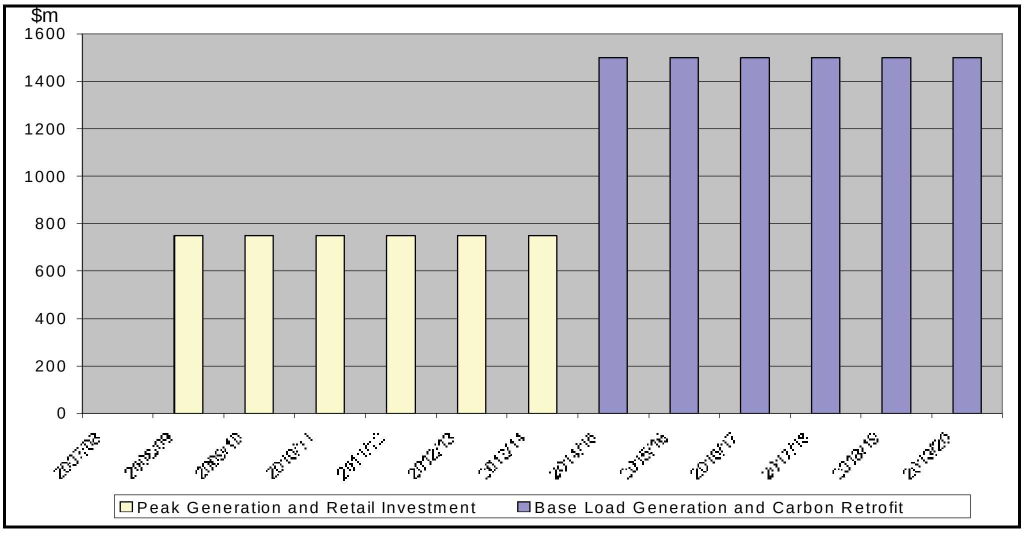
Therefore, if the Government retains ownership of its retail and generation assets, it will, in the Inquiry's opinion, be subjected to significant capital costs over the next decade, potentially placing the State under significant fiscal pressure.

The estimated total cost of publicly funding the investment pathway is in the range of $12 billion to $15 billion, comprising:-

- new generation investment in the range of $7 billion to $8 billion, required to meet the State's emerging generation capacity needs
- additional expenditure of around $3 billion to $4 billion to retrofit coal-fired power stations with emerging carbon reduction technologies
- additional investment in interstate generation and gas equity positions in the range of $2 billion to $3 billion, required to move the State-owned retailers onto a more equal footing with their private sector competitors.

The timing of the total investment pathway will depend on market circumstances. However, it is likely that new investment for peaking plant and further investment in retail activities of between $4 billion and $5 billion will be required over the first half of the projection period. New investment for base load generation and the retrofit of existing plant of between $8 billion and $10 billion will be required over the second half of the projection period. For modelling purposes, the Inquiry has taken the mid-point of the respective cost estimates and smoothed the required investment over these two periods, shown in Figure 6.1.1.

Figure 6.1.1: Cost of NSW Emerging Generation Needs[7]



[7] Based on the mid-point of estimated cost ranges

A6.2 Importance of maintaining the State's AAA credit rating

The primary role of the NSW Government is to provide public services. The State's fiscal strategy is to have a strong balance sheet to ensure that this role can be met in the face of unanticipated events. A strong balance sheet provides the State with the capacity to absorb the effects of short term revenue fluctuations and to gradually adjust to longer term fiscal pressures. Having the highest credit rating provides a sure sign that the State's balance sheet is strong and sustainable and that service delivery growth can be maintained.

Recasting this in the negative, the fiscal strategy of a strong triple-A rated balance sheet is designed so that the Government can avoid having to reduce services or increase taxes in response to downturns in the revenue cycle. This prevents having to reduce health, education, public transport, community and policing services merely because there is a downturn in Sydney property market transactions.

New South Wales has had the highest credit rating from both major credit rating agencies, Moody's and Standard & Poor's, since ratings were first introduced for the State in 1987. Having the highest credit rating does secure the lowest possible borrowing costs for the State, thereby freeing up revenues for service delivery rather than interest costs.

However, the importance of maintaining a AAA credit rating goes beyond the financial implications from securing the lowest borrowing costs. Confidence in the financial health of New South Wales would deteriorate as a result of a credit rating downgrade. This would negatively impact on business confidence, reducing the attractiveness of the State as a destination for investment, with resultant effects on the economy. This indirect cost far outweighs the initial budgetary cost, as the Victorian experience of the early 1990s demonstrated.

The announcement of a rating downgrade, or even a negative review (or *Credit Watch*) would degrade a State's credibility in international markets where debt instruments have been popular. It would also have an impact on a State's capacity to raise capital and the price it has to pay for that capital.

Based on other State's experience, once downgraded it takes considerable time, fiscal stringency and a sustained demonstration of achieving robust fiscal targets to regain the highest credit rating. This is illustrated below with reference to Victoria during the 1990's.

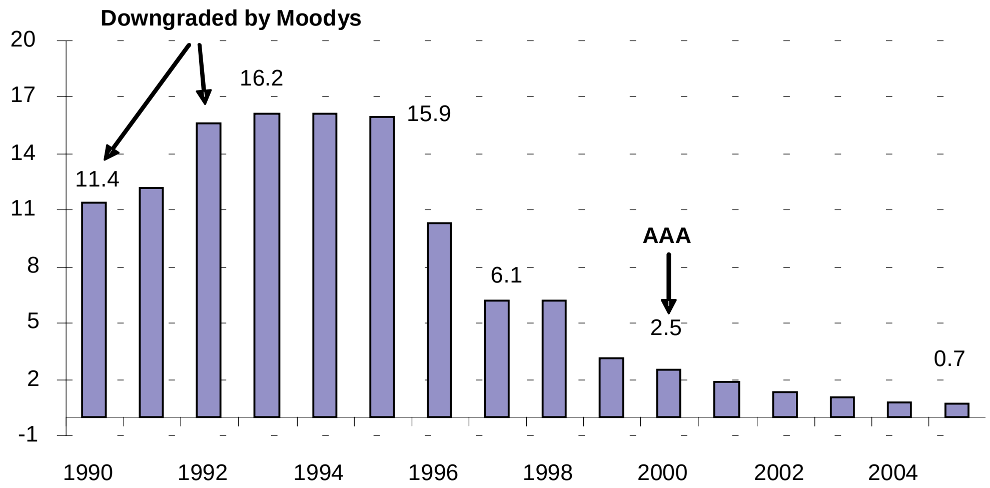
Victorian credit rating experience

In the late 1980s/early 1990s, Victoria was recording a general government operating deficit prior to the onset of recession.

When the recession took hold, the deficit increased sharply and General Government net debt increased from less than 12 per cent of GSP in 1990 to 16 per cent of GSP in 1992, and to around 30 percent of GSP for the non-financial public sector. This was higher than all states except South Australia where general government sector net debt peaked at 24 per cent of GSP and non financial public sector net debt peaked at 35 per cent of GSP.

As a result of the sharp acceleration in debt levels, a loss of business confidence and doubts about the State Government's ability to manage its finances, Moody's downgraded Victoria's credit rating in June 1990 and again in October 1992. A change in Government saw a shift in financial policy, including a commitment to reduce State debt, improve business confidence and restore the State's AAA credit rating. The Government had to increase taxes and reduce growth in expenditure. The Government also applied the proceeds of assets sales to debt retirement. In response to Victoria's improving budget position in the mid-1990s, a recovering economy and restored business confidence, Moody's increased the State's credit rating incrementally from mid-1994, but a AAA credit rating was not restored until February 2000, almost 10 years after the initial downgrade.

Victoria's General Government net debt (% GSP)



A6.3 Public-private partnerships

Similar to other areas involving the provision of infrastructure, an alternative to either stand alone public or private sector funding of new generation is the public-private partnership model.

There are a range of potential public-private partnership transactions from which the energy SOCs could develop new baseload generation investment with private financing. The two most notable options for baseload generation projects are either a form of Joint Venture or a Power Purchase Agreement.

The underlying attractions of potential public-private partnership transactions for Government are that they allow the private sector to:

- contribute project equity that reduces or replaces the need for public sector project equity; and
- manage risks (i.e. construction, procurement, financing) that are broadly viewed as more appropriate to be managed by the private sector.

However, despite these attractions with regard to the provision of new baseload generation power stations in New South Wales, there are likely to be some associated adverse impacts on the State.

These impacts are considered below for power purchase agreements (PPA) and joint venture arrangements.

Power Purchase Agreements

Risk Exposure for the State:

- an inherent risk of any public-private partnership is the potential for Government entering into a contract that is unduly more advantageous to the private sector than the public sector
- PPAs will leave - to varying extents depending on the conditions of the specific PPA - the Government exposed to the wholesale energy price. This risk is the most significant risk in any new generation project and the Government's continued exposure will be considered by the ratings agencies when determining the State's credit rating.

Value Impacts for the State

- The financial burden of a PPA for the State takes the form of a stream of payments over the life of the agreement, which replaces the upfront capital cost of a conventionally financed project. In accounting terms, a PPA to underwrite a new power station receives equivalent treatment to that of financing the construction of a new power station. The fixed payments under a PPA are directly analogous to the interest and depreciation costs associated with financing and owning the power station.

Joint Ventures

In assessing the merits of public-private joint ventures to construct a baseload power station the Inquiry has considered a number of variants including a 'Share of portfolio', 'Independently-traded joint venture' and 'unincorporated joint venture'. While each model has its relative advantages and disadvantages all were found to have the following drawbacks:

Risk Exposure for the State:

- an inherent risk of any joint venture is the potential for Government entering into a contract that is unduly more advantageous to the private sector than the public sector
- Government remains exposed to the risky and competitive sections of the electricity market (through generation and retail ownership) which will continue to be considered by the ratings agencies when determining the State's credit rating.

Value Impacts for the State:

- Joint ventures dilute control of Government ownership creating inherently unsustainable public/private ownership arrangements. The management of these situations normally involves complex corporate governance arrangements that may result in loss of shareholder value.

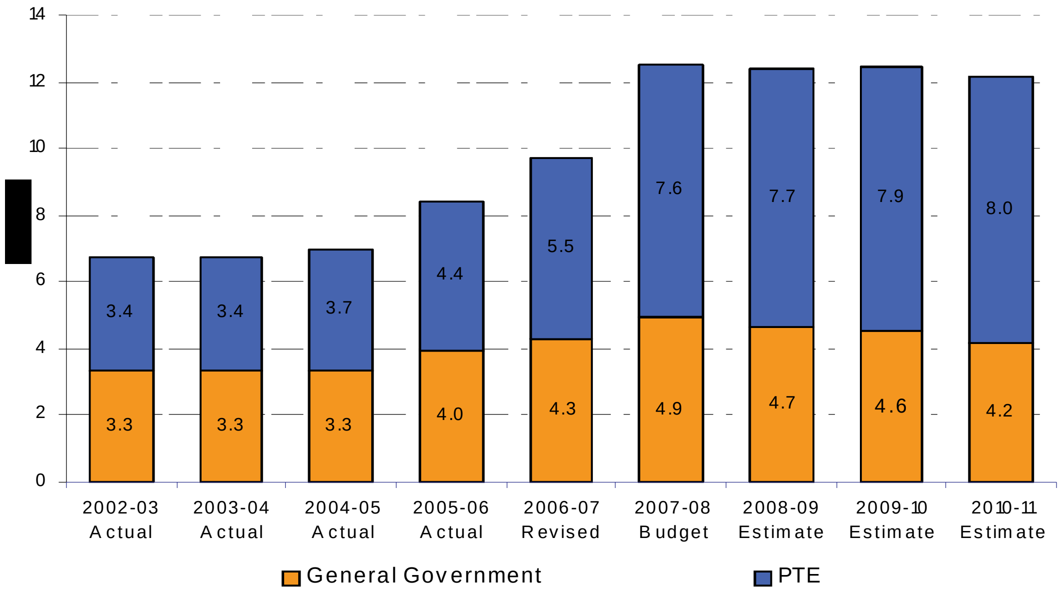
Further, and perhaps equally important, as considered in the following chapter, no public-private partnership will realise any significant proceeds that would be available to the Government to strengthen the State's fiscal position and credit rating.

A6.4 The State's current and committed capital program

The Government has a ten year capital expenditure plan set out in the State Infrastructure Strategy (SIS). The 2007-08 NSW State Budget sets out the increase in capital spend associated with the years 2007-08 to 2010-11.

Over the four years to 30 June 2011 (2007-08 to 2010-11), the State's capital expenditure is expected to total $49.6 billion. This is an increase of $17.8 billion or 55.8 per cent on the $31.8 billion expenditure over the four previous years to 30 June 2007 (2003-04 to 2006-07). As shown in the figure below, the increase is particularly pronounced in the Public Trading Enterprise (PTE) sector.

Figure 6.4: State Capital Expenditure



The $49.6 billion capital spending over the forward estimates includes:

- implementation of the 2006 Metropolitan Water Plan to secure Sydney's water supply into the future by:
  - maximising water recycling so by 2015 the amount of wastewater recycled will grow fourfold to 70 billion litres a year for use in homes, irrigating, agriculture, industry and to mimic natural river flows downstream of dams
  - increasing supply by accessing deep water in our dams
  - encouraging water saving by households, businesses, councils and government
  - having drought proof solutions at the ready, such as groundwater and desalination.
- improving the State's electricity transmission and distribution network to meet growth, particularly in peak demand across the State, changing demographics and usage patterns, and enhancing network reliability and security
- major upgrades to highways and regional roads as well as implementation of the 2006 Urban Transport Statement to meet Sydney's present and future transport needs by addressing capacity, reliability and congestion:
  - extending the Clearways Program to improve capacity and reliability on CityRail's Sydney suburban network
  - acceleration of the proposed Metropolitan Rail Expansion Program to extend the rail network to the western growth centres of Sydney
  - improvements to the metropolitan road network by fixing traffic "pinch points" and upgrading Victoria Road
  - improving bus travel times and reliability by 80 individual bus priority works.
- health sector capital expenditure responding to ongoing changes to service delivery needs, population changes, technological developments and the need to renew aging infrastructure including major hospital upgrades and redevelopments, improved diagnostic capability, upgrades to ambulance infrastructure and improved mental health and preventative care facilities
- investment in the education sector to support learning and the development of a skilled workforce by building new schools in growth areas, upgrading existing TAFE and school facilities including the addition of trade schools, and increasing the use of information technology in the classroom
- implementation of a State-wide long term plan for reconfiguration of public housing assets to better match client needs.

Significant increases in infrastructure spending in both the general government and non-commercial PTE sectors are expected to extend beyond the forward estimates period, driven by several factors - including population growth, ageing and redistribution; advances in technology; and the need for infrastructure renewal in several sectors. Higher than expected capital cost inflation could add further pressure on the State's finances, through higher debt associated with delivery of projects.

Report to the Owen Inquiry into Electricity Supply in NSW

NSW Power Generation and CO_2 Emissions Reduction Technology Options

Reference: 29032

27 August 2007

Connell Wagner

NSW Power Generation and CO_2 Emissions Reduction Technology Options

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Contents

1. Introduction

This report describes the findings of a review conducted by Connell Wagner into the characteristics and availability of electricity generation technologies suitable for base load electricity generating plant in New South Wales and where applicable the options for reducing their associated carbon dioxide emission.

1.1 Background

In May 2007 the NSW Government announced that Professor Anthony Owen would be leading an inquiry into the need and timing of base load electricity generation in NSW. As part of this study Connell Wagner was engaged to assist with the provision of information on currently available and next generation electricity generation technologies and potential carbon dioxide emission reduction technologies.

The objective of this study is to provide input to the Owen Inquiry into electricity supply in NSW. Specifically, this study identifies the greenhouse gas emissions, reliability and performance characteristics of prospective technologies and the existing NSW generating plant technologies and how the technologies could fit into the NSW operating environment.

1.2 Scope

The review comprises three discrete components:

1.2.1 Identification of Prospective Technologies

This aspect of the review included:

– Identification of currently available and next generation electricity production technologies.

– Identification of potential carbon dioxide emission reduction technologies.

– A description of each technology and provision of details on its performance characteristics, environmental performance including greenhouse and water consumption issues, and construction and operating cost information. An assessment was made of the technical capacity factor and/or energy output limits and the technological maturity for base load application in NSW and whether it could be expected to meet the timeframe for availability in relation to the NSW base load growth.

– An assessment of the suitability of each technology for providing base load electricity production to NSW.

1.2.2 Applicability of Technologies to NSW Operating Environment

This component of the review addressed how the new technologies would fit in to the NSW operating environment and how they would contribute to meeting the load duration curve.

1.2.3 Existing Base and Intermediate Load Generation Plant

A review was conducted of the characteristics of each existing NSW base load and intermediate generation plant (including snowy hydro plants and the sugar mills). This review addressed:

– Greenhouse gas emission rates;

– Expected forced outage rates;

– Expected planned outage rates;

– Technical capacity factor and/or energy output limits ;

– Major refurbishment requirements and timeframes

– The impact of major refurbishment on planned outage rates

Data provided by the four main NSW electricity generators was collated and analysed.

1.3 Methodology

1.3.1 Identification of Prospective Generation and CO_2 Capture and Disposal Technologies

The information gathered for this component of the study was obtained from a variety of sources. These sources included Connell Wagner's internal database, extensive library and Internet search of global power generation projects and carbon capture technologies and public domain work conducted in Australia by Cooperative Research Centres, research organisations, the Energy Supply Association Australia (ESAA) and the National Electricity Market Management Company (NEMMCO).

A short list was made, comprising the following base load generation technology options, which include both renewable and non-renewable primary energy sources:

- Pulverised coal fired with ultra-supercritical steam conditions
- Integrated coal gasification combined cycle
- Ultra clean coal fired gas turbine combined cycle
- Geothermal (hot rocks)
- Nuclear
- Gas turbine (open and combined cycle)
- Solar thermal
- Biomass (wood, agricultural waste)
- Wind
- Hydro

Where steam condensation was required, the option of dry and wet cooling systems was addressed.

The review of prospective carbon emission reduction technologies targeted CO_2 capture technologies and disposal options. The prospective capture technologies that were investigated included:

- Post -combustion gas scrubbing to remove CO_2 from flue gas
- Oxy-fuel combustion with flue gas recycle
- Pre-combustion separation of CO_2 from fuel gas

The disposal technologies that were considered included:

- Geological storage
- Deep ocean storage
- Stable carbonate storage

Due to the novelty of both the advanced coal technologies and the carbon dioxide capture & storage technologies, the peer review of these sections of the report was obtained from two eminent experts in this field. Dr Lila Gurba from the University of New South Wales (who was until recently a Research Manager for the CRC for Coal in Sustainable Development) reviewed and provided input to the sections on advanced power systems from fossil fuels including CO_2 capture and storage technologies. Dr Kelly Thambimuthu, the CEO of the Queensland Centre for Low Emission Technology, conducted a final high level review of the overall report.

1.3.2 Applicability of Technologies to the NSW Operating Environment and Load Profile

The data obtained on the prospective generation technologies was analysed with respect to the expected environmental, performance and financial requirements of a base load plant for construction in New South Wales.

1.3.3 Review of Existing Base and Intermediate Load Generation Plant

A questionnaire was sent to the four major generators in NSW (Macquarie Generation, Delta Electricity, Eraring Energy and Snowy Hydro) on commencement of the project covering the required greenhouse gas coefficients, outage rates, capacity factors and refurbishment programs. This was followed by a visit from a Connell Wagner team member to discuss the data with the utilities. The responses were critically appraised using Connell Wagner's own knowledge of the plant .

1.4 Terms of Reference

1.4.1 Base load Generation

This report relates to the capability of electricity generating technologies to supply "Base load" capacity for the State. However, the meaning of the term, as used in this report, requires some definition, as the concept tends to have shades of meaning. For the purpose of the report the following provides a conceptual framework.

There are times of the day and the year when there is a high electricity demand in NSW, most likely very cold or hot days and there are other times when the demand may be relatively lower. Unlike many commodities, large-scale electricity cannot be stored, necessitating generation to match demand or load.

This can be shown graphically in terms of a load duration curve, shown in Figure 1.1. This curve plots the load against the percentage of time. For example, from the curve it can be seen that a load of 7000 MW and higher exists 80% of the time. On the other hand, loads above 10,000 MW only occur for 10% or less of the time.

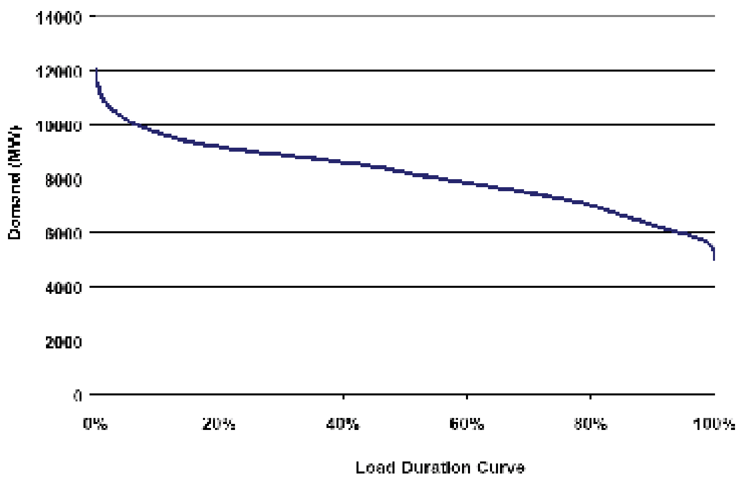

Figure 1.1 Example of Typical Load Duration Curve

Typically a level of load that existed around 50% or more of the time would be considered in the range of base load. In order to supply the base load a number of generating plants are required. Such generating plants would be expected to have the following attributes:

Reasonable Cost: A plant to supply the base load needs to consider the long term affordability of the significant amount of electricity that it produces. The trade off between capital investment and fuel cost needs to be considered.

Reliability: Base load must be supplied virtually all of the time. Although no plant operates all of the time, the plant that is supplying the base load must have high reliability. Consequently in the selection of plant for this duty, the history of performance of a technology is essential.

Environmental Impacts: The quantity of electricity necessary to supply the base load is significant, and depending on the source of energy and the technology, can have significant environmental impacts both locally and globally. The environmental impacts of a plant supplying the base load need to be minimised and balanced carefully with the cost.

Flexibility: The overall electricity supply systems comprises many types of generating units including, photovoltaic, wind units, biomass thermal units, open cycle gas turbines, combined cycle plant, coal fired steam turbine plant and hydro. All of these plants have different operating characteristics. The electricity supply system needs to be sufficiently flexible in its operation to respond to variations in the performance of the other types of generators in the system.

In this report only technologies that generate electricity are considered. Technologies that reduce electricity demand, such as solar hot water systems, are beyond the scope of this report.

1.4.2 Supplying Electricity for the Load Duration Curve

In supplying the electricity requirements it is generally considered that the overall cost of electricity for the State should be minimised and the electricity market is designed to facilitate this. Power plant operators have an incentive to bid in at their marginal price of production, which is essentially their fuel cost.

Generating companies select plant types to suit the application, so that to supply a very large quantity of electricity they would select a plant with good economies of scale and low fuel costs, resulting in the production of low cost electricity. On the other hand if a generating company wanted to supply load at peak times they would try to minimise the investment cost, as most of the time the plant would not be producing electricity. They would also not be too concerned about the fuel cost as at the times of very high load the electricity pool price can be very high, enabling them to recover both the fuel cost and the capital over a short generating period.

Consequently the plants that supply the base load are those with the lowest marginal cost of generation, once they have been installed. Typically these would be coal fired plants with low cost coal, nuclear plants, if there were any, combined cycle gas turbine plants with take or pay gas contracts and renewable energy plants such as wind turbines, solar, and some biomass plants that effectively have zero marginal cost.

Hydro plants also have zero marginal price, but because they can be turned on and off quickly, responding the fastest of all plant types, they can be used to supply the peak load and obtain a higher price for their electricity.

Currently the most likely plant to be installed to supply the peak load are open cycle gas turbines, as they have the lowest investment cost. There is limited additional hydro capacity in NSW for this purpose. Any plant that is used to supply a load at the time of peak demand must be able to do so reliably if electricity shortages are to be avoided.

Electricity generating plants that run at capacity factors between the peaking and base load are called intermediate load plant. Typically these plants could operate in the capacity factor range of approximately 10 % to 50%. They might include open cycle gas turbine plant operating at higher than expected capacity factor, combined cycle plant or coal fired plant with relatively high cost fuel. The market conditions and marginal generation cost determines which plants fulfil this role.

In the following discussion for each technology the way in which each can supply the base load will be discussed. Some renewable sources and technologies have the capability to supply large amounts of energy, but due to the potentially irregular nature of their supply it must be able to be supplemented with other firm capacity on occasions.

1.4.3 Greenhouse Gases

A number of gases associated with the combustion of fossil fuels contribute to the enhanced greenhouse effect. They include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF_6). (GES, 2006).

However the most significant greenhouse gas associated with the combustion of fossil fuels is carbon dioxide. This study, as defined by the Owen Inquiry, focuses on carbon dioxide as the main greenhouse gas. It is also recognised that fugitive emissions from gas production and coal mining are also significant.

1.5 Report Structure

The report is divided into components corresponding to the deliverables defined by the work scope:

– Review of the prospective generation technologies is covered in Chapters 2, 3 and 4.

– The carbon capture and disposal technologies are discussed in Chapters 5 and 6

– The applicability of new base load generating technologies to the NSW operating environment is discussed in Chapter 7.

– The characterisation of the existing NSW generating facilities is covered in Chapter 8.

– A Summary is provided in Chapter 9

2. Identification of Prospective Generation Technologies

2.1 Existing NSW Generation

At present, NSW relies on coal based thermal power generation for the bulk of its base load electricity production. The most modern of the NSW major coal based generating plants was commissioned in 1992/93 and the oldest in 1969. Between 1980 and 1986 there were 9 new units commissioned, resulting in an average unit age of 27 years. The coal based technology used in NSW power stations is pulverised coal firing, which was first used in the 1950s and has been subjected to continuous improvements in performance and capacity since that time. In addition, base load power is supplied through inter-connectors from Snowy/ Victoria and Queensland.

In recent years, due to the pressure of greenhouse issues, and the introduction of related measures, there has been the installation of very small capacity increments of wind, biomass and mine drainage methane fuelled plants. At present there are a number of natural gas fired base load and peaking units either planned or under construction. To date hydro power has provided peaking and intermediate electricity to NSW. The characteristics of the existing NSW generators are discussed in Chapter 8. Typical characteristics of major NSW power plants are provided in Table 2.1.

Parameter	Units	Range
Unit capacity	MW	350 – 690**
Number of units		20 (across 7 power stations)
Fuel type		NSW steaming coal
Technology		sub-critical; pulverised coal fired
Greenhouse intensity	CO_2 kg/MWh(SO)	860 - 1065
Forced outage rate	%	0.5 – 9.5

** Operating above nameplate of 660 MW

Table 2.1. Characteristics of Current NSW Coal Fired Power Stations
(based on data provided by NSW generators)

2.2 Prospective Generation Technologies

There is a range of electricity generation technologies that are presently used around the world. For this study the technologies have been categorised according to fuel type. Some of the technologies are established and proven, others are considered to be prospective.

Table 2.2 lists the technologies that were identified for consideration in this study.

Non-Renewable Technologies	Renewable Technologies
• Natural gas fired gas turbine (open cycle) • Natural gas fired gas turbine (combined cycle) • Ultra-supercritical Pulverised Coal • Integrated Coal Gasification Combined Cycle • Fluidised bed coal combustion • Pressurised fluidised bed coal combustion • Co-utilisation of coal with natural gas • Ultra Clean Coal Combined Cycle Gas Turbine • Nuclear	• Hydro • Wind • Solar • Biomass • Geothermal / Hot Rocks • Ocean - tidal / wave generation

Table 2.2 Technologies Considered in Study

These technologies and their inclusion in the study are discussed in detail in chapters 3 and 4.

2.3 Assumptions

2.3.1 Fuel Cost

A critical input to the variable operating costs of a power plant is the fuel costs. With coal and to a lesser degree gas, the location of the plant within NSW will have a significant influence on the fuel cost. Another variable is the timeframe for the use of the resource. To allow the various technologies to be compared, ranges of fuel prices have been used, based on data published by ACIL Tasman (2007). The ranges used in (2007/08) $/GJ are:

	2011/12	2026/27	assumed for study
Coal	$0.96 - $1.56	$0.94 - $1.50	$0.95 - $1.53
Natural Gas	$2.38 - $4.53	-	approx. $4

2.3.2 Coal Properties

As it is outside of the scope of this study to consider specific sites, the assumed coal properties are those of the NSW reference coal specified in the Generator Efficiency Standards (AGO, 2006). The relevant properties of this coal (BLC2 in Table F.2 of AGO, 2006) are:

Total Moisture (a.f)	7.5%
Ash (a.f)	21.2%
Specific Energy (a.f)	24.4 MJ/kg
CO_2 emission factor	90.1kg CO_2/ GJ fuel

These properties were used for all efficiency estimates, annual coal consumption figures and greenhouse intensity calculations for coal technologies presented below. It is expected that, depending on the site selected for a future coal fired plant, the actual as-fired ash level may be significantly higher than that provided above.

2.3.3 Unit Size

It has been assumed that the base load increment size will be between 500 and 1000MW. For natural gas fired plant, capacities of 400MW and 800MW have been considered.

2.3.4 Emissions Limits

The emission limits (Table 2.3) prescribed by the Protection of the Environment Operations (Clean Air) Regulation 2002 (POEO, 2002) have been assumed to apply to a new large power plant being built in regional NSW. The actual limits imposed by the EPA would depend on the technology, fuel selected and plant location.

Pollutant	Units	Limit
Particulate	mg/Nm^3	50
Nitrogen oxides	mg/Nm^3	500
Sulphur dioxide	mg/Nm^3	no limit; controlled via licence for S in coal

Table 2.3 Assumed Emissions Limits for New NSW Power Plant

2.3.5 Currency Exchange Rate

Where cost data has been obtained from international sources and conversion has been required, the following exchange rates have been used:

1 A$	0.85US$
1 A$	0.64 Eur

2.3.6 Plant Construction Costs

Where available, ranges of plant construction costs or approximate costs have been provided for each technology. Market forces for power generation equipment have a large influence on the final construction cost. This is very difficult to predict for an EPC specification that may be put to Tender in 2008 or beyond.

Between 2001 and 2007 there has been a significant increase in the tendered costs for power plant due to increased demand. This has resulted in shortages in manufacturing capability for power plant equipment, increases in material costs and the availability of experienced contractors. This situation applies to all power plant sectors and includes both existing and new technologies. This has also had the effect of outdating existing cost data bases and most recent studies reporting the cost of thermal power plant technologies and estimated costs of emerging low emission technologies.

Factors influencing the tendered price include:

– Commodity prices for resources such as steel
– Country of manufacture
– Contractor home country
– Labour costs
– The number and capacity of suppliers tendering.

Therefore the accuracy of any costs quoted is expected to be ±30% for Western style suppliers. All values quoted are in 2007 Australian dollars.

Costs for plant that is still in the early stages of development are difficult to predict, particularly for plants that are being developed overseas. In these cases the upper band on estimated costs may be in error by up to 100%, and care should be exercised when using this data.

2.3.7 Level of Maturity of Technology

The level of maturity of a technology is an important consideration for any technology that would supply a significant proportion of the States electricity and is likely to be installed within the next few years. The level of maturity can impact on the system reliability and the ability to finance a project. Providers of finance for power projects are risk averse and an unproven technology would find it difficult to obtain support. To facilitate the discussion on the level of maturity of various technologies in this report, the following terminology (IPCC) has been adopted:

> Research Phase means that the basic science is understood, but the technology is currently in the stage of conceptual design or testing and has not been demonstrated in a pilot plant.
>
> Demonstration Phase means that the technology has been built and operated on the scale of a pilot plant. But further development is required before the technology is ready for design and construction of a full-scale system.
>
> Economically Feasible under specific conditions means that the technology is well understood and used in selected commercial applications, for instance if there is a favourable policy measure in place with few (less than 5) replications of the technology.
>
> Mature Market means that the technology is now in operation with multiple replications of the technology worldwide.

There will be cases where technologies may cross over these definitions, for example wind turbine technology has many thousands of replications but is also supported by policy measures. Given this type of situation an overall consideration has been taken of where the technology sits within the cost spectrum.

It is also likely that some technologies on an overall basis may be comprised of technologies that are in different phases in the development spectrum. In these instances the operation of the overall concept and its ability to produce electricity in its own right will be taken.

3. Non-Renewable Technologies

The following sections describe available non-renewable electricity generation technologies. Options discussed include technologies utilising coal, gas and nuclear fuels.

A number of technologies listed in Table 2.2 have not been included for consideration as prospective base load plant for NSW. These technologies are fluidised bed combustion and pressurised fluidised bed combustion.

> Fluidised bed combustion (FBC) in its various forms offers a technology that can be designed to burn a variety of fuels. In FBC plant, combustion of the solid fuel takes place within a fluidised bed where inert material, fuel and sulphur sorbent are maintained in suspension by ascending air flow. FBC systems fit into two groups, non-pressurised systems (FBC) and pressurised systems (PFBC), and two subgroups, circulating (CFBC) or bubbling fluidized bed.
>
> During the past decades, FBC technology has undergone considerable technological and commercial development towards improved performance and lower construction cost (Gurba, 2007). It has found a variety of applications ranging from small industrial boilers and furnaces to large power generation units. Circulating fluidised bed combustion systems offer an alternative to pulverised fuel (PF) plants, with the advantage of being able to utilise low grade, high sulphur, variable quality coal, plus biomass and wastes. FBC has now become the most widely applied clean coal technology after pulverised fuel plants with flue gas desulphurisation. However, the technology currently operates at relatively small sizes. There are hundreds of CFBC units operating worldwide, including a number of plants as large as 250 to 300 MWe, while larger units up to 460MWe are under construction. A 460MWe supercritical unit is under construction at Lagisza, Poland. This plant is due to start-up at the beginning of 2009.
>
> In Australia, Redbank Power Station, near Singleton, NSW has operated a 150 MW CFBC boiler since 2001.
>
> Pressurised Fluid Bed Combustion was initially developed (during 1990s) with a view to achieving improved conversion efficiency and more effective sulphur and nitrogen oxide control than was then available from conventional pulverised coal fired plant. A limited number of commercial plants have been built to date, including in Japan where Australian coal is a major fuel source. Recent advances in conventional technology have reduced the benefit available from PFBC technology, and the major issue likely to affect coal based power generation in the future appears to be CO_2 capture and storage. In this PFBC appears to offer few benefits over PF technology. Few new orders have been placed in recent years and it appears that this technology may remain a relatively small player in the future power technology market. PFBC technology is not further discussed in this report.

3.1 Pulverised Coal with Ultra-supercritical Steam Conditions

Although the most modern coal fired power plant in NSW was commissioned in the early 1990s, the overall plant design is similar to the oldest plant which was commissioned in 1969. These plants operate with steam temperature of 540C and pressure of 16.8MPa. These steam conditions are referred to as *subcritical* as the pressure is lower than that of the critical point of water (22.1MPa, 374.2C). Above the critical pressure of water liquid and vapour can co-exist in equilibrium as a supercritical fluid.

During the 1980s, due to concern over the greenhouse issue, countries such as Japan, Germany and Denmark embarked on programs to increase the thermal efficiency of the coal fired conventional steam cycle. Significant advances were made via the design of plants with supercritical steam conditions.

3.1.1 Description

The supercritical boiler is significantly different from a subcritical boiler in a number of ways. Above the critical pressure of water, the density of steam and the density of water are equal and there is no distinction between the two states. The ability to separate steam from water no longer exists, therefore steam drums are redundant and supercritical units are of a once through design. As water is not being recirculated through water wall tubes for evaporation, the quantity of water available to cool the furnace wall tubes is far lower. Furthermore, the temperature of the fluid in the tubes will vary as there is no saturation state in supercritical pressure steam.

In the pursuit of even higher efficiency than achievable with supercritical steam conditions, utilities in Japan and Denmark have adopted steam cycles with pressures and temperatures that have been called *Ultra-supercritical*. From the literature there does not seem to be a precise definition of ultra-supercritical steam conditions. GE turbine literature suggests that throttle temperatures greater than 566C represent ultra-supercritical conditions. The US DOE suggest 4500psi (31Mpa) and 1100F/1100F/1100F (593C).

There is a strict definition of supercritical conditions based on the critical point of water. As discussed above, this forces a boiler design to go from a drum type boiler to once-through. As there is no significant difference in plant hardware between supercritical and ultra- supercritical conditions, the lack of precise definition of ultra-supercritical is of no consequence. Ultra-supercritical plants are only distinguished by specified temperatures, pressures and resultant material selections (Figure 3.1a)

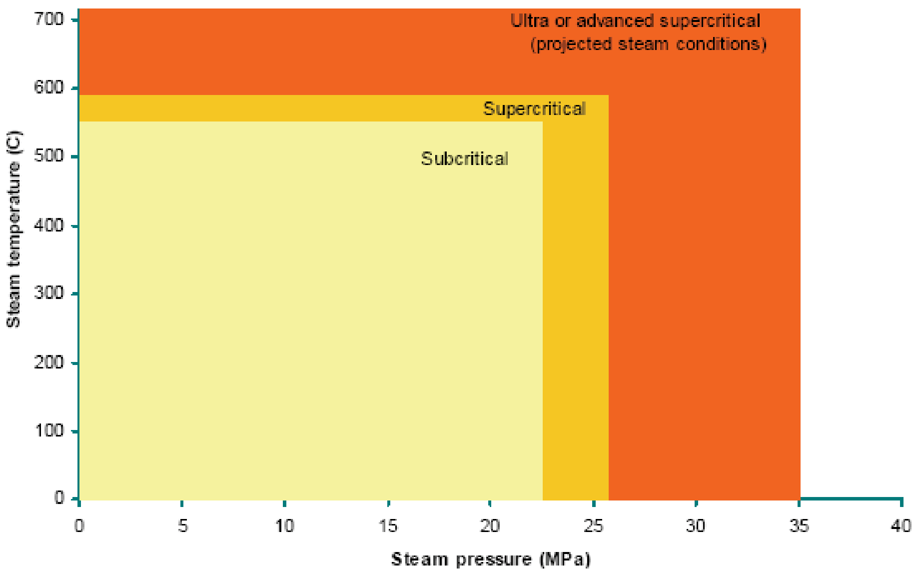

Figure 3.1a Steam Conditions for Coal Fired Plant Classifications (from Wibberley, 2006)

Main steam cycle conditions in the vicinity of 600°C and 30MPa are now achievable with available materials and designs. (CCSD, 2006) This so called advanced or ultra-supercritical technology may have thermal efficiencies one or two percentage points higher than currently installed supercritical technology. It is expected that the steam conditions of a new base load supercritical plant for NSW would have main steam conditions of 580C, 29MPa and a reheat steam temperature of 600C. Figure 3.1b shows a schematic diagram of a typical ultra-supercritical steam cycle.

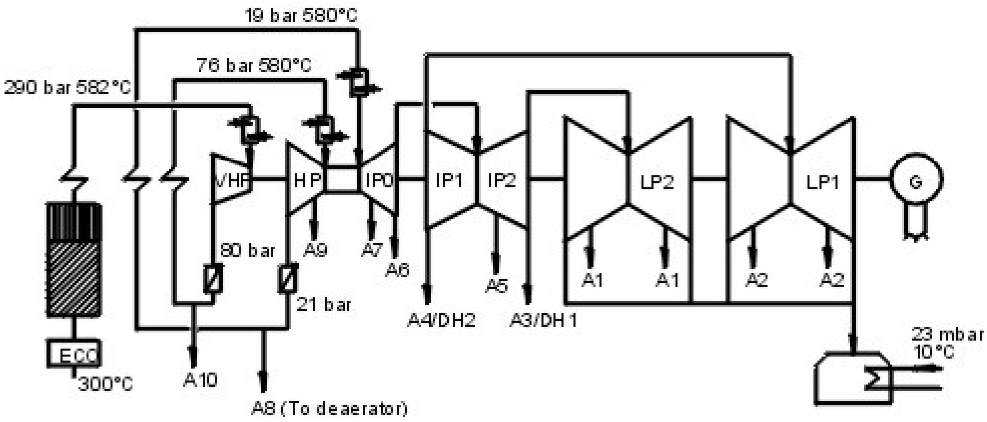

Figure 3.1b Ultra-supercritical Steam Cycle Schematic (Kjaer, 2007)

3.1.2 Performance

For a coal fired unit of between 500 and 1000MW capacity, with the steam conditions specified above, the sent out thermal efficiency is expected to be around 41% for a wet cooled plant and 39% for a dry cooled plant based on Connell Wagner thermodynamic modelling. These values are consistent with the 41.2% (wet cooled) and 39.7% (dry cooled) quoted in AGO, 2006 for the NSW coal case. The actual value would depend on the detailed plant specification and site ambient conditions.

The required coal properties for supercritical pulverised coal fired plants are no different to existing sub-critical plant. The coal preparation, combustion, dust collection and disposal systems are the same design as existing subcritical plant. Coal consumption has been calculated for a plant operating at 90% capacity factor with the assumed thermal efficiencies and coal properties provided in section 2.3.2, and is presented in Table 3.1. Should the actual coal ash level be greater than the nominal value provided in section 2.3.2, the coal consumption figures will also be higher.

	Wet Cooled	Dry Cooled
Sent out thermal efficiency %	41	39
Annual coal consumption (tonnes)		
1000MW unit size	2,860,000	3,010,000
500MW unit size	1,430,000	1,500,000

Table 3.1 Ultra-supercritical plant coal consumption (see text for references)

As most of a supercritical unit's components are identical to a sub-critical unit's, the reliability and availability are expected to be identical to that of existing sub-critical plant. Improvements in materials, design and experience have led to this situation. The detailed engineering of the overall plant will have more influence on the reliability than the issue of steam condition selection.

Current literature indicates that the reliability of new supercritical units is expected to be equivalent to subcritical units. In the USA, a comparison of the reliability of subcritical and supercritical units in the size range 400 – 850 MWe found that availability, equivalent forced outage rate (EFOR) and capacity factor were statistically similar for both technology types (NERC, 2006).

In the last 15 years there has been more than 20,000MW of supercritical plant built throughout the world (based on Connell Wagner database). These units have ranged in size from 385 to 1050MW, and include 5 units of around 450MW in Queensland. Of these plants more than 8,000MW had main steam temperatures of 600C and above and therefore may be categorised as ultra-supercritical. Apart from Australia, countries with supercritical coal fired plants in operation include Germany, Denmark, Japan, China, India and the USA. It has been reported (Topper, 2006) that there is 22,000MW of supercritical plant currently under construction in China and 17,600MW of plant under construction in India. The technology is therefore considered to be well established and mature.

It is expected that a new base load ultra-supercritical coal fired plant built in NSW would be technically capable of achieving a capacity factor of 90%. Provided that the plant is designed for the site climatic conditions, the maximum output of the plant should be available whenever the plant is in service.

3.1.3 Environmental

The NSW emissions limits for particulate emissions would be met by fabric filter plant and NOx emissions by low NOx combustion systems. The higher sent out efficiency of supercritical units results in lower emissions of SOx, NOx and particulate per MWh(SO) of electricity production than subcritical units with similar stack levels of pollutants.

Water requirements are an issue for any new power plants in eastern Australia. Unless sited on the coast, any coal fired plant would require a dry cooling system. Dry cooling results in a lower thermodynamic cycle efficiency compared with wet cooling and higher construction costs for the same plant. Water requirements for the wet and dry cooling options are provided below. These values have been computed by Connell Wagner for recent conceptual studies of NSW and Queensland power plants. They are consistent with the wet cooled values contained in AGO(2006).

	Wet Cooled	Dry Cooled
Raw Water Use (kg/MWh(SO))	1800 - 1900	130 - 140

Specific CO_2 emissions are primarily a function of plant sent out thermal efficiency. The following are indicative values for the two cooling system options, assuming 100% coal firing. These values are also consistent with the AGO (2006) values.

	Wet Cooled	Dry Cooled
CO_2 emissions intensity (kg/MWh(SO))	785 - 820	820 - 860

It may be possible to reduce these values via supplementary firing with biomass, natural gas, coal seam methane or mine ventilation air.

Other environmental aspects affecting the suitability of coal fired plant include the ability to dispose of wastes such as ash. Brine disposal necessary for inland power stations with treatment systems to remove salts from cooling water are not required for dry cooling.

3.1.4 Financial Factors

Based on the above plant specification, efficiency values and using the assumptions described in Section 2.3, the estimated costs are summarised in Table 3.2. Construction costs were estimated by Connell Wagner based on recent experience with supercritical plant projects in Queensland and NSW. The value quoted is consistent with US experience. (Dalton *et al* , 2007). The coal cost per MWh(SO) was computed using the fuel cost specified in Section 2.3.1 and the thermal efficiency provided above. The variable operating or maintenance cost component is comprised of the cost of consumables such as water, chemicals and lubricants and variable O & M costs associated with ash handling and disposal. Based on Connell Wagner experience with similar technology plant, we expect that the variable O & M component would be in the range of 1.1 to 1.5 $/MWh(SO).

	Wet Cooled	Dry Cooled
Construction cost (A$/kW)[#]	1400 - 1900	1450 - 1950
Operating and maintenance costs		
Coal ($/MWh(SO))	8.3 – 13.4	8.8 – 14.1
Variable O&M (excluding coal) ($/MWh(SO))	1.1 – 1.5	1.1 – 1.5
Fixed O&M ($/MW/yr)*	40,000	40,000

Table 3.2 Ultra-supercritical Plant Estimated Construction and Operating Costs [# based on Connell Wagner experience with supercritical technology; * from ACIL (2007)]

Given the maturity of ultra-supercritical technology and the extent of common components with existing technologies, there are not considered to be any undue project delivery risks of Ultra-supercritical (USC) electricity generation technology.

3.1.5 Suitability for Base load in NSW

Supercritical or ultra-supercritical pulverised coal fired power generation is suitable for base load generation in NSW, however although the greenhouse gas emissions are lower than existing coal fired plant (Table 2.1) they are still significant. As discussed in Chapter 5 there are a number of options for CO_2 capture available for this technology.

3.2 Combined Cycle Gas Turbine

3.2.1 Description

Gas turbine engines are very commonly used for electrical power generation. Typically, in a gas turbine, a gaseous or liquid fuel is continuously injected into a combustion chamber charged with high pressure air. The hot high pressure combustion products expand through a gas turbine causing it to spin on its shaft similar to a fan. The gas turbine is coupled to an electrical generator which produces electricity.

The two most common gas turbine configurations for power generation are referred to as open cycle and combined cycle. The combined cycle mode uses the waste heat from the gas turbine exhaust to produce steam. The steam is then used to drive a steam turbine coupled to an electrical generator. Additional power is produced by the otherwise wasted gas turbine exhaust heat. The combined cycle is more efficient than the open cycle configuration. Open cycle plant is often used as peaking plant. That is, it spends most of its time on standby starting infrequently to supply periods of peak demand. The combined cycle machine with its higher efficiency is more usually applied to intermediate or base load. The application of open cycle and combined cycle, as described, is driven by economics rather than technology.

Combined cycle plant can be supplied in different configurations. A combined cycle block refers to a number of gas turbines, usually one to three, whose waste heat is used to generate steam in a heat recovery steam generator (HRSG) supplying one steam turbine. A significant amount of cooling is required to condense the steam as it exhausts from the steam turbine. The condensed steam is pumped back to the heat recovery steam generators for reuse.

There are several ways of providing condenser cooling. Three common methods are once through sea water cooling, closed circuit water cooling with an evaporative forced draft cooling tower and air cooled condenser. The choice of cooling system impacts on MW output, fuel efficiency, emissions, water consumption and cost.

Gas turbine power generation equipment is mature technology available from a number of suppliers. The lead time for equipment supply can vary significantly depending on world demand.

3.2.2 Performance

Gas turbines can be fuelled by many liquid and gaseous fuels. Common fuels are distillate and natural gas. Some gas turbines are provided with dual fuel capability. In this case a quantity of liquid fuel may be stored on site as backup fuel should there be an interruption to the supply of the natural gas fuel.

Table 3.3 indicates fuel consumption for Combined Cycle Gas Turbine blocks in the 400MW and 800MW range. The fuel is natural gas and consumption is in PJ/annum based on 90% capacity factor. The fuel consumption rates were developed from Thermoflow's GTPRO (2007) modelling software. Three scenarios are considered:

- Once through seawater (20°C) cooled, ambient conditions 25°C, 101.3kPa and 60% relative humidity
- Closed circuit water cooling with forced draft evaporative cooling tower, ambient conditions 25°C, 98.4 kPa, 60% relative humidity
- Air cooled condenser, ambient conditions 25°C, 98.4 kPa, 60% relative humidity

Fuel efficiency is greatest for once through seawater cooling and least for air cooled condenser. The higher cooling temperature typically reduces MW output by approximately 6% while reducing fuel consumption by 3%.

	Sea Cooled	Wet Cooled	Dry Cooled
Sent out thermal efficiency %	51.3 – 51.2	50.6 – 50.7	49.8 – 49.9
Annual gas consumption (PJ) @ 90%cf			
400MW block size	22.1	22.4	22.8
800MW block size	44.2	44.8	45.6

Table 3.3 Fuel (natural gas) consumption versus combined cycle block size

There is a range of reliability and availability outcomes possible from gas turbine plant. Whether a particular plant realises high or low reliability and availability depends on a number of factors including suitability of plant to application, fuel quality, quality of manufacture and construction and quality of operation and maintenance. Availability in the range 85 to 95% is considered achievable.

Large combined cycle blocks range in size from approximately 200 to 900 MW-sent out. A characteristic of gas turbines is that MW output is limited by ambient conditions. Increasing air temperature and also elevation reduces output. This can be compensated for by inlet air cooling equipment with an increase in water consumption and/or auxiliary load.

3.2.3 Environmental

As with the fuel consumption rates reported in the previous section GTPRO was used to obtain a typical range of CO_2 emission and water consumption values. Again the following three scenarios were considered:

- Once through seawater (20°C) cooled, ambient conditions 25°C, 101.3kPa and 60% relative humidity
- Closed circuit water cooling with forced draft evaporative cooling tower, ambient conditions 25°C, 98.4 kPa, 60% relative humidity
- Air cooled condenser, ambient conditions 25°C, 98.4 kPa, 60% relative humidity

Table 3.4 indicates CO_2 emissions for 400MW and 800MW combined cycle block sizes and three cooling approaches. CO_2 emission ranges from 345 to 354 kg/MWh(SO) sent out.

CO_2 Emission (kg/MWh-sent out)			
cooling	sea	wet	dry
400 MW (nominal)	345	349	353
800 MW (nominal)	345	348	354

Table 3.4 CO_2 emissions for 400MW and 800MW block size

Water consumption is greatest where evaporative cooling is employed. The relatively low underlying consumption shown for dry air cooling and seawater cooling is due to steam cycle makeup and gas turbine inlet air cooling. It is assumed that with seawater cooling, a once through cooling system with no make – up is used. Table 3.5 indicates water consumption for a range of plant size and three cooling approaches.

Fresh water consumption (kg/MWh-sent out)			
cooling	sea	wet	dry
400 MW (nominal)	21	970	22
800 MW (nominal)	21	970	22

Table 3.5 Water consumption versus combined cycle block size

The wet cooling case has significantly higher water consumption than either the sea cooled or dry cooled option due to the significant make – up water requirement of a plant with wet cooling towers.

3.2.4 Financial Factors

GTPRO (2007) was used to estimate construction cost for 400MW and 800MW plant sizes for the following three cooling options.

- Once through seawater (20°C) cooled, ambient conditions 25°C, 101.3kPa and 60% relative humidity
- Closed circuit water cooling with forced draft evaporative cooling tower, ambient conditions 25°C, 98.4 kPa, 60% relative humidity
- Air cooled condenser, ambient conditions 25°C, 98.4 kPa, 60% relative humidity

Table 3.6 summarises the construction cost of generic 400MW and 800MW combined cycle blocks for the 3 cooling methods. As a check the Tallawarra 435MW Alstom KA26-1 combined cycle plant was also modelled. The GTPRO (2007) estimated cost is $740/kW or $320 million. This estimate compares well to the amount of $350 million (Modern Power Systems, March 2007, p.11-14) for the combined cycle plant being built at Tallawarra.

Capex ($/kW)			
	sea	wet	dry
400 MW- nominal sent out	833	861	940
800 MW- nominal sent out	800	826	906

Table 3.6 Combined cycle block construction cost

For a range of combined cycle block size and cooling approaches modelled with GTPRO annual operating and maintenance costs (excluding fuel, interest and depreciation) are estimated at 5% of the construction cost. For a 435 MW-sent out plant with construction cost $817/kW operating and maintenance cost is estimated at $18 million per year.

According to data published by ACIL Tasman (2007) annual fixed operation and maintenance costs for combined cycle plant are $12,800/MW. Variable costs are estimated at $4.85/MWh(SO) (ACIL Tasman 2007). For a 435 MW-SO combined cycle plant operating at say 90% capacity factor over one year the total operating and maintenance cost based on ACIL Tasman (2007) is estimated at $22 million. This is somewhat higher than the 5% of construction cost estimate of $16 million.

An estimate of operating and maintenance costs for combined cycle plant in the United States USDOE-EIA (2007) is lower again at USD1.94/MWh(SO) for variable and USD11,750/MW fixed in 2005 USD. Assuming inflation of 3% per year and the exchange rate quoted in section 2.3.5 the USDOE estimates become $2.43/MWh and $14,700/MW in Australian dollars. For the 435 MW-sent out, 90% capacity factor example above total operation and maintenance cost is $16 million.

Table 3.7 summarises the operation and maintenance costs for 400MW and 800MW block sizes for the three cooling methods.

O&M COST @ 90% CF	$million/pa		
	sea	wet	dry
400 MW- nom sent out			
ACIL-Tasman	20.7	19.8	19.5
GTPRO	15.3	15.1	16.3
USDOE	13.7	13.1	
800 MW- nom sent out			
ACIL-Tasman	41.4	39.7	39.0
GTPRO	29.3	29.0	31.3
USDOE	27.4	26.1	25.8

Table 3.7 Summary of operation and maintenance costs

Gas fuel cost estimates by ACIL Tasman (2007) estimate gas price to Smithfield and Tallawarra to be $3.63 to $4.00/GJ respectively. Assuming a gas price of $4/GJ then fuel cost for a range of combined cycle block sizes and cooling options varies from approximately $28 to $29/MWh(SO). The fuel cost estimates are shown in Table 3.8. The higher heating value of the natural gas is assumed to be 51.2 MJ/kg.

Fuel cost at MCR ($/MWh(SO))			
	sea	wet	dry
400 MW- nom sent out	28.1	28.5	28.9
800 MW- nom sent out	28.0	28.4	28.9

Table 3.8 Estimated CCGT Fuel Costs

It should be noted that fuel consumption and cost ($/MWh(SO)) are at maximum output from the combined cycle block. Part load operation of a block will generally be less efficient, using more fuel resulting in a higher specific fuel cost.

Natural gas combined cycle plants are a mature technology with tens of GW of installed capacity world wide. There are therefore no specific technology risks for project delivery.

3.2.5 Suitability for base load in NSW

Combined cycle technology is suitable for base load operation in NSW provided gas supply can be secured at an economic price. The CO_2 emissions are significantly less than existing coal fired generation.

According to the International Energy Agency (IEA, 2006), the principal barrier to the further expansion of CCGT technology is uncertainty about future natural gas prices. Fuel costs account for 60 to 85% of total generation costs for CCGTs, much higher than for other power generation technologies. An increase in fuel prices would therefore have a more serious impact on the economics of an CCGT plant than on other technologies

3.2.6 Open Cycle Gas Turbine Construction Cost

GTPRO was used to obtain construction costs for a range of open cycle gas turbine sizes. The estimate assumptions are as follows:

- Ambient condition, 25 °C, 98.4 kPa, 60% relative humidity.
- Single gas turbine only.
- Inlet cooling included.

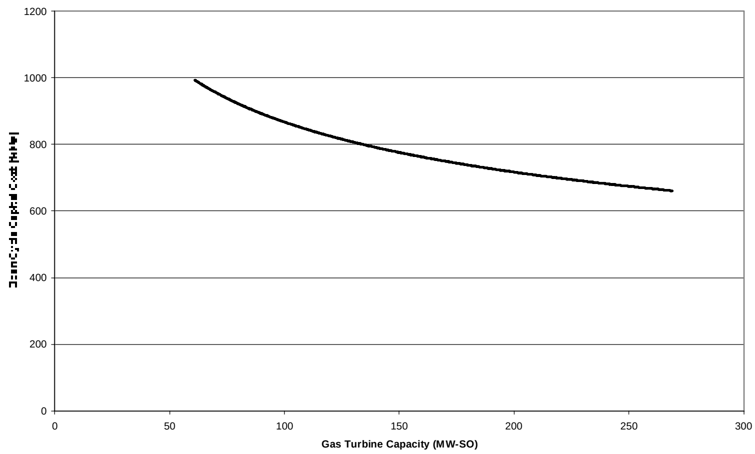

Figure 3.2 Open Cycle Gas Turbine Costs and Capacity

3.2.7 Conversion of Open Cycle to Combined Cycle

Proponents of power plant projects often consider the option of initially installing an open cycle gas turbine and then as the electricity demand increases, convert it to combined cycle operation. This is a valid option but has the following issues:

– Open cycle machines and combined cycle plants are normally optimised for their duty cycle

– Conversion from open cycle to combined cycle will not produce an optimal result.

– An increase in electricity demand will not necessarily change the shape of the load duration curve. Therefore the conversion of an open cycle GT to combined cycle will require another open cycle GT. If this process were perpetuated, the system may end up with a fleet of sub-optimal CCGTs.

3.3 Integrated Gasification Combined Cycle

3.3.1 Description

Integrated gasification combined cycle (IGCC) is an advanced power generation technology that has been developed to achieve high thermal efficiencies and lower environmental emissions than conventional coal based thermal power generation technology. Figure 3.3 provides an overview of a typical IGCC cycle.

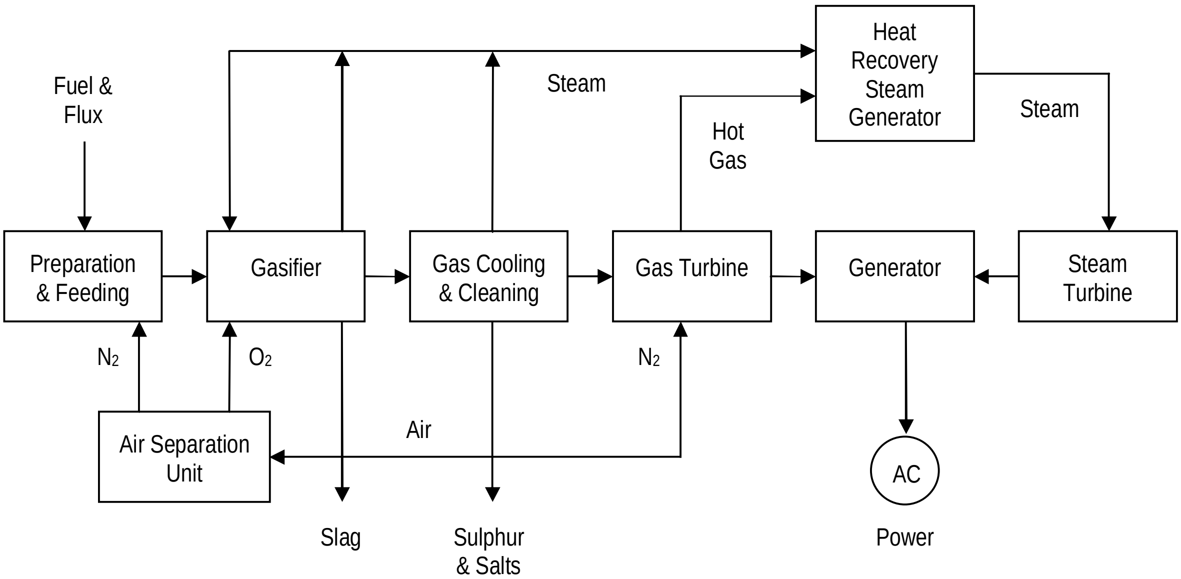

Figure 3.3 - Typical IGCC system

Fuel is fed into the gasifier with an oxidant, usually oxygen (O_2), under reducing conditions to produce a synthetic gas (syngas) mixture primarily containing carbon monoxide (CO) and hydrogen (H_2). Particulate matter and some gases including ammonia, chlorides and those containing sulfur are removed from the syngas before it enters the gas turbine. Waste streams typically comprise of slag (molten ash), sulfur and salts which can be potentially sold by the plant operators. After gas clean up, the syngas is fed to the gas turbine where it is burnt. The combustion of the syngas produces a hot gaseous product which then expands through the gas turbine producing power. The sensible heat in the exhaust gas is then utilised in a steam cycle by passing it through a Heat Recovery Steam Generator (HRSG) which is basically a system of convective heat exchangers. The steam from the HRSG drives a steam turbine and generator, resulting in power production. The gas turbine, HRSG, steam turbine and generator are essentially the same as standard combined-cycle power plant.

For high throughput in a compact vessel, most gasifiers operate at high pressure. In the case of oxygen blown gasifiers an air separation unit supplies oxygen to the gasifier and nitrogen to the gas turbine for NO_x control. There are a range of options for the integration of the steam and air/gas cycles. A higher level of integration provides a higher thermal efficiency but at the demonstration stage of some IGCC systems it was found to be detrimental to availability and flexibility of operation, due to the increased plant complexity.

All of the plant and sub processes used in an IGCC facility and described above are commercially available and currently used in the petroleum, chemical and power industries. There are over 22 gasification facilities worldwide producing power. Several of these facilities also co-produce steam, hydrogen, heat or methanol. The larger plants, greater than 200MW, use coal or petroleum residues as fuel. Of these only four use high rank coal such as that available in NSW. These four plants were commissioned between 1994 and 1997 as demonstration plants and range in size from 280MW to 320MW (gross). The technology is therefore available now, however system maturity is significantly lower than ultra-supercritical (USC) boiler technology due to the small number of plants in operation and smaller unit sizes. Due to the technology risk and higher construction costs commercial risk is higher.

A number of major research and development programs are underway in the USA, Europe, Japan and China to further develop IGCC technology to include carbon dioxide (CO_2) capture technology to facilitate sequestration. After the conventional syngas cleanup stage and prior to the gas turbine, the syngas composition is shifted in a reactor to maximise CO_2 and H_2 concentrations. The CO_2 is then extracted for sequestration leaving a H_2 rich stream which can be used to produce power in a gas turbine, power in a fuel cell, transport fuels, or chemicals. These programs aim to reach their objectives in the 2015 - 2020 timeframe.

The FutureGen project in the USA and ZeroGen project in Queensland are examples of this technology.

3.3.2 Performance

IGCC is suitable for a variety of fuels including coal, petroleum coke/residues, biomass and municipal waste. Numerous gasifier types including fixed bed, fluidised bed and entrained flow, plus different configurations for each type, have been developed by manufacturers to accommodate the wide range fuels.

The rate of fuel consumption is related to the net thermal efficiency of the system. IGCC is seen to have a similar net thermal efficiency to USC, for large scale base load plant. For NSW this is estimated to range between 40% and 42% on a Higher Heating Value (HHV) basis

The operating experience of demonstration and commercial gasification plants has not been without problems. The problems have been usually associated with lack of operating experience on new fuels, deviations from the design fuel and new plant configurations and systems. Due to these operating difficulties lower annual availabilities on syngas compared to typical combined cycle stations have been experienced. The availability of a combined cycle station is often over 90% however with the addition of gasification and clean-up plant, in a single train, experience to date has shown it being significantly reduced to 80% or less. The reasons for lost availability and production are numerous and differ between different plant configurations. However in operating IGCC plants they have included:

- Convective cooler fouling
- Slag removal difficulties
- Gasifier burner and refractory wear
- General erosion and corrosion in gasifier
- Flame induced pressure oscillations in the gas turbine
- Ceramic filter element failure
- Coal and slurry feed issues - unsteady feed rates and slurry solids settling

US EPA (2006) estimate that availabilities of 85% and higher should be achievable in future IGCC plants, particularly where multiple gasifiers are justified for the unit size, compared with 90% and higher in supercritical pulverised coal plants. The technical capacity factor is assumed to equal the maximum availability and therefore is estimated to be 85% for the purposes of this study.

3.3.3 Environmental

Compared with conventional pulverised coal boiler or fluidised bed technologies, environmental emissions are significantly reduced with IGCC. The control of NOx and SOx emissions are an integral part of the IGCC process. Particulates are filtered and/or scrubbed from the system and the syngas is cleaned of precursors of NO_x and SO_x prior to entry into the combustion turbine. This greatly reduces emissions to the atmosphere and land as shown in Table 3.9. (US EPA, 2006)

Environmental Impact	(kg/MWh(SO))
NO_x (NO_2)	0.161
SO_2	0.141
Particulate Matter	0.023
Solid Waste	29
Raw Water Use	2,250

Table 3.9 IGCC environmental impact (US EPA 2006)

For a wet cooled system raw water consumption is similar to or less than ultra-supercritical coal plant as the cooling required in the power cycle is more like that in Table 3.5 for Combined Cycle Gas Turbine plant:

	IGCC (slurry fed gasifier)
Raw Water Use (kg/MWh(SO))	1750# - 2,250*

*US EPA (2006). # Ikeda et al , (2006)

For a dry cooled system raw water consumption is expected to be higher than ultra-supercritical coal plant due to the water needs of the gasification plant, its auxiliaries and the gas turbine.

With net HHV efficiencies similar to ultra-supercritical coal, the CO_2 emissions rate is also similar (without CO_2 capture and storage (CCS)):

	IGCC
Thermal efficiency (HHV sent out)	40 – 42 %
CO_2 emissions intensity (kg/MWh(SO))	785 – 820

Assuming that CCS technologies can achieve an 88% reduction (US DOE-NETL, 2007) the CO_2 emission rate would be reduced to between 96 kg/MWh and 101 kg/MWh sent out.

By-products from the coal gasification process include:

- Inert glassy slag that has the potential to be utilised in road construction, ceramic production, concrete, mortar and mine rehabilitation,
- Fly ash or dry bottom ash which may be saleable to the cement or concrete industry or used in mine rehabilitation,
- Pure sulphur from the gas clean up system which can be sold.

IGCC has also currently a significant advantage over traditional pulverised coal technologies for CO_2 capture due to the lower level of pollutants in the syngas, higher proportion of CO_2 in the syngas and higher operating pressures. This bodes well for retrofits and new plant incorporating CO_2 capture. This is discussed further in Chapter 5.

3.3.4 Financial Factors

The construction cost of coal fired IGCC plants has to date been higher than that of supercritical pulverised coal technology and is one of the main reasons for the stall in technology implementation for coal based feedstock. It seems the only exception at the present time for commercial take-up is with the utilisation of low or negative cost fuels as feed such as petroleum residues, biomass waste, municipal waste or low rank coal, which can offset the higher construction cost of the IGCC plant.

Unit costs for syngas can also be reduced in a co-production arrangement where a combination of power, steam and syngas for H_2 or chemicals are produced. As sulphur removal is an integral part of the IGCC process, it also tends to be more attractive in markets where flue gas desulphurisation (FGD) is required.

There is a large variation in construction cost estimates for IGCC reported in the literature. Table 3.10 provides cost estimates from a number of sources.

Source	Construction cost ($A/kW)
Dalton *et al* (2007)	$2130*, $3250#
Topper (2006)	$1720#
Wibberley *et al* 2006	$1840
USEPA (2006)	$2170
Thambimuthu (2006)	$1880* - $2110#
Coca (2003)	$1860 - $2330

Table 3.10 IGCC Construction costs (# dry feed, * slurry feed)

With the exception of Wibberley, all were reported in $US or Euros, and have been directly converted using the exchange rates provided in section 2.3.5. There is therefore some uncertainty involved in this conversion as no attempt has been made to estimate and correct for local and overseas materials and labour components.

However, based on the above data and Connell Wagner experience with recent cost escalation of the construction of coal fired plant, the construction cost for an IGCC plant without CO_2 capture based in NSW on a greenfield site and within 4 hrs of Sydney was estimated. The cost is expected to range between $2,100/kW and $2,600/kW (±30%) in 2007 Australian dollars.

Connell Wagner estimated operating costs for 500MW to 1000MW IGCC sizes, are summarised in Table 3.11. The assumptions made in the estimation of the values presented include:

- Fixed O&M costs cover insurance, staff, contracts, overheads, licence fees and contract scheduled maintenance
- Other variable costs including spare parts and maintenance, consumables such as chemicals, oils and fluxes, water make-up and slag/ash disposal.

Coal ($/MWh(SO))	8.6 – 13.9
Variable O&M (excluding coal) ($/MWh(SO))	4.0
Fixed O&M ($/MW/yr)	40,000

Table 3.11 Estimated IGCC Operating and Maintenance Costs

The main project delivery risks include:

– Project bankability due to the relatively small number of operating plants and high construction and therefore financing costs,
– Procurement and project management/engineering strategy needs to target effective management of system integration and interfaces between major plant components,
– In the long term (beyond 2020) unsuccessful IGCC research and development programs to prove commercial operation of CO_2 capture and sequestration and hydrogen utilisation in fuel cells, gas turbines, transport liquids and chemicals.

3.3.5 Suitability for base load in NSW

Integrated gasification combined cycle technology (IGCC) is well suited to base load generation. However due to higher construction costs and lower system technology maturity IGCC is yet able to provide a bankable solution for large unit sizes and high rank coal as fuel. In the medium term (plant commissioned 2015-2020) this situation may change with the increasing current focus on economic drivers for environmental change, further technological advancements and industry utilisation of system components. In the long term the take-up of IGCC looks promising as a coal based technology that is capable of high efficiency, near zero emissions with carbon capture and sequestration and co-production of hydrogen for a wide range of applications.

3.4 Ultra Clean Coal Combined Cycle Gas Turbine

3.4.1 Description

This technology involves the use of a coal derived fuel (ultra-clean coal) in a Combined Cycle Gas Turbine plant. Ultra-Clean–Coal (or UCC) is a product produced from thermal coal feedstock that is very low in mineral matter and claimed to be a suitable fuel for use directly in Combined Cycle Gas Turbine power plants. The production of UCC involves a chemical process to remove mineral matter and alkalis from the coal.

3.4.2 Performance

The coal feedstock for conversion to UCC is claimed to be any thermal black coal (Cottrell *et al* , 2004). However as the technology is still at the demonstration stage there has been limited testing of feedstocks.

It is understood that purpose built gas turbines may be required to allow the utilisation of a solid fuel. Work conducted jointly by UCC Pty Ltd and the Centre for Coal Utilisation, Japan (Sasahara *et al*, 2002) is widely cited and describes testing conducted in Japan using UCC as a feed to a solid fuelled gas turbine. The combustion trials on a Mitsubishi Heavy Industries (MHI) 501G were considered to be successful as performance was satisfactory and no blade erosion was detected. However blade ash deposition and high combustor temperatures were of concern. It was reported (USDOE, 2005) that a further demonstration with an 18 month trial on a 6 – 15MW gas turbine is planned for 2008.

Therefore until a full scale demonstration is conducted the reliability and availability of the technology for base load power generation is not known

3.4.3 Environmental

The greenhouse gas performance of UCC is directly related to the technology or process in which it is utilised. However there is a CO_2 emissions penalty associated with the production of the UCC. Therefore, even though Combined Cycle Gas Turbine plants may offer thermal efficiencies in excess of 50%, a life cycle analysis of emissions may not necessarily show a benefit over conventional technologies.

Using the CO_2 emissions values presented by Cottrell *et al* (2004) for the production of UCC, the CO_2 equivalent emission per tonne of UCC production could be calculated. The values obtained were:

	kg CO_2 / kg fuel production	kg CO_2 / MJ fuel production
Wet UCC product	0.46	0.019
Dry UCC product	0.86	0.027

The overall greenhouse performance of UCC in different utilisation technologies could then be compared.

Calculations were performed using the above data for CO_2 emissions from UCC production, along with typical efficiency values for current Combined Cycle Gas Turbine plants. The results are compared in Table 3.12. Combined Cycle Gas Turbine thermal efficiency is very site dependent due to the sensitivity to ambient conditions.

A review of the thermal efficiencies of currently available Combined Cycle Gas Turbine plant found that the Alstom GT26B is capable of 48.6% efficiency (HHV basis) when firing fuel oil. A fuel oil efficiency has been considered as UCC would be more like oil than gas in terms of its chemical composition. The GE 9351F in combined cycle mode on fuel oil has an efficiency of around 51.3% (HHV). Therefore for this analysis, the base Combined Cycle Gas Turbine (CCGT) thermal efficiency has been assumed to be 50%.

Capacity	(MW)	1000	
Assumed Fuel		wet UCC	dry UCC
Coal SE	MJ/kg	24.4	32.5
Annual coal consumption	t	1,950,000	1,460,000
CO_2 emissions intensity (power station only)	kg CO_2/ MWh	635	634
CO_2 emissions intensity (including UCC production)	kg CO_2/ MWh	770	825

Table 3.12 Estimated Greenhouse Gas Intensity for UCC Fuelled Combined Cycle Gas Turbine Plant

For use in CCGT plant, the dry UCC product does not offer any greenhouse benefit over the wet case. This is due to the energy (and therefore CO_2) penalty associated with drying the UCC product.

Cottrell *et al* (2004) presented comparative water consumption values on a life cycle basis for UCC-CCGT and supercritical PF. The values quoted by Cottrell suggest that water consumption of UCC-CCGT is more than 4 times greater on a tonnes / MWh basis than a supercritical PF plant. As CCGT plants have inherently lower water consumption than conventional thermal plants, the water consumption for the production of UCC must be very high.

Reported values of NOx emissions for UCC – CCGT plants are not available. However it is expected that values would be as good as a gas turbine fired on fuel oil.

Based on the process chemical inputs of sodium hydroxide, lime and sulphuric acid, it may be expected that the waste stream could contain traces of unreacted chemicals along with the reacted coal minerals. The flowsheet provided in Cottrell *et al* (2004) indicates two by-product streams. The first is the by-product of the caustic digestion process and is predominantly sodium silicates. Sodium silicate is a soluble compound that is used in food preservation, concrete waterproofing and in refractory applications. The second by-product stream results from the sulphuric acid addition and is mainly aluminium sulphate and silicic acid. Aluminium sulphate is an industrial chemical that is widely used for water treatment applications.

3.4.4 Financial Factors

Provided that gas turbines become commercially available to handle the solid fuel, many of the financial factors for UCC – CCGT will be the same as for natural gas combined cycle plant. UCC production costs were reported by Cottrell *et al* (2004) and are summarised below. They are based on $A1.6/GJ fuel feed:

Fuel	Cost $/GJ
UCC (wet)	3.33
UCC (dry)	3.45

Using the fuel cost range assumed for this study, the expected cost of the wet UCC product would be $2.7 to $3.3 / GJ. This compares to the assumed price range for natural gas of approximately $4/GJ for natural gas.

Project delivery risks for UCC – CCGT are considered to be high due to:

- No experience with UCC product production in quantities suitable for base load generation.
- No experience with long term operation of a gas turbine on UCC fuel.
- Waste disposal costs are not known, but are expected to be significant.

3.4.5 Suitability for base load in NSW

Although the price of UCC fuel appears to be competitive with natural gas, it is not expected that UCC – CCGT technology will be suitable for specifying for base load power generation in NSW within the next 10 years. This is due to:

- The very high project delivery risks
- A commercial high efficiency gas turbine capable of using UCC is yet to have been developed
- The high water consumption of UCC would either detract from its environmental credentials or impact on its economic competitiveness.
- Based on publicly available information, from a life cycle greenhouse gas intensity perspective, UCC offers no present benefit over supercritical PF technology.

3.5 Co-Utilisation of Coal with Gas

3.5.1 Description

Reducing greenhouse gas emissions can be achieved by using coal with other fuels, for example co-firing coal with gas, or biomass. The lower CO_2 emission factor for natural gas compared to coal brings a substantial reduction in overall CO_2 emissions when natural gas is partially substituted for coal. Co-firing natural gas with coal in future coal-fired power stations may present a useful measure to meet the emission target, especially if waste coal seam methane is used.

The following is a brief review of various gas co-firing technologies in terms of their theoretical basis, practical applications, economics and environmental benefits (Gurba, 2007), (Gurba & Van Schagen, 2004).

3.5.2 Co-utilisation of Coal Seam Methane in Existing Coal-fired Power Plants

The availability of cheap coal, the large existing coal-fired generating capacity and the increasing reserves of natural gas, make co-utilisation of natural gas and coal an attractive option to achieve the required capacity increase with a simultaneous decrease of specific greenhouse gas emissions. Based on the Australian Bureau of Agriculture and Resource Economics' projections the market share for natural gas increases significantly from 13% in 2000 to 23% in 2020 (Dickson *et al* , 2003). The presence of substantial amounts of natural gas in the form of coal seam methane in Queensland and New South Wales makes co-utilisation in these states very attractive because many coal-fired installations are located on or near the coal seams. The advantages for a power plant able to fire both coal (80-90%) and gas (10-20%) include greater fuel flexibility, less environmental emissions and increased capability and efficiency of the plant.

The CCSD report (Andries, J and Stubington, J. 2004) focuses on the technological factors influencing the viability of co-utilisation of natural gas in existing coal fired installations. Co-utilisation in existing coal-fired power generation systems can be realised by direct injection of natural gas in the coal-fired boiler (co-firing and reburning) or by integrating a natural gas-fired combustion turbine into an existing coal-fired installation (repowering, retrofitting, refurbishing) and keeping parts of the existing coal-fired installation (especially the steam turbine) in operation. Repowering can significantly increase the efficiency and the capacity of the installation.

Co-firing of natural gas leads to decreased coal input, however the main incentives for this technology in Australia, such as fuel flexibility and decreased SOx emissions, are not very strong. Reburning leads to decreased coal input and decreased SOx and NOx emissions. The availability of low-sulphur coal and relatively high NOx emission limits, make this a less attractive option in Australia.

Parallel repowering is an attractive solution when the steam turbine has sufficient spare capacity. It results in increased capacity and efficiency, while using the same amount of coal. Two options for parallel repowering are feed water heater repowering and hot wind-box repowering:

– Feed water heater repowering (FWHR) is the most attractive co-utilisation technology as it provides increased capacity and efficiency, while utilising the same amount of coal. It enables very flexible operation (the steam turbine system and the combustion turbine system can be operated separately).
– Hot - windbox repowering also results in increased capacity and efficiency while using less coal. However it is expected to have a higher construction cost than FWHR.

Further detailed studies are needed to provide reliable data for economic (least cost analysis) and environmental assessment (life cycle analysis) of the technology options for gas utilisation in existing coal-fired installations (Gurba, 2007).

3.6 Nuclear Power

3.6.1 Description

Nuclear power generation involves utilising the heat from a controlled nuclear fission reaction. The heat is used to produce steam and therewith drive a steam turbo generator in an analogous manner to other thermal generation technologies. The nuclear electricity generation process is illustrated below.

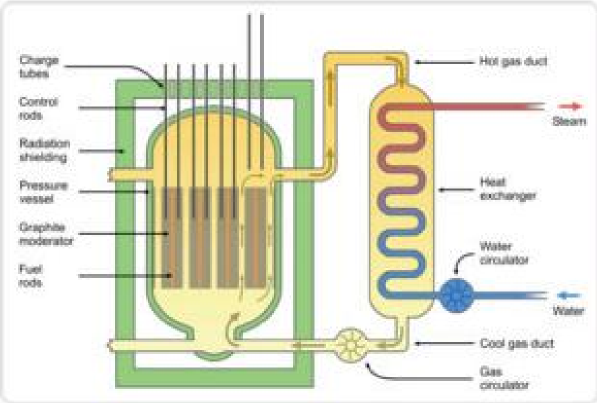

Figure 3.3 Schematic of a Nuclear Plant

Isotopes that can be used for fuel are said to be fissile i.e. able to capture neutrons and split into fragments, thus releasing energy. There are three nuclei that can participate in a self sustaining chain reaction. Naturally occurring uranium is a combination of two isotopes, ^{238}U (99.3%) and fissile ^{235}U (0.7%). The only two other (artificially produced) fissile isotopes are ^{233}U (artificially produced by bombarding ^{232}Th with neutrons) and ^{239}Pu (artificially produced by bombarding ^{238}U with neutrons)[1].

There are three generic types of nuclear reactor:
– Natural uranium reactors,
– Enriched uranium reactors and the
– Breeder reactors.

The natural reactors can use the natural ratio of ^{238}U and ^{235}U, enriched uranium reactors use a higher concentration of around 4 to 5% ^{235}U. Breeder reactors use a mixture of uranium and plutonium oxides but are not normally used for power generation purposes. Breeder reactors convert non fissile ^{238}U to ^{239}Pu.

To create a sustainable reaction, the nuclear fuel is embedded in a moderator, the purpose of which is to slow down neutrons which are a by product of the reaction so that they in turn cause other ^{235}U nuclei to undergo fission. There are three types of moderators used in nuclear power reactors: graphite, water and heavy water. Deuterium is a stable isotope of hydrogen (approximately twice the mass of Hydrogen) and forms the basis of heavy water. Heavy water is 10% heavier than ordinary (light) water and has a neutron moderating ratio 80 times that of light water (Wibberley *et al* , 2006)

Nuclear power plant reactor types in service include the pressurised water reactor, boiling water reactor (BWR), gas-cooled reactor (Magnox and AGR), pressurised heavy water reactor “CANDU” (PHWR), light water graphite reactor (RBMK) and fast neutron reactor (FBR) which are cooled and moderated by different media. (Wibberley *et al* , 2006)

The most common reactor designs used for power production are based on two US light water designs:
– Pressurised Water Reactor (60%)
– Boiling Water Reactor (21%) (Hore-Lacy, I, 2000)

The pressurised heavy water reactor (PWHR) accounts for 8% of the world's reactors. First generation reactors were first built in the 1950s with the second generation being built mostly in the 1970s.

Pressurised Water Reactor (PWR) (Wibberley *et al* , 2006)

Pressurised Water Reactors use ordinary water (light water) as coolant and moderator in the reactor core. The Primary coolant loop is pressurised to around 16MPa to prevent boiling of the reactor coolant and is heated to around 320°C to 330°C by the fission process as it passes through the core. Energy is transferred from the primary loop to a secondary loop. This energy transfer produces steam which drives a steam turbine, producing power though the generator. The overall steam cycle is around 33 % efficient. Currently, evolutionary third generation PWRs have been developed in Korea and Japan and are scheduled for new build there. Generation 3+ designs are being developed presently and they incorporate improved safety features, better fuel utilisation, improved efficiency and other features for improved economics.

Boiling Water Reactors (BWR) (Wibberley *et al* , 2006)

Boiling water reactors use ordinary water as the coolant and the moderator. Water is constantly fed into the bottom of the primary vessel and boils in the upper part of the reactor core. The BWR is different from the PWR in that the steam generated at a pressure of 7 MPa and temperature around 290˚C, is routed directly to the turbine and not to an intermediate heat exchanger. Fuel load and efficiency are similar to the PWR.

The BWR design does not require separate steam generators and has reduced reactor vessel wall thickness and material costs owing to its lower primary pressure. However, the BWR primary circuit includes the turbines and pipework and these components become radioactive through exposure to small quantities of activated corrosion products and dissolved gases over the lifetime of the reactor. This complicates plant maintenance and increases the costs of decommissioning. The reduced power density means that for a given power output a BWR unit is significantly larger than a similar PWR unit.

The third generation BWR, the Advanced BWR (ABWR), developed in the 1990s, is claimed by the manufacturers to have improved economics, passive safety features, better fuel utilisation and reduced waste.

A Generation III+ BWR has been proposed in Europe by Areva. The design is an evolution of the German Siemens-designed BWRs that have been in operation for more than 20 years and use a combination of proven components, additional passive safety features, an increase in fuel enrichment to 5 per cent while reducing construction and operating costs.

Pressurised Heavy Water Reactor (PHWR/CANDU) (Wibberley *et al* , 2006)

The Pressurised Heavy Water Reactor or the CANDU Reactor (CANada Deuterium[100] Uranium reactor) was developed by the Canadians in the 1950s and are fuelled with natural uranium. The PHWR/CANDU design is similar to the PWR design in that the fission reaction heats pressurised coolant in the Primary loop. The PHWR/CANDU reactor uses pressurised heavy water in the primary loop to prevent boiling and steam formation. Energy is transferred to the secondary loop where steam is produced. This steam then drives the turbine and in turn the generator, producing electricity. The overall steam cycle is 31% efficient.

The CANDU reactor differs from the PWR design in that while the PWR core and moderator is contained in a single pressure vessel, the CANDU fuel bundles and coolant are contained in hundreds of pressure tubes penetrating a large tank of heavy water moderator. These pressure tube reactors are inherently safer than the PWR and BWR as they do not have the possibility of a single point of failure of the large pressure vessel.

The CANDU reactor is designed to use natural uranium dioxide containing ^{235}U. The use of natural uranium removes the reliance on international and potentially expensive enriched fuel. The increased cost of the heavy water moderator and the faster consumption of the fuel partially negates the use of natural uranium.

The CANDU reactor can also be refuelled while online and at full power. Approximately one third of the fuel load of the Pressurised Water Reactors and Boiling Water Reactors is batch refuelled every 18 to 24 months during a 30 to 60 day shutdown. In spite of the improvement to availability, capacity factor and economic performance by the CANDU Reactor not requiring periodic refuelling, the PWRs and BWRs have reduced their refuelling time and have improved to similar or better performance.

Proliferation concerns exist due to the ease with which nuclear fuel may be removed from the CANDU Reactor.

3.6.2 Availability and maturity of technology

Nuclear power is an established and proven technology and has been in use since the 1950s with the first civilian nuclear reactor in operation in 1955 (UMPNER, 2006). In 1999 Nuclear Power generation contributed 16% of the world's base load electricity production with a total installed nuclear capacity of 365 GW from 434 nuclear units (Hore-Lacy, 2000).

The time for establishing a nuclear regulatory framework and planning, building and commissioning a nuclear power plant is expected to be between 10 to 20 years for the first power plant. (UMPNER, 2006). The time for constructing and commissioning a nuclear power plant is expected to be more than 4 years (EPRI, 2006b).

3.6.3 Reliability Performance

The North American Reliability Council's *Generating Availability Report* (NERC, 2006) was utilised to identify the availability performance of nuclear power stations relative to other fossil fired stations. The database was selected because of the large population of operating units and because there is no similar Australian database available. The database represents 74% of the installed generating capacity in the United States and Canada.

The Equivalent Availability Factor (EAF) for the group "Fossil Power stations of all types in the size range 600 to 799MW" was 83.38% with an Equivalent Forced Outage Rate (EFOR) of 7.27% for the period 2001 to 2005. The Equivalent Availability Factor (EAF) for the group "Nuclear Power stations of all types in the size range 1000MW+ was 88.21% with an Equivalent Forced Outage Rate (EFOR) 3.69% for the period 2001 to 2005. The availability of the nuclear stations is higher than that of the fossil power stations. The largest capacity loss due to planned and forced outages of a nuclear unit is for refuelling.

3.6.4 Environmental

Nuclear power stations need more cooling water than fossil fired power stations as they operate at lower pressures and temperatures and as a consequence have a lower thermal efficiency and therefore reject more heat and require more water for cooling. Typical make-up water requirements are presented below (UMPNER, 2006b):

Plant and Cooling System Type	Typical water consumption (kg/MWh(SO))
Nuclear steam, once through cooling	~1,500
Nuclear steam, pond cooling	1,100 to 1,850
Nuclear steam, cooling towers	~1,850

Nuclear power stations may be sited far from the fuel source or waste disposal site. This would allow the siting of a nuclear plant near the ocean or large bodies of water.

Nuclear power is a low greenhouse gas emission technology (UMPNER, 2006). Nuclear generating plant however does not generate greenhouse gases directly as do fossil fired generating plant. Greenhouse gases are generated during the nuclear fuel cycle. Emissions arise from the mining process, fuel enrichment, power station construction, spent fuel and waste disposal and decommissioning. A study commissioned by the UMPNER Taskforce (2006) and carried out by the University of Sydney into potential life cycle emissions of nuclear power in Australia estimated the nuclear life cycle emissions intensity to be between 10 and 130kg CO_2 -e/MWh(SO). The range in life cycle emissions is due to the energy intensity of the enrichment process used. The best estimate for the life cycle greenhouse gas emissions is 60 kg CO_2-e/MWh(SO).

A study into the estimated relative levels of life cycle SO_x and NO_x emissions from nuclear, fossil fuel and wind generation technologies was carried out by the Australian Coal Association and reported by (UMPNER, 2006). The study revealed that nuclear technology produced about 10% of the NO_x emissions of coal and gas based electricity production. The study also found that SO_x emissions from nuclear technology was about 5% of that of coal based technology.

3.6.5 Health and Safety

Ionising radiation and its health impacts are well understood and there exist well established safety standards. Modern operating methods and safety requirements reduce the risk posed by nuclear reactors and the mining of uranium. The health and safety performance of nuclear power stations has improved significantly over time and is expected to improve even further with new generation reactors.

The report *"Uranium Mining, Processing and Nuclear Energy"* concludes that "nuclear power has fewer health and safety impacts than current technology fossil fuel based generation and hydro power, but no technology is risk free" (UMPNER, 2006). Mathematical and statistical modelling indicates that the risk of a nuclear incident where there is a significant contribution to background radiation is very low. The vendors of the new reactor designs have improved the safety of the designs of the present generation of reactors and it is expected will improve that of the next generation of reactors.

Public perception of the risk (probability and the consequence) of a nuclear reactor incident is likely to be much greater than the actual risk. The public may not want to voluntarily subject themselves or future generations to a higher perceived risk although there may be many benefits to the introduction of the technology.

Radioactive waste and spent fuel arising from nuclear power generation has to be managed. Management includes the handling, treatment, conditioning, transport and disposal of the radioactive material (UMPNER, 2006). Radioactive materials have been safely managed for decades.

The radioactive material may be classified as low-level waste, intermediate-level waste and high level waste (HLW). High level waste is self-heating due to radioactive decay. Spent fuel is stored in a reactor cooling pond to allow reduction in residual heat so that the material may be handled. The material is then stored away from the reactor before reprocessing and disposal.

Although no country has implemented permanent underground disposal, there is scientific and technical consensus that HLW may be stored underground in stable geological structures. Some countries are proceeding with the design and development of deep geological repositories.

The IAEA cites the following as possible terrorist scenarios in relation to nuclear material

- Theft of a nuclear weapon
- Theft of a nuclear or radiological material
- Sabotage

The theft of Uranium ore is a relatively low security concern due to the low levels of fissile ^{235}U.

The consequences of terrorist acts of sabotage on the facilities used for mining, conversion, enrichment and fuel fabrication are likely to be lower than that on industrial facilities that would likely contain higher quantities of hazardous materials. The theft of spent fuel and the breaching of spent fuel containers is considered to be a low risk. Nuclear reactors protection against terrorist threats will be improved by stringent security measures.

3.6.6 Financial Factors

The UMPNER Taskforce (2006) commissioned the Electric Power Research Institute to examine recent studies that compare the costs of generating electricity using different technologies including nuclear energy.

The studies all used levelised cost of electricity (LCOE) estimates to calculate a comparable cost for each technology option. The LCOE is the constant real wholesale price of electricity that recoups owners' and investors' capital, operating and fuel costs including income taxes and associated cash flow constraints. The EPRI study shows that there is a large range in the LCOE estimates. This large range is due to the different assumptions and inputs used in calculations. Factors that have a large influence on the LCOE are the discount rate and the risk due to 'First Of A Kind' (FOAK) costs made by the studies.

A nuclear power plant in Australia is likely to be 10 to 15% more expensive in Australia because Australia has neither nuclear power plant construction experience or a nuclear regulatory infrastructure. The 'settled down costs' i.e. not FOAK in Australia for the first nuclear plant is estimated to be around A$44 to 70/MWh(SO) if the investor perception of commercial risk is similar to that of other base load technologies (UMPNER, 2006)

The parameters used by Professor Gittus (2006) in his Financial Model are detailed below as they should be a fair representation of the cost s of nuclear power. The investment cost for a nuclear power station was estimated at A$ 2,850/kWe. The annual fixed operation and maintenance cost was estimated at 1.5% of the investment cost per year. The annual variable operation and maintenance cost was estimated at A$5.55/MW. Fuel costs for electricity production are estimated to be A$4.65/MWh(SO) (Gittus, 2006)

Although the technology is mature, the first nuclear plant built in Australia may be subjected to a number of project delivery risks (Gittus, 2006):

- Risk that the Australian Safety Regulator will delay licensing the Plant and will require costly design changes
- Risk that the Australian Safety regulator will introduce delays to other Consents and in this way delay the construction of the station.

3.6.7 Suitability for base load in NSW

Based on the foregoing discussion it is concluded that nuclear power is suitable for base load electricity supply in NSW, but the time required to implement a regulatory regime and construct a plant would preclude its use for the next base load plant in NSW.

4. Renewable Generation Technologies

This section of the report is related to the production of electricity from renewable energy resources. It discusses technologies that can convert renewable energy into electricity and that may be considered as an option for base load electricity generation.

The objective of this report is to assess technologies that can convert renewable energy into electricity and supply new base and intermediate load electricity capacity in NSW by about 2014. Accordingly, the section is structured to initially consider a broad range of renewable technologies, which are then filtered to only consider the ones with better potential to supply bulk electricity to meet the base load demand within the required timeframe.

4.1 Renewable Energy

Renewable energy resources by definition are those that are not depleted by their use. In the context of this report, renewable energy also includes energy resources that are naturally occurring, have no associated greenhouse gas emissions and are considered as renewable, as the rate of use would not significantly impact on the resource, even over a long period of time.

The renewable energy resources are generally considered to be the following:

- Hydro
- Ocean: wave and tidal
- Wind
- Solar
- Geothermal – hydrothermal – Hot Dry Rocks
- Biomass (typically waste from an agricultural activity or the production of an agricultural product and also including energy crops)
- Biomass: Methane gas from the biomass components of sewage or municipal solid waste

There are a very large number of different technologies available to convert renewable energy resources to electricity while there are other technologies to convert the renewable energy resource into a fuel that may be able to be used for electricity production. This report only considers the technologies that use renewable energy to produce electricity directly.

4.2 Electricity Generation in the National Electricity Market (NEM) and Renewable Policy Measures

Producing electricity from renewable energy resources has a significant advantage, in that the marginal cost of electricity is zero in most cases reflecting the nature of the energy resource. Consequently electricity produced from renewable resources can be bid into the electricity market at effectively zero cost, which would be less than the lowest marginal price of any coal fired plant. However, a proponent for a renewable project must also be able to obtain a secure return on the investment, which would not be viable by just taking the electricity pool price. Consequently an agreement for the sale of the electricity and the renewable energy certificates may be required to provide the security necessary to facilitate the financing arrangements prior to financial close.

In Australia renewable projects, except for many of the existing hydro projects, have generally been supported by policy measures such as the Mandatory Renewable Energy Target implemented by the Commonwealth Government. In the future renewable energy measures would still be required to support the development of renewable technologies. These will include those enacted by the States, such as the NSW Renewable Energy Target (NRET) and similar measures in Victoria and South Australia, or possibly a revised MRET. With these measures in place the necessary demand for electricity from renewable resources can be achieved to support the development of new projects.

It is likely that given similar penalties and incentives to the current MRET policy measure the quantity of renewable energy and proportion of generation in the NEM will achieve the target of the State's renewable measures. Consequently there will be a significant amount of electricity produced by renewable energy in the future. The assessment of this impact is beyond the scope of this report. However the quantity of electricity produced from renewables has implications for the nature and mix of the remainder of the plant operating in the system. These are potentially as follows:

– They will displace the existing plant supplying base load as their marginal price is lower.
– Depending on the nature of the renewable source they may not necessarily contribute to the peak load when it occurs and additional reserve plant is likely to be necessary.
– Renewable plant may need to be constrained at times so that the amount of change that can occur, due to a sudden change in the renewable energy supply rate, is within the limits of the system to respond. Alternatively, additional reserve plant may be required.
– Much of the renewable plant could be located outside of NSW and during peak times could be constrained by the interconnectors or other network constraints and would not contribute to meeting the NSW peak demand. This then means that local plant to meet the requirement will be necessary.

In the context of new base load capacity, renewable technologies will tend to be dispatched before other plant once they are installed. However to meet the intent of base load supply they will need to provide significant energy (MWh) into the system on demand and at a reasonable overall cost. Although policy measures such as emissions trading will tend to change the relative merit of one technology compared to another the assessment of the impact of such measures is beyond the scope of this study. Furthermore, although appropriate measures will drive the development of renewable technologies, the commercialisation and cost reduction process takes time and in the short term particular technologies would be unlikely to deliver significant base load capacity unless they are already well positioned to do so.

The implication is that any technology must be commercially viable now, as if it is not commercially viable now it is not likely to be viable within the next five years, given the long development time for new technologies. The typical development time from invention to 50% of market could be 10 to 30 years (ID Gielen, 2007).

4.3 Electricity Generating Technologies for Renewable Energy

This section identifies the technologies with potential as base load electricity supply. As noted previously most renewable technologies, once installed will provide base load supply as they have the lowest marginal cost. However to meet the demand for bulk electricity other requirements must also be met.

The major technologies for converting renewable energy into electricity are listed in Table 4.1 with their current status. Where the status is such that there is an overriding reason why a technology is not likely to be a contender for base load supply in the next 3 to 4 years then the cost becomes irrelevant.

Resource	Technology	Status
Hydro	Hydro electric turbine generators	Hydro is a mature technology with the cost highly dependent on the local factors. However, the lack of any significant additional water resources that could be utilised for hydro generation is the main issue for NSW. This is demonstrated by the low level of development over the past forty years (see Figure 4.1) indicating that the bulk of hydro resources have already been exploited.
	Mini Hydro	Mini hydro is also a mature technology but due to the nature of the technology and for the same water resource reasons as large hydro systems it is unlikely to be able to provide any significant generating capacity.
Ocean	Wave and Tidal	The technology for generating electricity from waves and the tide is in its infancy (MMA 2006). At present there is one wave demonstration plant in NSW. Given the development status of wave and tidal power it is unlikely to be viable for the next generation of base load capacity in NSW.
Wind	Wind Turbines	Wind turbines are a mature technology with the operating and maintenance costs well understood. There are currently 4 wind generation sites in NSW, the largest of 10 MW capacity at Blayney. Wind turbines are of the lowest cost renewable generating technologies. The intermittent nature of the output of wind turbines is an issue that requires management from the network operator.
Solar - PV	Solar Photovoltaic	Solar PV technology is ideal for decentralised electricity production through installation on individual residences or in community groups. The technology, although mature in the sense that it is mass produced, is still undergoing significant research to improve performance and in particular to reduce costs. It is being adopted through market drivers and financial support but without this support would mainly be used in niche applications. The construction cost of a 1 kW peak PV system is in the order of $12,000 (MMA 2006) and produces approximately 1500 kWh/annum in Sydney (Lawley 2003). The cost of electricity from PVs is estimated at $250 to $400/MWh (URS 2006).
Solar - Thermal	Trough concentrators	Solar thermal uses direct sunlight that is concentrated to provide higher energy density. Solar thermal has the advantage that the heat produced can be stored for recovery at a later time and that it uses what is essentially a conventional power cycle. Solar trough concentrators have been operating in the USA since 1984 (Philibert 2004) with a recent installation in 2007. Solar resources in NSW have the potential to provide significant electricity supply if the costs can be reduced.

Resource	Technology	Status
Geothermal - hydrothermal	Steam turbine generators or binary cycle	Hydrothermal is heat accessed through a water media and uses conventional power cycles. The resource is usually associated with geothermal activity, eg New Zealand and the USA. Hydrothermal resources are only used to a small amount in Australia. They would not be a candidate for base load electricity supply due to the lack of a known suitable resource.
Geothermal – Hot Dry Rocks	HDR heat exchanger with binary cycle	There is significant interest in Hot Dry Rocks in South Australia at the present time. It may have the potential to produce a significant quantity of electricity at a reasonable price. Hot Dry Rock resources use a similar technology to that used for hydrothermal. No electricity to date has been produced in any location. However the individual technologies required are to a large extent proven.
Biomass - combustion	Steam turbine generators	This technology is mature.
Biomass gasification	Gasifier	This technology coverts the biomass into a combustible gas that may be used as a fuel. However for the purpose of this study, the resource is more of an issue than the technology and this will be covered under biomass combustion.
Biomass – methane	Gas engine	Gas engines are mature technology. However, the production of methane from landfill waste and similar sources is limited and would not provide the energy requirements for base load supply.

Table 4.1 Status of Electricity Generating Technologies for Renewable Energy

Table 4.2 is an extension of Table 4.1 and lists the most common renewable technologies with the intent of assessing the technologies that should be considered further in the context of this report. Most of the terms in Table 4.2 are self evident, except that the Potential for Base load in NSW refers to the overall potential for further consideration in this report. The definition of the level of maturity has been explained in Section 2.3.7.

Resource	Technology	Level of Maturity	Commercial by 2010	Potential for Base load in NSW
Hydro	Hydro electric turbine generators	Mature	Yes	Yes, but only minimal potential for additional in NSW (see Section 4.4)
	Mini Hydro	Mature	Yes	No - resource too small
Ocean	Wave	Demonstration	No	No - Immature
	Tidal	Demonstration	Yes	No - siting in NSW
Wind	Wind Turbines	Mature	Yes	Yes - but only some capacity can be considered firm (see Section 4.5)

Resource	Technology	Level of Maturity	Commercial by 2010	Potential for Base load in NSW
Solar - PV	Photovoltaics	Mature	Yes	No - too costly at present
Solar - Thermal	Trough concentrators	Economically feasible under certain conditions	No	Yes (see Section 4.6)
Geothermal - hydrothermal	Steam turbine generators of binary cycle	Mature	Yes	No – limited resources in NSW
Geothermal – Hot Dry Rocks	HDR heat exchanger with binary cycle	Research	No	No - no full system demonstration plant (see Section 4.7)
Biomass - combustion	Steam turbine generators	Mature	Yes	Yes (see Section 4.8)
Biomass gasification	Gasifier	Demonstration for plant suitable for base load	No	No – as well biomass use is a resourcing issue and is the same for biomass combustion
Biomass – methane	Gas engine	Mature	Yes	No Resource is relatively small and it would only make a small contribution to base load

Table 4.2 Renewable Energy Resources and Renewable Energy Electricity Generating Technologies

All of the technologies have the potential to supply some of the base load requirement as they have very low or essentially zero marginal cost once they are installed. Some of the technologies do not operate continuously and would require back-up plant in the base load role, which is likely to be peaking plant. Taking into account the time by which new base load plant may be required and considering the time that it takes for a technology to mature and provide electricity at a reasonable cost, the following will be considered in detail.

- Hydro
- Wind
- Solar Thermal
- Geothermal Hot Dry Rocks (due to its high potential)
- Biomass Combustion

4.4 Hydro

4.4.1 Description

Hydro generation is a mature technology with current installed capacity in NSW of over 4236 MW, primarily made up of 3756 MW in the Snowy Mountains Scheme. The remaining 480 MW of installed capacity in NSW is from around 30 hydro projects ranging in capacity from hydro projects in the mini-hydro range up to large hydro projects of around 240 MW. The current hydro projects in NSW are listed in Table 4.3 (RISE, 2007).

Station	State	Capacity MW	Operator	Operation Commenced
Tumut 3	NSW	1500	Snowy Hydro	1972
Murray 1	NSW	950	Snowy Hydro	1966
Murray 2	NSW	550	Snowy Hydro	1968
Tumut 1	NSW	329.6	Snowy Hydro	1959
Tumut 2	NSW	286.4	Snowy Hydro	1961
Shoalhaven	NSW	240	Eraring Energy	1977
Blowering	NSW	70	Snowy Hydro	1971
Guthega	NSW	60	Snowy Hydro	1955
Hume (NSW)	NSW	29	Eraring Energy	1957
Warragamba	NSW	50	Eraring Energy	1959
Copeton	NSW	24	Meridian Energy Australia	1996
Burrendong	NSW	14.5	Meridian Energy Australia	1996
Wyangla Dam	NSW	18	Hydro Power	1992
Burrinjuck II	NSW	16	Eraring Energy	2001
Burrinjuck I	NSW	12	Eraring Energy	1927
Other 24 stations (less than 10 MW each)	NSW	approx. 60		

Table 4.3 Main Hydro Power Stations in NSW and ACT

The potential for the development of economically viable small hydro projects on large dams in Australia is limited and the most attractive projects have been developed (Redding, 1999). This is also the case in NSW – it can be seen from Figure 4.1 below that the amount of hydro capacity that has been installed over the last 20-30 years is relatively small.

Most new hydro installations in that period have tended to be small and mini hydro schemes constructed on dam outlets to utilise increased environmental flow releases. It can be concluded that, in the absence of any large-scale water diversion schemes being developed in the future that could integrate hydro capacity, the opportunity for further development of hydro schemes in NSW is limited.

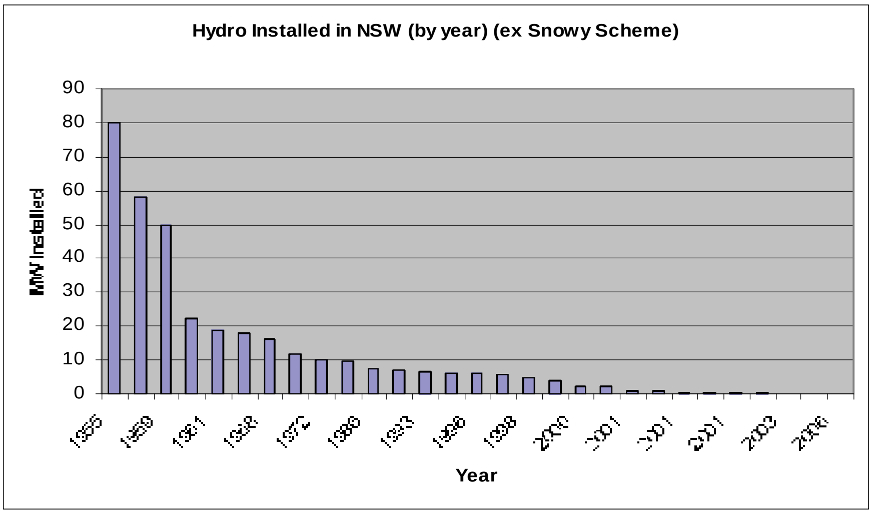

Figure 4.1 Hydro Installed in NSW per Year

In 1998 SEDA investigated the potential for hydro in NSW and the ACT. An extract from the investigation report as reported in the Redding Energy Report (Redding, 1999) is shown in Table 4.4.

Site	Capacity (kW)	Annual Generation (MWh(SO)/yr)	Approximate Construction Cost (,000)
Bendora	610	2100	1200
Berembed Weir	1620	6500	4000
Brogo	250	1200	790
Burrinjuck	5000	49000	18000
Cataract	380	3300	880
Chifley	330	1400	680
Clarrie Hall	650	2700	1200
Cochrane	2150	12500	2700
Copeton		700	1300
Cordeaux	300	2600	750
Eraring	7400	50000	8700
Euston	3400	15000	6200
Glennies Creek	580	1800	1000
Gogeldrie Weir	3100	9200	6000
Hay Weir	2600	7800	4700
Lostock	410	1400	1000
Mangrove Ck	710	1000	1100
Maude Weir	2200	4700	4800
Nepean	710	6100	1100
Pindari	2000	6700	2700
Redbank Weir	1800	3700	4100
Scrivener	1480	5200	2200
Split Rock	1300	4500	2100
Stevens Weir	600	2600	1900
Tallowa	5600	19500	7000

Site	Capacity (kW)	Annual Generation (MWh(SO)/yr)	Approximate Construction Cost (,000)
Toonumbar	370	1000	900
Torrumbarry	2780	16000	5000
Warragamba - Prospect Pipeline	4900	35000	6500
Windamere	300	1300	700
Yanco Weir	1400	2100	3600
Totals	54930	270000 (approx)	

Note: Some of the additional hydro noted in this 1999 report has been realised.

Table 4.4 Potential for Additional Hydro in NSW (Redding 1999)

The study showed that there was only around 50 MW of potential hydro capacity in NSW. With further investigation it is not expected that all the schemes identified would be found to be feasible. Also, some of these sites have been developed since the study. In general thee is only minimal potential for additional hydro generation in NSW.

4.4.2 Performance

Existing hydro projects are associated with dams and other infrastructure that have been primarily developed for water supply purposes with hydro generation being of secondary importance. As such, any hydro generation from these schemes is heavily dependent on water releases to meet irrigation, domestic or industrial water supply requirements.

The majority of the water releases are for irrigation purposes and are therefore highly seasonal. The resultant hydro generation is also therefore highly seasonal and cannot be regarded as base load power.

The magnitude of irrigation releases (and so the dependent hydro generation) are also highly variable and are determined on a year-by-year basis according to the water storage availability. In addition, the levels of water supply security applicable to most water supply schemes are lower than would normally apply to dedicated water supply schemes to base load power generation facilities. As a result, generation based on irrigation schemes can be severely curtailed by lack of water during drought periods.

Therefore, while hydro generation provides a useful contribution to power system supply when water is available the vulnerability to generation curtailment during droughts means that such hydro generation cannot be considered as providing reliable base load generation.

4.4.3 Environmental

Hydro generation is a renewable generation technology. However, the major issue related to hydro projects is the potential impacts of water use on the environment due to the retention of streamflows in water storages and the changes to streamflows below the dams.

There is an increasing awareness of the environmental impacts to riverine environments in Australia's major catchments. As a result, the rate of construction of new dams has slowed considerably in the last 20 years in the state and this trend is likely to continue.

4.4.4 Financial Factors

The table shows that approximately 50 MW of potential hydro projects were identified with a potential generation up to 27 GWh. The cost data indicate that the construction costs are very site-specific with a range of $25 - $282/MWh(SO) with construction cost ranging from $1200 - $2600/kW.

4.4.5 Suitability for Base load in NSW

The potential for further hydro development in the state to provide base load power is limited by the availability of water. As with most of the existing hydro capacity, any future capacity is likely to be dependent on the potential to be included in new or existing water supply schemes. Any such hydro generation is likely to be dependent on water released primarily to satisfy water supply requirements. It is considered that there is very limited capacity (less than 50MW) for further hydro generation that could be developed for base load generation.

4.5 Wind

4.5.1 Description

Wind power is a mature renewable technology with over 74,000MW installed and operating worldwide with over 15,000MW having been installed in 2006 alone. Germany (20,600MW), USA (11,700MW) and Spain (11,600MW) have the most installed capacity.

This increasing rate of wind power installation has resulted from increasing awareness worldwide of the need for sources of renewable electricity generation to reduce the global reliance on fossil fuelled energy production.

Existing installed wind power capacity in Australia is relatively modest. However, in recent years there has been significant growth from a low base in both installed capacity and the number of wind farm projects under development. The emergent Australian wind industry has primarily resulted from the Mandatory Renewable Energy Target Scheme (MRET) introduced by the Federal Government in 2000.

Wind farm development has been primarily concentrated in the southern states of Victoria, South Australia and Tasmania as well Western Australia. The status of wind farm development in Australia is summarised below:

Australia Wind Power Development Status:

Operating	817 MW
Under Construction(or construction imminent)	685 MW
Planning Approved	2325 MW
Other Identified	3775 MW

However, wind development in NSW has to date been limited by a poorer average wind resource, although a number of large wind farm projects have obtained planning approval. The status of wind farm development in NSW is summarised below:

NSW Wind Power Development Status:

Wind Farms and Status	Capacity
Wind Farms Operating	
Crookwell Wind Farm	5 MW
Blayney Wind Farm	10 MW
Total Operating (includes sites with less than 5 MW)	16.6 MW
Wind Farms Under Construction (or construction imminent)	0 MW
Wind Farms Planning Approved	
Crookwell II	92 MW
Cullerin Range	30 MW
Gunning	62 MW
Snowy Plains (Berridale)	30 MW
Taralga	105 MW
Capital (Bungendore)	132 MW
Conroys Gap (Yass)	30 MW
Total Approved (approximate)	480 MW
Other Identified	1165 MW (750 MW considered probable, and subject to obtaining PPAs)

(Note: based on projects listed on the Auswind website but noting that not all projects listed are likely to be economically feasible. Also, development of NSW wind projects will be in competition with wind farms in other states and other renewables under the NRET Scheme.)

4.5.2 Performance

The ability of wind generation to provide reliable base load generation is primarily constrained by the variability of the wind resource to produce consistent and stable wind farm output.

Typically, a wind turbine generates full rated power output at around 13m/s (47km/h) whereas wind farm feasibility would generally be based on average annual wind speeds of greater than 7.5m/s (27km/h). Therefore, most of the time a wind turbine would operate at less than its full rated power with a typical annual capacity factor of 30% - 35% in NSW.

The variability of the wind limits the ability of a particular wind farm to generate power as and when required for base load generation. However, a number of wind farms with sufficient geographical spread to be exposed to different wind regimes at any one point in time can provide a degree of "firm" power.

A study by CSIRO (Davy & Coppin, 2003) has concluded that wind generation spread across the NEM states of South Australia, Victoria, Tasmania, New South Wales and Queensland could theoretically provide firm power equivalent to around 10% of installed capacity (based on 95% confidence level and no network constraints such as state transmission interconnector limits). However, the level of "firm" power from wind generation confined solely to NSW only would not be as great because of increased correlation of these wind farms to similar wind regimes. It is estimated that "firm" power for wind farms in NSW would probably be less than 5% of installed capacity.

For comparative purposes the South Australian Electricity Supply Planning Council in their 2007 Annual Report concludes: *that based on recorded wind performance during the top 10% of demand periods, 95% of the time wind generation in South Australia is producing 6-8% of its installed capacity and for 50% of the time it is producing at least 21% of its installed capacity*. The 6-8% value for South Australia is similar to the assumed 5% for NSW.

The 5% level of installed wind power considered as “firm” power based on the 95% confidence level is considered appropriate for system planning purposes. The 50% confidence level implies a 50% reliability of wind farm capacity being available when it is required to meet system demand.

While it is acknowledged that wind generation is normally dispatched in high merit order due to its low marginal cost of generation and therefore contributes to system generation like a base load generator, its implied 50% reliability to generate is a significant disadvantage. A coal fired or gas fired plant with a similar level of generation reliability would not be considered as being a base load generator.

However, the implementation of wind forecasting systems by NEMMCO and requirements by NEMMCO to limit wind farm output to dispatch levels during network-critical periods is likely to limit these potential impacts to some extent.

4.5.3 Environmental

Wind is a renewable generation resource with the level of greenhouse gas emission savings being dependent on the emissions otherwise produced by the generation it displaces on the grid.

The major environmental issues for wind farm developments tend to be visual impact and noise, although generally noise impacts can be managed satisfactorily using appropriate setbacks from residences. Due to the size of the wind turbine structures the visual impacts tend to be the main issue on which objections are based. However, the fact that around 470 MW of wind farm development has already been approved in NSW indicates that the environmental issues relating to wind farms can be addressed satisfactorily in most cases.

4.5.4 Financial Factors

Typical wind farm costs are (depending on site-specific conditions):

- Construction Cost:	\$1800-\$2500 / kW
- O&M Cost:	\$9 / MWh (SO) (based on 1.6% of construction cost (ESIPC 2003))

With a typical capacity factor of approximately 30%, the resultant cost of generation may be \$70 - \$90/MWh(SO) (depending on the site) when financing costs are considered.

Most of the wind farm capacity developed to date in the eastern NEM states has been supported by the MRET Scheme. Renewable Energy Certificates (RECs) that have been generated under this scheme have substantially been fully committed, until the end of the scheme in 2020. Without further extension of this scheme, it is likely that most future wind farm development will be dependent on alternative State-based schemes such as the Victorian Renewable Energy Target (VRET) scheme already introduced in Victoria and the NSW Renewable Energy Target (NRET) scheme proposed for introduction this year. Without these schemes it is unlikely that significant wind farm development will take place in the eastern NEM states.

Under the current VRET Scheme renewable generation is limited to Victoria while the proposed NRET Scheme is expected to allow renewable generation in any of the NEM states. When the NRET Scheme is introduced it is anticipated that the VRET Scheme will be amended to also allow renewable generation in NSW to be regarded as eligible generation.

Even so, the likely potential for wind farm development within NSW as a result of these renewable energy target schemes will be dependent on the commercial competitiveness with other renewable generation sources as well as with wind farms in other states.

The introduction of an emissions trading scheme will increase the marginal price of electricity from plant using fossil fuels and improve the competitiveness of wind and other renewable base load electricity generating technologies. Until the details of such a scheme are known the impact on the renewable energy measures will also be difficult to quantify. However, it could be expected that the degree of support required from renewable measures will reduce as the price of fossil fuel based electricity increases in line with the price of permits.

For wind generation in NSW, no economic modelling of the likely resultant generation mix from the NRET Scheme introduction (or an expanded VRET Scheme) has been published so it is difficult to estimate the likely ranking of available renewable projects that could participate in these schemes.

However, while on average the available wind resource in NSW tends to be lower than that in the southern states, there are a number of potential wind farm sites in NSW that would be viable compared to some projects being proposed in other states.

In the context of this study relating to base load generation, Connell Wagner estimates that a further 750MW of wind generation in NSW could be developed over a 2-10 year period. Even if 5% of this were considered as “firm” power (as discussed above) this would only result in a maximum of 37MW of base load power. As noted earlier, renewable technologies with support from other dispatchable plant can provide firm capacity but the amount that is considered firm would be to a large extent only in proportion to the amount of support provided by the dispatchable plant.

4.5.5 Suitability for Base load in NSW

The suitability of wind generation for base load generation in NSW is primarily limited by the variability of the wind resource with less than 5% of installed wind capacity being considered as “firm” power in its own right.

In the absence of any renewable support initiatives from the Federal Government future wind farm developments in the NEM states generally will primarily be dependent on the State-based renewable energy target schemes. Even so, potential wind farms in NSW will need to compete with wind farm projects in other states.

It is considered that around 750MW of further wind power could be developed in NSW of which less than 5% (37MW) could be considered as “firm” power at peak times.

4.6 Solar Thermal

4.6.1 Description

The Solar Thermal Energy (STE) concept uses heat generated from solar radiation, typically concentrated using reflectors, to provide the temperatures necessary to transfer the solar energy to a working fluid or a heat engine. Solar energy also integrates easily with thermal power station technology.

The energy can be collected and concentrated using the following systems:

– Parabolic Troughs – use parabolic shaped mirrors to focus the sunlight onto receiver tubes through which a heat transfer fluid is passed. The fluid is heated by the sun and used to produce a hot fluid that can power a turbine generator. A heat transfer fluid transfers the energy away from the receiver, and can be used to create steam.

– Compact Linear Fresnel Collectors – are typically in the shape of a shallow trough arranged in multiple lines, that reflect light onto a fixed thermal receiver. One of the main advantages is the potential for reducing the cost of the system, as flexible connections containing the hot gas or fluid are not required and the reflecting array sits on the ground and can be constructed with standard low cost materials.
– Solar Tower Systems – use an array of heliostats (large individually-tracking mirrors) to focus sunlight onto a central receiver mounted on top of a tower. Water / steam systems, compressed air and molten salt receivers have been demonstrated or are under development.
– Dish/Engine Systems – use parabolic dish-shaped mirrors to focus solar energy onto a receiver located at the focal point of the dish. Fluid in the receiver may be heated and used to generate electricity in an engine attached to the receiver. The dish could also be used to heat fluid for use in a centralised heat engine, such as a Stirling Engine.

STE can also be used with similar power plant technology as is used in existing power stations. It can also be integrated with other heat sources to provide supplemental energy to a power plant using fossil fuels. This latter arrangement would reduce the greenhouse gas emissions of a plant using fossil fuels while still providing a secure power source when the sun is not shining.

Solar thermal technology is still at a relatively early stage of development and more research is required particularly in the areas of cost effective solar collection and energy storage. The technology is used for electricity generation in the USA where the largest plant in the world is the Solar Energy Generating System (SEGS) plant in which parabolic troughs are used to provide the energy for 354 MW of generating capacity. A new plant of 64 MW capacity has recently been commissioned (2007) in Nevada by Acciona Energy and will produce 134,000 MWh per year, the first large solar thermal plant in about 16 years (Acciona 2007). In Spain there are several 50 MW plants in the development stage. Integrated Solar Combined Cycle Systems (ISCCS) using combined solar and gas fired combined cycle plants are in various stages of planning in southern California, India, Morocco, Mexico and Algeria.

In Australia the company Solar Heat and Power have developed a low cost Compact Lineal Fresnel Reflector (CLFR), based on the work of Dr David Mills. The technology has the potential to reduce the overall cost of electricity from solar resources making it competitive with a moderate carbon impost (Mills, 2006). This technology has been installed at Macquarie Generation's Liddell Power Station in NSW to provide preheating for boiler feed water.

4.6.2 Performance

Solar thermal technology has access to a large practical resource that is estimated to be about 5000 times human energy use (Mills, 2006). Figure 4.2 shows the solar exposure across Australia and indicates that greatest potential for STE in NSW is in the western regions of the State.

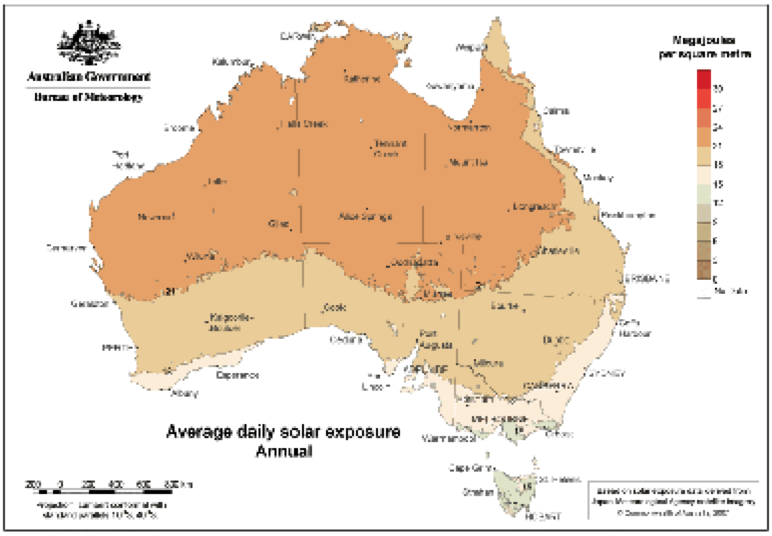

Figure 4.2 Solar Resources in Australia (BOM, 2007)

For solar thermal power plant, similar to the most recent installation in Nevada, USA as noted above, an area of approximately 7 km by 7 km would be required to supply the equivalent electricity output of a typical 660 MW coal fired unit installed in NSW.

The solar resource varies during the day, according to weather conditions, it also drops in winter and completely disappears at night. For this reason alternate generating systems or energy storage systems are required, such as molten salt or thermal oil, if STE were to provide electricity supply at times other than while the sun was shining.

The primary market for parabolic trough technology is large-scale bulk power. Because trough plants can be hybridized or can include thermal energy storage, they can provide firm capacity to utilities. Capacity factors for current parabolic trough systems under development range from approximately 20% for solar only plants to greater than 40% for plants with thermal storage. Such plants provide firm peak to intermediate load capacity. As the cost of thermal storage is reduced, future parabolic trough plants could yield capacity factors greater than 70%, competing directly with future base load combined cycle plants or coal plants (NREL, 2007). One advantage of STE is its operation during times of high summer demand and at high pool prices during the day.

Solar thermal technology has the potential to make a significant contribution to the production of electricity due to the wide spread solar resource with further development of the systems, energy storage and cost reductions.

4.6.3 Environmental

The advantage of using the STE energy source is that it has no greenhouse gas emissions or other environmental impacts similar to conventional coal fired power plant. The water requirements for a solar thermal plant using steam would be similar to a fossil fuel plant but can also be ameliorated in the same way by using dry cooling.

The main significant environmental impact would be large areas of land are required to produce electricity. The loss of productive land, could cause concern in the affected rural communities.

4.6.4 Financial Factors

The cost of power from a solar thermal power plant is mainly due to the initial construction investment cost and the low capacity factor, the fuel cost is zero as the energy input is free. This makes the marginal cost of generating very low and competitive with coal fired plant in this respect. However, once the return on capital is factored it would require that the investor receive a relatively high price for the electricity for the economic life of the plant, to make a project financially viable.

Since the technology is still in an early stage of development the construction cost is expected to reduce as experience is gained. The Linear Fresnel Array if substituted for the parabolic trough, on which most existing operating systems are based, has the potential to further reduce costs (Philibert 2004).

No power station producing electricity based on STE is in operation in Australia and consequently costs are based on experience in the USA, with a direct price conversion applied as noted previously. The “all in” plant costs for previous concentrating solar plants resulted in electricity prices in the range $170 to $210/MWh(SO). Technology improvements have since reduced this price to $120 to $150/MWh (Solarginix 2005). Cost reductions for solar plants are related to the installed MW and further technology improvements. The approximate cost of a solar plant is estimated to be around $3000/kW (Solarginix 2005) based on US conditions.

The levelised cost of electricity from solar thermal is likely to reduce as a function of MW installed. At the 5000MW level it has been estimated (Solarginix 2005) that electricity may be able to be produced at $80/MWh.

4.6.5 Suitability for Base load Power Generation in NSW

Solar thermal power plant has some of the characteristics attributed to base load plant, the most important being low marginal cost. However the ability to operate at high capacity factors is not possible unless it is coupled with an energy storage system or in concert with a power plant that can operate when the solar energy is not available.

The question of suitability for base load in NSW is related to whether the technology can currently perform in the manner expected of a base load plant. Solar thermal electricity costs are still high as it is still in a relatively early stage development, even though some systems have been operating for a number of years. The technology is not likely to reach a level of maturity in the time frame necessary to play a significant role in NSW base load supply. On this basis solar thermal would not currently be suitable for base load electricity supply.

However, it is evident that solar thermal technology, including thermal energy storage, has high potential in locations with suitable solar exposure such as Australia. To realise the potential, support that promotes the industry so that manufacturing can increase experience and economies of scale (Solargenix Energy 2005) would be necessary.

4.7 Geothermal - Hot Dry Rocks

4.7.1 Description

The Hot Dry Rocks (HDR) energy concept extracts heat from sub-surface rocks and changes the energy into electricity in a power plant located on the surface. The power plant is similar in concept to conventional steam driven power plants. Similar generating technologies are used in hydrothermal type plant where the water temperatures are relatively low. A typical arrangement is shown in Figure 4.3 where the process is shown as two sub-systems as follows:

– The reservoir sub-system with the HDR heat source connected by deep wells, and
– The power plant sub-system located on the surface.

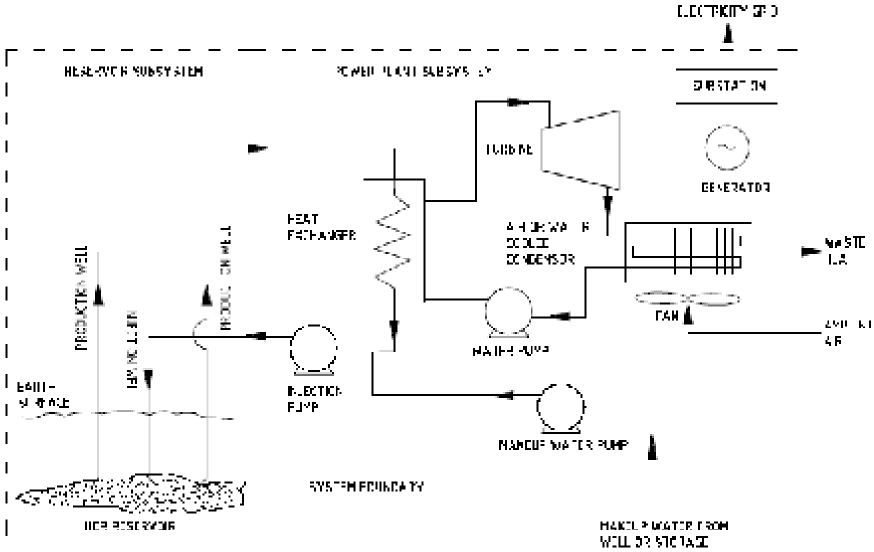

Figure 4.3 Hot Dry Rocks Electric Power System

In any specific HDR power system the arrangement may vary in detail from that shown in Figure 4.3 dependent on the particular characteristics of the resource, the location, the technology selected and the specific factors such as the availability of water.

Drilling wells down to the target rocks in the order of 2 to 5 kilometres deep provides access for the development of the reservoir system. Hydraulic fracturing of the hot rock is used to connect the injection and production wells. A typical arrangement is likely to have one injection well and two production wells called a triplet. As the power output is increased so does the need for more triplets to increase the rate of heat transfer to the surface.

Water is then pumped through the injection well and passes through the fractured rock where it is heated to a target temperature of around 250 degrees C and then returns to the surface through the production wells. The system requires a source of water to use in the process with a sufficient supply of water to make up for any losses that occur in the process through underground leakage. (US DOE)

On the surface the power plant system operates as a closed system with the interface being a heat exchanger where heat is transferred between the HDR reservoir and the power plant. A Binary Cycle power plant system that uses a working fluid with more suitable characteristics to the low temperature source has advantages for the power plant cycle. The Kalina Cycle has been proposed for this application due to its inherently higher efficiency. In Figure 4.3 dry cooling has been shown as it may be necessary to reduce the water usage for the power plant as most HDR locations in Australia are in arid locations.

4.7.2 Performance

HDR potentially provides a very large energy resource that has sufficient energy to produce electrical energy for many years on a scale similar to exiting large coal fired power plants located in NSW.

The actual performances of a large-scale power plant using HDR energy is not known as none have been constructed, even to the demonstration stage in their entirety in Australia or elsewhere. However that is not to say that significant development work has not been done and that much of the technology is not proven. Binary power plants are available commercially and are used in hydrothermal power plants in some countries (eg New Zealand, USA, Italy).

In Europe (Soultz-sous-Foret, France) and the USA (Fenton Hill, New Mexico) test programs have been conducted over a period that have shown that the energy in the HDR reservoir can be extracted and returned to the surface (Ref Duchane, 1996). There is a program in place to install a small test power plant at Soultz-sous-Foret.

In Australia, the companies Geodynamics and Petratherm are making significant progress in the development of the HDR energy sources. Geodynamics is well advanced in the development of the reservoir and are planning to have a 13 MW demonstration power plant installed by 2008 in the Cooper Basin, near Moomba in South Australia.

The technical capacity factor for a HDR power plant should theoretically be similar to a conventional power plant. A high capacity factor would improve the economics compared to say wind farm that would have less than half of the capacity factor of an HDR plant. The reliability and availability of a power plant based on the HDR energy resource is not proven at this stage.

4.7.3 Environmental

The advantage of using the HDR energy source is that it has no greenhouse gas emissions or other environmental impacts like conventional coal fired power plant. Water is required to be circulated to transfer the heat and provided the losses in the reservoir are small, water usage should not be a major issue. Water may also be used for condensing the fluid in the power cycle, but if dry cooling is used, water for this purpose would not be necessary, albeit at a loss in efficiency.

4.7.4 Financial Factors

The cost of a HDR generation facility is difficult to assess at this early stage of development of the technology. Geodynamics indicates that it expects a commercial size plant to be comparable to coal fired plants for the cost of electricity (Geodynamics, 2007) once the technology is developed.

The marginal cost of electricity would effectively be low, as there is no fuel cost component. The construction cost for HDR is dependent on the cost of drilling holes between 3 to 4 kilometres in depth and the cost for the power plant technology to use the relatively low temperature hot water, when compared to steam cycles.

The power plant technology may be similar in cost to technology for hydrothermal using similar temperature resources.

Geodynamics information indicates that for a 300 MW HDR plant a cost of $40/MWh may be achieved but no time frame is indicated (MMA 2006). The IEA /OECD (2003) indicate that HDR may be in the range $330 to $500/MWh (converted from Euros at .60 to the AUD) but with no basis for the high cost. Klobasa and Ragwitz (2004) suggest a cost of approximately $100/MWh based on a resource temperature of 250C. These large variations in costs indicate the immaturity of the technology and the lack of any operating example, also reflecting the potential variation in the basis of the costs.

4.7.5 Suitability for Base load Power Generation in NSW

In NSW, Pacific Power and the Australian National University carried out an initial assessment of the potential for an HDR resource in NSW in the Hunter Valley near Muswellbrook during 1999. This work, carried out with funding from the Renewable Energy Commercialisation Program, involved drilling a hole 1946 m deep (Prame, 2003). Analysis from the hole and other studies indicated that a resource may exist at 5 km deep. Geodynamics acquired the geothermal tenement from Pacific Power.

At the present time HDR technology would not be suitable to supply base load power in NSW as it has not yet reached the stage of development that would be necessary for a large investment as a base load generator. In addition, unlike South Australia, there are no proven HDR resources in NSW.

4.8 Biomass Thermal

Biomass is material produced by photosynthesis or is an organic by-product from a waste stream. (Saddler et al, 2004). It includes a wide variety of renewable organic materials, including forestry and agricultural wastes and residues, urban tree trimmings, food processing wastes, woody weeds, oil bearing plants, animal manures and sewage, energy crops and the organic fraction of municipal solid waste. In photosynthesis, growing plants capture solar energy and CO_2 from the atmosphere to form carbohydrates. These may be used either by combustion of the solid fuel, or by converting them into other forms of stored energy, such as biogas, methanol and ethanol.

The objective of this report is to consider the potential for technologies to be used for base load electricity generation. Biomass covers a multitude of different types of energy resources and only those with the potential to supply significant energy for electricity generation will be considered. These would include wood waste, energy crops and agricultural residues such as bagasse and straw.

There are also numerous technologies available or under development that can be used for energy conversion of biomass, these include

- Thermo/chemical technologies including direct combustion, gasification and pyrolysis.
- Biochemical technologies including anaerobic digestion

Direct combustion is the most common process in Australia for the larger capacity power plants.

4.8.1 Description

Solid biomass material such as forestry and agricultural wastes can be viable fuel for power generation provided that the fuel does not have to be transported long distances or stored under cover. (Saddler et al , 2004). The thermal power station technology for utilisation of these fuels is well understood, commercially available and relatively low in cost. The utilisation process is in principle similar to coal based power generation, involving a boiler / turbine system. Boiler designs tend to be stoker or moving grate types but also include fluidised bed. These are proven designs with many operating plants.

In Australia there is currently around 600 MW of biomass based power generation (ORER, 2007), including bagasse, wood waste, landfill methane and sewage methane. This includes 92 MW in NSW, 58 MW of which is either bagasse or wood waste. Both Delta Electricity and Macquarie Generation have co-fired wood waste with coal at a number of their power plants.

4.8.2 Performance

Biomass fuels are characterised by a low energy content and high moisture level compared with black coal. The high moisture level results in a low boiler thermal efficiency. When used in purpose built facilities that are typically around 30 – 50 MW in size, the overall thermal efficiency of power generation may be as low as 20% but this is typical for fuels that have a moisture content similar to biomass. Plant reliability is expected to be high as the boiler technology and steam cycles are well established, low stress designs. Many feed stocks (such as bagasse) are seasonal, which can limit plant capacity factor unless alternative fuels can be sourced for the off season.

To date biomass plant have been most successful where the biomass is derived from another production process and the fuel is in one place ready to be used. The most common biomass in this respect is bagasse where it is produced as part of the sugar milling process.

4.8.3 Environmental

Biomass plant are attributed with no greenhouse gas emissions from their operation as long as the biomass can be shown to be a part of a regrowth cycle (there are constraints in regard to native forests). The air emissions include particulates and NOx, similar to other thermal combustion processes. Production and transport of fuel also has the potential to create environmental issues. Like other thermal processes using steam turbines the working fluid must be condensed by cooling and this requires water unless dry cooling is used, which decreases efficiency.

4.8.4 Financial Factors

To date bagasse based projects have been proven to be cost effective but their uptake due to the MRET has been slow, compared to wind. The cost effectiveness is due to the integration of a co-generation facility with a sugar mill and the fuel being available as waste product from sugar milling. There is little impediment to financing a biomass plant as they are well understood and common technology.

The use of agricultural wastes and timber waste that is not already collected, which is the majority, incurs additional cost that is dependent on the distance and the nature of the resource. This tends to limit the capacity of the plant and consequently the economies of scale that can be achieved.

The cost of electricity produced from biomass is particularly dependent on the resource, which could range from zero for bagasse to $25/tonne or more for wood due to the cost of collection or an alternate market. The following long run costs are provided as an indication (MMA, 2003). The construction cost of a biomass plant is estimated at $2000/kW, based on Connell Wagner experience.

Bagasse	50 to 100 $/MWh
Rural Biomass	50 to 120 $/MWh

For any significant base load application using biomass it is unlikely that reliance could be placed on the continued use of low marginal cost waste products. The demand for fuel would alter the cost structure of biomass energy resources, as they would need to be cultivated to meet demand.

4.8.5 Suitability for Base load in NSW

The main impediment to the use of biomass for base load in NSW is the fuel resource, related to the cost of transporting fuel to a central site which then results in limiting the scale of the plant, if the fuel is to be kept at a reasonable price. For some fuels the seasonal nature is also an impediment to the use of the technology as base load plant, as storage of fuel is problematic.

5. Review of Carbon Capture Technologies

5.1 Overview

In response to the enhanced greenhouse effect, the worldwide scientific community, coal industry and electricity generators believe that carbon capture and storage is a viable option for the mitigation of climate change. Carbon dioxide capture and storage is a process consisting of (IPCC, 2005):

i) Capture or separation of CO_2 from industrial and energy related sources

ii) Transport of CO_2 to a storage location

iii) Injection into storage site for long term isolation from the atmosphere

The potential for these systems to limit the carbon footprint of the electricity and industrial sectors is extremely large (EPRI, 2007).

When coal or natural gas is burned for power generation, an exhaust (flue) gas stream comprising predominantly nitrogen, carbon dioxide, water vapour and oxygen is produced. Typically, the CO_2 concentration of the flue gas is approximately 15% (v/v). For a large coal fired power plant, the flue gas production rate is very high. For example a 660MW coal fired power plant operating at its rated capacity may produce between 900 and 950 cubic metres of flue gas per second (m^3/s). (Connell Wagner calculations)

The storage of CO_2 from sources such as power plants requires that the CO_2 is first isolated from other gases. This is because it would be impractical to store flue gas with all its constituents due to costs associated with transportation and compression as well as storage space considerations. (GCEP, 2005).

The removal of the CO_2 from the flue gas stream requires very large equipment and substantial quantities of energy. Separation of CO_2 from gas mixtures is commonly performed in industries such as beverage manufacture and urea production. However in these industries, CO_2 removal is carried out at a very small scale compared to the requirement for CO_2 capture from power plants. The following sections will describe the technology options for separation of CO_2 from the flue gas streams of fossil fuel fired power plants and options for long term isolation from the atmosphere.

5.2 Generic Carbon Dioxide Capture Technologies

There are three generic types of CO_2 capture systems demonstrated or proposed for fossil fuel fired power plants (EPRI, 2006b):

Post- combustion: This system involves the capture of CO_2 from all or part of the flue gas stream. A number of technology options are available, a few of which are commercially used for the separation of CO_2 from natural gas.

Oxy-fuel combustion: This technology entails burning the fuel in high purity oxygen. This results in high CO_2 concentrations in the flue gas stream and therefore easier separation.

Pre- combustion: This option is only suitable for the IGCC generation technology. It involves the separation of hydrogen and carbon dioxide prior to the combustion of the syngas. The technology is widely applied in the manufacture of fertilisers and in hydrogen production.

These capture systems are discussed in detail in the following sections.

5.2.1 Post Combustion Carbon Dioxide Capture

Post-combustion capture systems have been the subject of significant development effort as they may be suitable for retrofit to existing power plants. There are several technologies that are either presently used or have been proposed for the removal of CO_2 from flue gas streams. They include:

Chemical absorption processes: These are based on chemical solvents and are currently the preferred option (IPCC, 2005) for post-combustion CO_2 capture. Absorption processes in post-combustion capture make use of the reversible nature of the chemical reaction of an aqueous alkaline solvent, usually an amine, with an acid. Typically, post-combustion capture involves two stages: First, flue gas is passed through an absorber, where a solvent removes most of the CO_2 through a chemical reaction. Then this CO_2 - rich solvent goes to a stripper, where it is heated to release the CO_2 and produce a regenerated solvent, which is returned to the absorber. Figure 5.1 illustrates the process schematically.

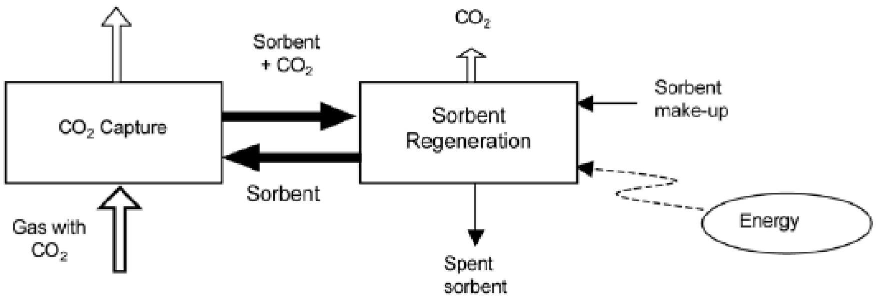

Figure 5.1 Schematic of Chemical Absorption CO2 Capture Process (IPCC, 2005)

Physical absorption: Physical absorption processes involve the use of absorbents that allow CO_2 to permeate a solid or liquid under given conditions, and to desorb under other controlled conditions. Physical solvent scrubbing of CO_2 is established, with Selexol, a liquid glycol based solvent having been used by the natural gas industry for many years. A characteristic of the Selexol process is the low pressure release of CO_2, resulting in additional compression following release.

Membrane separation: Membrane separation systems comprise thin barriers that allow the selective permeation of certain gases, allowing a particular gas to pass through at a higher rate than others. This type of gas separation has been widely used for hydrogen recovery in ammonia synthesis, removal of CO_2 from natural gas and nitrogen separation from air (GGEP, 2005). Figure 5.2 provides a schematic illustration of the membrane separation concept.

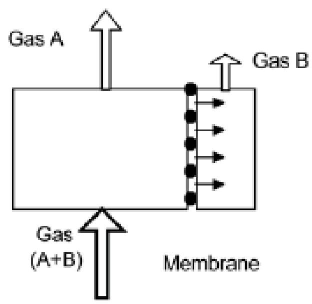

Figure 5.2 Membrane Separation Process

Solid sorbents: Under some conditions, CO_2 can undergo a reversible chemical reaction with a dry absorbent material. The chemical reaction can later be reversed by changing the conditions, resulting in the release of pure CO_2.

Cryogenic separation: Cryogenic separation or low temperature distillation allows separation of CO_2 from O_2 / N_2 gas mixtures due to the differing boiling points of these gases. A characteristic of this method of separation is the high refrigeration energy requirement.

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5.3 Potential Carbon Dioxide Capture Technologies.

A number of the proposed CO_2 capture technologies are still at the laboratory or pilot stage and therefore would not be suitable for use with a base load power station at present. Table 5.1 lists the carbon dioxide capture technologies that have been identified and indicates the state of development of the technology.

Capture Type	Technology	Status of Development
Post Combustion	chemical absorption - amine	economically feasible under specific conditions
	chemical absorption -chilled ammonia	demonstration phase
	membrane separation	economically feasible under specific conditions
	solid sorbent	research phase
	cryogenic	economically feasible under specific conditions
Oxy- Fuel Combustion		demonstration phase
Pre- Combustion	physical absorption -Selexol	economically feasible under specific conditions
	physical absorption -Rectisol	economically feasible under specific conditions

Table 5.1 Commercial Status of Potential CO_2 Capture Technologies

Critical factors that will impact the suitability of the CO_2 capture technology to be used with base load power generation include:

- maturity and timeframe for availability
- construction cost
- energy consumption and impact of system on power plant output and efficiency
- operating costs
- CO_2 capture efficiency
- requirement for gas pre-treatment

Recent studies suggest that the largest near-term contribution to reducing the cost of post-combustion capture could come from finding better solvents for absorbing and desorbing CO_2, specifically solvents that could process larger amounts of CO_2 for a given mass of solvent and that would require less energy to drive the desorption process. (EPRI, 2007). Carbon dioxide capture technologies that are at or nearing commercialisation are discussed further below with respect to these parameters

5.3.1 Amine Solvent Process

Description

The most commonly used chemical absorption process for CO_2 capture uses monoethanolamine (MEA) as a solvent. The process is widely used in the beverage industry and for chemicals production.

CO_2 in the gas phase dissolves into a solution of water and amine compounds. The amines react with CO_2 in solution to form protonated amine (AH+), bicarbonate (HCO_3-), and carbamate (ACO_2 -) (GCEP, 2005). As these reactions occur, more CO_2 is driven from the gas phase into the solution due to the lower chemical potential of the liquid phase compounds at this temperature. When the solution has reached the intended CO_2 loading, it is removed from contact with the gas stream and heated to reverse the chemical reaction and release high-purity CO_2. The CO_2-lean amine solvent is then recycled to contact additional gas. The resulting pure CO_2 stream is recovered at pressures near atmospheric pressure. Compression, and the associated energy costs, would be required for geologic storage. Research on improved solvents with reduced regeneration energy is underway.

Maturity and timeframe for availability

Commercial amine absorption systems are available from a number of vendors. However a scale-up by a factor of 10 or more is required to achieve a power plant scale installation (IPCC, 2005). The technology also requires integration and demonstration with a robust and proven ultra-supercritical coal or CCGT power plant technology. A recent EPRI publication (Dalton *et al*, 2007) suggests that carbon capture and storage technologies for power plant applications will not be commercially available until 2020.

Performance

Amine scrubbing systems are capable of the removal of between 80 and 95% CO_2 in a flue gas stream.

Energy Consumption

Amine systems have a relatively low CO_2 loading capability and a relatively high energy requirement for regeneration.(EPRI, 2007). A study by EPRI found that the scale up of the MEA technology to coal fired power plant size would result in a system that would reduce the net power output of the power plant by 29%, raising the cost of electricity production by 65% (EPRI, 2007).

Gas Pre-Treatment

It is essential that acid gases such as NOx and SOx be removed from the flue gas prior to passing through the absorber tower. NOx and SOx reacts with the amine and will result in a reduction in solvent performance and higher chemical consumption.

Financial Factors

Although no full scale commercial CO_2 capture plants are in operation on coal fired power stations, cost estimates have been published in various studies. Amine capture on a new pulverised coal fired plant is estimated at US$400 – 500 / kW (IPCC, 2005).

Suitability for base load in NSW

This technology is not considered mature enough for application to a full sized plant in NSW at present.

5.3.2 Chilled Ammonia Process

Description

This process is also a chemical absorption process but using ammonia rather than an amine as the solvent. Ammonia reacts with CO_2 and water to form ammonium carbonate or bicarbonate.

Maturity and timeframe for availability

Alstom (the French company who provide equipment and services for power generation and rail transport) is developing the process. A system is proposed to be installed on American Electric Power's (AEP) 1300MWe Mountaineer plant in West Virgina, USA. The pilot installation is planned to treat a 100,000 tonnes per annum slip-stream on the existing plant. AEP have stated (AEP, 2007) that they have plans for a commercial installation on a 450MWe unit at their Northeastern Station in Oklahoma.

EPRI are planning to build a 5 MW pilot plant to test the chilled ammonia capture technology. The plant will use flue gas from an operating coal fired power plant. Testing is expected to be carried out between 2008 and 2010 (EPRI, 2006). As this technology is not as developed as amine scrubbing it is also unlikely to be commercially available until at least 2020 (Dalton *et al*, 2007).

Energy Consumption

An advantage of chilled ammonia over amine systems is the low temperature solvent regeneration. (Ericson, 2006)

Gas Pre-Treatment

Alstom claim that the process is tolerant to oxygen and other contaminants in the flue gas.

Financial Factors

The chilled ammonia process is being developed as a lower cost alternative to the amine process. The ammonia based sorbent is claimed to be less expensive than amine sorbents, which should lead to lower O & M costs. A lower energy requirement for sorbent regeneration should result in a lower overall power consumption.

Suitability for base load in NSW

As the technology is still at the demonstration stage it is not yet suitable for use with base load generation in NSW

5.3.3 Physical Solvent Processes

Description

These processes are quite mature, having been used by the chemical industry since the 1970s. (UOP LLC, 2002). Solvent capture units are presently available at power plant scale. Selexol and Rectisol are trade names for an acid gas removal solvents that can separate acid gases such as hydrogen sulfide and carbon dioxide from feed gas streams such as synthesis gas produced by gasification of coal, coke, or heavy hydrocarbon oils. The Selexol trade name is held by the American chemical company UOP LLC and Rectisol held by Lurgi AG of Germany.

Existing IGCC facilities use these processes for the removal of sulphur from syngas prior to combustion. Processes such as Selexol and Rectisol are applicable to gas streams that have a high CO_2 partial pressure or total pressure. High pressure syngas from a coal gasification system is such a gas stream. Solvents such as Selexol absorb the CO_2 for later thermal regeneration.

Performance

The Selexol process is capable of removing more than 85% of CO_2 from a gas stream. (UOP LLC, 2002).

Energy Consumption

These processes require energy to regenerate the solvents to remove the CO_2. Capture and CO_2 compression on a 250MW IGCC plant would require 40MW of additional auxiliary power consumption (Wibberley *et al,* 2006).

Financial Factors

As stated above, these processes are for the pre-combustion removal of CO_2 from syngas. There is a significant impact of the technology on the $/kW cost of the plant due to the construction cost increasing and the quantity of sent out electricity decreasing.

Published data (Wibberley *et al* , 2006) suggests that the increase in IGCC plant construction cost with pre-combustion capture and compression would be around $600/kW. The increase in electricity production cost was estimated at 50%.

Suitability for base load in NSW

The Selexol and Rectisol processes are only applicable to Integrated Gasification Combined Cycle technology. As such they are not suitable for use with pulverised coal technology. Should IGCC be adopted as a base load technology, physical absorption processes such as Selexol and Rectisol should be considered.

5.3.4 Oxy-Fuel Combustion Capture Systems

Description

Oxy-firing involves the combustion of a fossil fuel in a mixture of oxygen and recirculated flue gas in order to reduce the net volume of flue gases from the process and to substantially increase the concentration of carbon dioxide in the flue gas. Oxygen combustion combined with flue gas recycle increases the CO_2 concentration of the flue gas from around 15% for conventional pulverised fuel firing up to a theoretical 95%. (CCSD, 2007) An oxy-fuel system is illustrated in Figure 5.3.

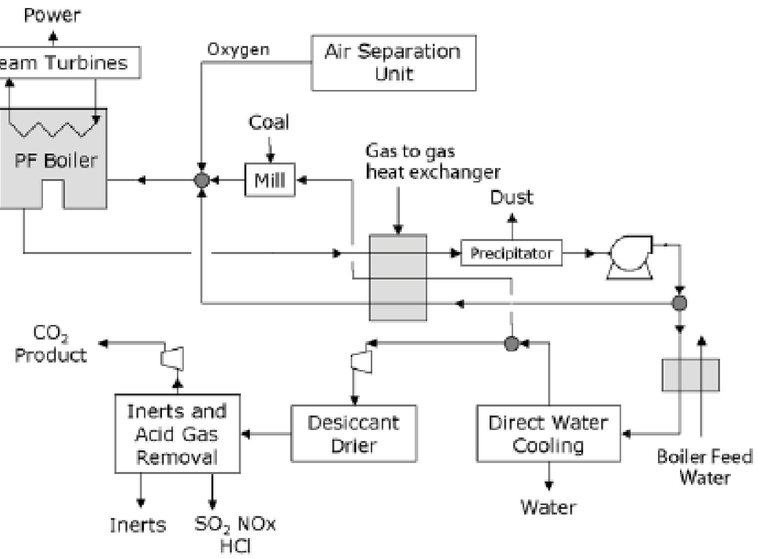

Figure 5.3 Oxy-fuel Combustion System for Pulverised Coal Fired Plant (IPCC, 2005)

The full-scale application of oxy-fuel technology is still under development. There have been a number of investigations using pilot-scale facilities in the US, Europe, Japan, and Canada. Studies have also assessed the feasibility and economics of retrofits and new power plant.

Performance

The capture efficiencies are close to 100% in oxy-fuel systems.

Energy Consumption

Energy consumption is very much a function of the method of oxygen production used. Options include cryogenic and membrane separation.

Gas Pre-Treatment

Impurities in the flue gas of an oxy-fuel system are predominantly SOx, NOx and N_2 from the in leakage of air.

Financial Factors

Preliminary cost evaluations indicate CO_2 capture costs ($/t$CO_2$ avoided) and electricity costs ($/MWh) comparable with other technologies and lower than conventional PF with amine-based post-combustion capture of CO_2.

Suitability for base load in NSW

Technical challenges include investigation of flame stability, heat transfer, level of flue gas clean up necessary and acceptable level of nitrogen and other contaminants for CO_2 compression, and corrosion due to elevated concentrations of SO_2/SO_3 and H_2O in the flue gas.

Following the proposed demonstration of the technology at Callide A power station in Queensland (Wall, 2007), an assessment could then be made of the suitability of the technology for use in NSW.

5.3.5 Membrane Separation

Description

Membrane processes are used commercially for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Developments in membrane separation such as hybrid membranes with absorbent or solvent systems may overcome some of the shortcomings described below.

Performance

The maximum quantity of carbon dioxide removal is lower than for amine chemical absorption processes.

Energy Consumption

The removal of CO_2 using commercially available gas separation membranes results in large efficiency penalties compared with the amine chemical absorption process.

Financial Factors

The compact size of membrane systems offers construction cost savings compared to chemical absorption processes.

Suitability for base load in NSW

Commercially available membrane separation systems are inferior to chemical absorption processes. It is not believed that the technology is mature enough for consideration for use with base load electricity production.

5.4 Application of CO_2 Capture to NSW Generation Options

To allow comparison of fossil fuel technologies with renewable and nuclear options, estimates have been made of the construction and operating costs of fossil fuel plants equipped with CO_2 capture equipment.

Many of the costs presented below on carbon capture and storage are based on overseas experience, and may not necessarily apply to Australian context. There are differences related to both the fuel properties and the structure of the power generation industry. This requires additional work to translate the work being done overseas to the Australian context. For example, American coals contain high sulphur (up to 5% by wt) and trace elements, whereas Australian black coals usually have less than 1.0% sulphur and a low level of trace elements (Gurba, 2007).

This has, for example, significant implications for both conventional and novel amine scrubbing processes, which require prior removal of SOx down to 10 ppm. The high level of sulphur in American coals also causes problems for oxy-fuel combustion plants due to corrosion resulting from SO_3 and sulphuric acid formation downstream of the furnace. These issues are likely to be completely different when firing low sulphur Australian coals (CCSD, 2002).

The overall cost of carbon dioxide capture will include construction costs of capture plant, pipelines and injection equipment, as well as operating and maintenance costs associated with these facilities. The energy costs of capture are significant and will be a major input to the capture and disposal cost. The CO2CRC believes that a carbon price of $20/ tonne of CO_2 avoided would make CCS technology technologically viable (House of Representatives, 2007).

As the issue of storage options is outside the scope of this study, the discussion of capture options assumes that compressed CO_2 ready for transport is produced from the capture facility.

5.4.1 Ultra-Supercritical Pulverised Coal with CO_2 Capture

This option involves a 'standard' ultra-supercritical pulverised coal plant with either oxyfuel firing or amine flue gas scrubbing. From available data from the literature, it is appears that the estimated construction costs and power consumption are similar for both technologies. In both cases there is a significant impact on overall plant construction and operating costs compared to the base no CO_2 capture case. There is a compounding impact of the power consumption associated with either oxygen production or amine regeneration. In both cases the sent out power is reduced by around 30%, thereby increasing construction costs per kW and operating costs per MWh(SO), even before the CO_2 capture costs are considered.

The expected characteristics of ultra-supercritical pulverised coal with CO_2 capture are summarised in Table 5.2:

Maturity	generation technology mature; CO_2 capture unproven on utility scale
kg CO_2 / MWh(SO)	~ 100
water consumption	increased over base case
environmental issues	CO_2 disposal sites
construction cost (A$/kW)#	3000 - 3500
fuel cost ($/MWh(SO))	11 - 20
major risks	CO_2 capture technology, costs and storage
Possible contributor to NSW base load	yes

Table 5.2 Characteristics of ultra-supercritical coal with carbon capture [# based on Connell Wagner coal fired plant costs and carbon capture costs from Wibberley, 2006]

5.4.2 Natural Gas Combined Cycle with CO_2 capture

This option involves a 'standard' natural gas combined cycle plant equipped with post combustion amine scrubbing for CO_2 capture. As gas turbine plants operate with very high excess air levels, the quantity of flue gas is higher, but CO_2 concentration is lower than with a coal fired plant. As for the coal fired plant fitted with amine scrubbing, the scrubber consumes a significant percentage of the plant output.

The expected characteristics of natural gas fired combined cycle plant with CO_2 capture are summarised in Table 5.3:

Maturity	generation technology mature; CO_2 capture unproven on utility scale
kg CO_2 / MWh(SO)	40 - 70
water consumption	increased over base case
environmental issues	CO_2 disposal sites
construction cost (A$/kW)	1300# - 1700
fuel cost ($/MWh(SO))	> 33
major risks	CO_2 capture technology, costs and storage
Possible contributor to NSW base load	yes (note comment in Section 3.2.5)

Table 5.3 Characteristics of natural gas combined cycle with carbon capture (# EPRI, 2006b; * Connell Wagner estimate)

5.4.3 Integrated Gasification Combined Cycle with CO_2 capture

A significant difference of this option to the ultra-supercritical coal and natural gas combined cycle with CO_2 capture is that it involves pre-combustion capture of CO_2. Following the gasification process the syngas passes through a shift reactor and CO_2 separation process. This results in a hydrogen rich syngas being fed to the gas turbine. IGCC power generation at the demonstration stage commercial but requires integration and demonstration with capture. Purpose built hydrogen fired turbines need to be developed.

The main advantage of this system over post combustion capture systems is the significantly lower energy consumption. This is due to the high pressure gasification process, resulting in lower compression requirements and higher CO_2 concentration in the gas.

The expected characteristics of integrated coal gasification combined cycle plant with pre-combustion CO_2 capture are summarised in Table 5.4. There is significant disparity in the literature with regard to the construction costs of IGCC as previously noted and IGCC with carbon capture. For IGCC with carbon capture costs range from $1600/kW (Topper, 2006) to $4770/kW (Dalton *et al*, 2007). The construction cost estimate provided is based on Connell Wagner's analysis of available published cost data sources.

Maturity	no demonstration of IGCC with CO_2 capture
kg CO_2 / MWh(SO)	~ 100
water consumption	marginally higher than base
environmental issues	CO_2 disposal sites
construction cost (A$/kW)	3100 - 3500
fuel cost ($/MWh(SO))	9 - 16
major risks	IGCC and CO_2 capture technologies, costs and CO_2 storage
Possible contributor to NSW base load	yes – for plant in operation after 2020

Table 5.4 Characteristics of IGCC with carbon capture (see text for references)

Although construction costs are similar to ultra-supercritical with CO_2 capture, the lower power consumption results in a lower impact on the $/MWh(SO) fuel cost.

5.5 Carbon Dioxide Transport

Once separated from other gases and compressed, the CO_2 can be transported to the site of storage by pipelines, road, ship or rail. In practice, because of the huge volume involved, only pipelines and ships are cost-effective options.

The pipeline transport of CO_2 is a well understood and practiced activity (Cook, 2007). In the USA, for example, there are several thousand kilometres of CO_2 pipelines, used to transport CO_2 for use in enhanced oil recovery. In Australia, transport by pipeline is accepted, and widely used for natural gas. Therefore, pipeline transport of CO_2 in Australia is likely to be acceptable to the community.

Transport by road or rail may be technically feasible for small scale projects but is likely to be prohibitively expensive. Transport by ship may be feasible in some circumstances. At the present time there is at least one European vessel dedicated to the transport of high purity CO_2 for food processing. In the same way that LNG is transported around the world it would be technically feasible to transport large quantities of CO_2 from a coastal emission source to an offshore storage site. The costs of such a scheme are likely to be high; nonetheless it cannot be completely dismissed and may represent an option for the future.

However for the foreseeable future, transport of CO_2 by pipeline is the most practical and economic option. According to the IEA report CO_2 transportation costs depend strongly on the quantities and, to a lesser extent, on the distances involved (Gurba, 2007). Figure 5.4 provides indicative costs of CO_2 transport. The costs presented here are consistent with those tabulated in the House of Representatives (2007) study.

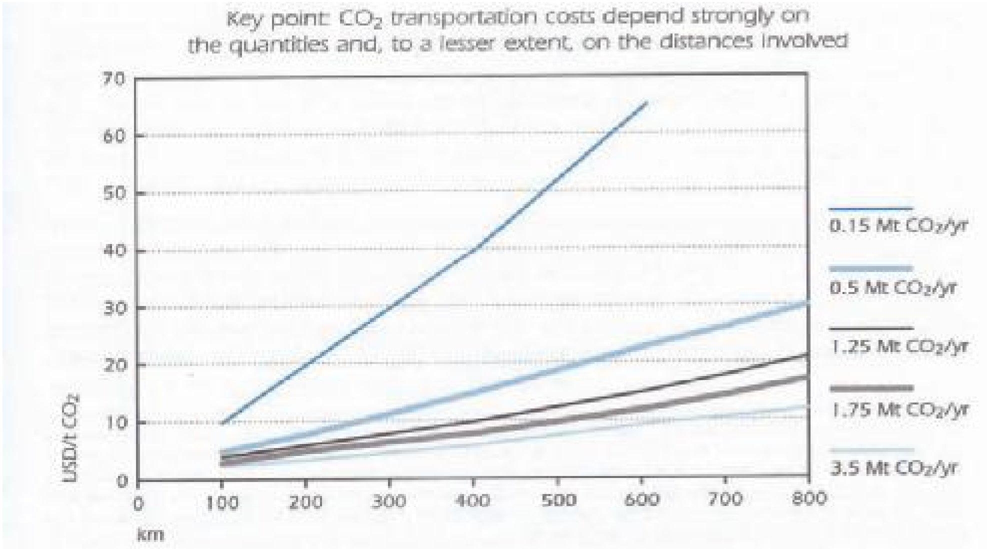

Figure 5.4 Indicative CO_2 transport costs (IEA, 2002)

6. Carbon Dioxide Disposal Options

There are a number of options that have been proposed for the long term isolation or capture of carbon dioxide from the atmosphere. They include (IPCC, 2005):

– Storage of CO_2 in deep geological formations either onshore or offshore
– Deep ocean storage
– The reaction of CO_2 with metal oxides, so as to convert the CO_2 into a mineral such as a metal carbonate.

These options are very site specific. However the generic description below is followed by discussion of the applicability of these options for NSW base load power generation.

6.1 Geological Storage of Carbon Dioxide

Several types of geological formations have been the subject of significant research effort to explore their suitability as long term carbon dioxide repositories. These options use technologies that have been developed by the oil and gas industries. The options include

– Depleted oil and gas reservoirs
– Enhanced oil recovery (EOR)
– Deep saline formations
– Deep unminable coal beds
– Enhanced coal bed methane recovery (ECBM)

In each of the above options, geological storage of CO_2 is accomplished by injecting it under pressure into rock formations below the earth's surface. Porous rock formations that have previously held gas or oil are obvious candidates for CO_2 storage.

The carbon dioxide storage effectiveness increases with depth, due to hydrostatic pressure influence on CO_2 density (Cook, 2006). Therefore CO_2 storage in hydrocarbon reservoirs is expected to take place at depths greater than 800m (IPCC, 2005).

6.1.1 Technological Maturity of Geological Storage

The different geological storage options are at varying stages of technological maturity. Enhanced oil recovery is considered to be a mature technology (Cook, 2006). It has been carried out in Texas, USA since the 1970s. Carbon dioxide from natural gas processing and oil production is injected for enhanced oil recovery. It has been estimated that 30 million tonnes of CO_2 is injected annually for EOR.

The use of depleted gas or oil reservoirs for CO_2 storage is considered to be economically feasible under certain conditions (Cook, 2006). Depleted oil and gas reservoirs are excellent possibilities for CO_2 storage for a number of reasons. The oil or gas that originally accumulated did not escape, demonstrating the integrity of the reservoir. Also, the geological structure and physical properties of most oil and gas fields have been extensively studied and characterised. Finally, some of the infrastructure and wells already in place may be utilised for handling CO_2 storage operations.

Presently there are three industrial scale CO_2 storage projects in operation in the world. These are the Sleipner project in an offshore saline formation in Norway, the Weyburn enhanced oil recovery project in Canada and the In Salah gas recovery project in Algeria. By 2008 it is expected that these three projects will be storing a total of 25 million tonnes of CO_2 per annum.

There is also a number of projects proposed that will involve the geological storage of CO_2. The presently proposed projects will increase the anticipated quantity of CO_2 stored annually to 35 Million tonnes by 2010 (Cook, 2006).

Geological storage via enhanced coal bed methane recovery is presently at the demonstration stage. If CO_2 is injected into a coal seam, it can displace methane, enhancing coal bed methane recovery. Carbon dioxide has been injected successfully at a number of North American locations. The injection of CO_2 for enhanced coal bed methane recovery has the potential to increase the amount of methane produced to almost 90%, compared to conventional recovery of 50% by reservoir-pressure depletion alone (IPCC, 2005).

6.1.2 Cost of Geological Storage of Carbon Dioxide

The technologies and equipment necessary for geological storage are extensively used by the oil and gas industries, therefore cost estimates are considered to be reasonably accurate. However site specific factors such as reservoir depth and permeability of the storage formation results in a high degree of variability of costs.

The following cost data was extracted from IPCC, 2005:

Storage Option	Indicative Cost
Saline formations	0.3 - 8US$ /t CO_2 injected
EOR, EBCM	Enhanced production of gas and oil may actually result in an overall net benefit 10 – 16$US/ t CO_2

6.2 Ocean Storage

As CO_2 is soluble in water, there is a natural exchange of CO_2 between the atmosphere and the surface of the ocean. As a result of increased atmospheric concentrations of CO_2 it has been estimated that the oceans have absorbed 500 Gt of CO_2 over the past 200 years. The impact of this has been a pH change to the upper ocean of 0.1.

It has been suggested that there is no practical limit to the amount of CO_2 that could be stored in the oceans (IPCC, 2005). However there may be ecological and environmental impacts of significant pH change.

It has been reported that the fraction of CO_2 retained in the ocean increases with increasing depth of injection (IPCC, 2005). This has led to a number of options being proposed for intentional ocean storage of CO_2 at an industrial scale:

– Deposition of a relatively pure stream of compressed CO_2 on the sea floor via a pipeline. At depths of greater than 3000m, CO_2 is a liquid and denser than water so will theoretically remain as a 'lake' on the sea floor.

– Loading CO_2 onto ships so the CO_2 could be dispersed from a towed pipe or transported to fixed platforms feeding a CO_2 lake on the sea floor.

– Water column release: Dispersal of liquid CO_2 at a depth of 1000 m or deeper is technologically feasible. CO_2 may be transported to the appropriate depth and released as a liquid or dense gas phase (achieved by compression beyond its critical point, 7.3MPa at 31°C). Then, this CO_2-rich water would be diluted as it disperses, primarily horizontally along surfaces of constant density.

Further options including disposal of CO_2 as a solid (dry ice torpedoes) or in hydrated form have also been proposed, whereby the CO_2 would sink and partially dissolve as it fell to the ocean floor.

6.2.1 Costs of Ocean Storage

Although there is no experience of ocean storage of CO_2, attempts have been made to estimate costs (IPCC, 2005). Costs for storage at depths of 3000m are indicated below. These costs assume that the compressed CO_2 is available at the shoreline.

The following cost data was extracted from IPCC, 2005:

Storage Option	Indicative Cost
Fixed pipeline to 100km offshore	$US6/ t CO_2 injected
Fixed pipeline to 500km offshore	$US31/ t CO_2 injected
Moving ship / platform for injection at a depth of 2,000 – 2,500m. 100km offshore	$US12 – 14 t CO_2 injected
Moving ship / platform for injection at a depth of 2,000 – 2,500m. 500km offshore	$US13 – 16 t CO_2 injected

6.2.2 Environmental Risks of Ocean Storage

All of the above options are still at the research stage of development. There is no empirical data on the impact of CO_2 on flora and fauna local to the release point and therefore limited knowledge of the sensitivity of deep ocean ecosystems to intentional carbon storage.

It is expected that ecosystem impacts will increase with increasing CO_2 concentrations and decreasing pH, but the nature of these consequences are not currently understood. No environmental criteria have as yet been identified to avoid adverse effects. At present, it is unclear how or whether species and ecosystems would adapt to the sustained chemical changes (IPCC, 2005).

For ocean storage of CO_2, issues remain regarding environmental consequences, public acceptance, implications of existing laws, safeguards and practices that would need to be developed, and gaps in our understanding of ocean CO_2 storage.

6.3 Stable Carbonate Conversion

This option refers to the conversion of CO_2 to stable carbonates using alkaline metal oxides such as magnesium oxide (MgO) and calcium oxide (CaO) which are present in naturally occurring rocks. Mineral carbonation produces carbonates that are stable over long time scales and can therefore be disposed of in areas such as silicate mines or re-used for construction purposes (IPCC, 2005).

Mineral carbonisation using silicates is at research phase but some processes using industrial wastes are at the demonstration phase. There is potential for significant CO_2 storage via carbonisation. As stated by IPCC (2005), *"The quantity of metal oxides in the silicate rocks that can be found in the earth's crust exceeds the amounts needed to fix all the CO_2 that would be produced by the combustion of all available fossil fuel reserves."*

6.3.1 Environmental Factors Associated with Carbonate Conversion

The environmental impacts of mineral mining, waste disposal and product storage need to be fully assessed. The quantities of minerals involved would require large scale operations.

6.3.2 Cost of Carbonate Conversion Technology

As mineral carbonate CO_2 technology is still at an early phase, it is difficult to estimate costs. There are many options for the source of the metal oxide and this will be a significant determinant in the cost of storage. A study on the wet carbonation of natural silicate olivine, found a cost of US$50 - $100 per tonne of CO_2.

6.4 Potential for CO_2 Storage in NSW

In 1999-2003 the Australian Petroleum Cooperative Research Centre (the precursor of CO2CRC) reviewed all of the Australian sedimentary basins for their geological sequestration options. The least explored state in terms of storage is NSW, partly because there has been little oil exploration in this state and little is understood about its deep geology (Cook, 2007).

On Monday 13 August 2007, the House of Representatives Standing Committee on Science and Innovation tabled its report on the inquiry into Geosequestration Technology entitled *Between a Rock and a Hard Place*. The report recommends that the Australian Government provide funding to CSIRO/CO2CRC to assess the storage potential for permanent CO_2 geosequestration in sedimentary basins of New South Wales, and the economic viability of these sites.

In fact very little is known about the deep rocks in NSW. That is, below 1000 metres as there has been very little deep drilling in the state (Cook, 2007). A key area, the offshore Sydney Basin, which is geographically ideally sited close to the Newcastle area is hardly known and has never been drilled. It may or may not be suitable for geosequestration. CO2CRC is now working with the New South Wales Government to undertake a comprehensive and definitive assessment for the storage potential of the State and views on the applicability of CCS to NSW must wait until that assessment is made (Cook, 2007).

Until August, 2007, little had been published on available geo-sequestration sites in NSW. However, it is understood that the three NSW generators are conducting studies into potential CO_2 storage sites in New South Wales (Jackson, 2007). Eraring Energy has stated that potential for geosequestration exists in the Darling Basin and to a lesser degree, the Gunnedah Basin. No public domain results of the NSW generator studies have been sourced.

7. Applicability of Technologies to NSW

7.1 Generation Technologies

A summary table of the salient features of each technology considered is provided in Appendix B. The key features of the non-renewable technologies are illustrated graphically in Figures 7.1a to c. Overall in terms of efficiency loss and costs of power, current studies indicate that energy loss and cost of electricity are comparable for pulverised coal fired plants with CO_2 capture and for IGCC with CO_2 capture. However the level of technology maturity and technology risks of these options as noted above, are very different.

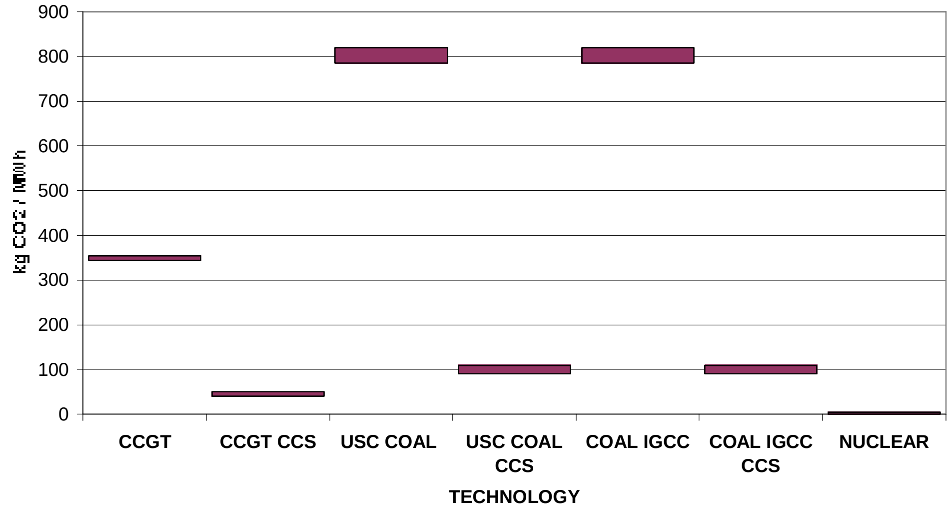

Figure 7.1a. Carbon Dioxide Emissions of Non-Renewable Technology Options

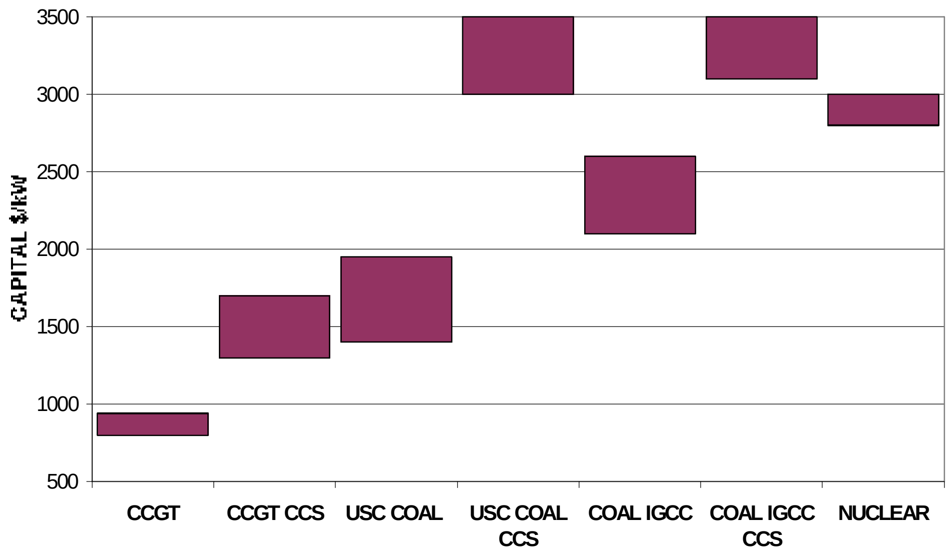

Figure 7.1b. Estimated Construction Costs of Non-Renewable Technology Options

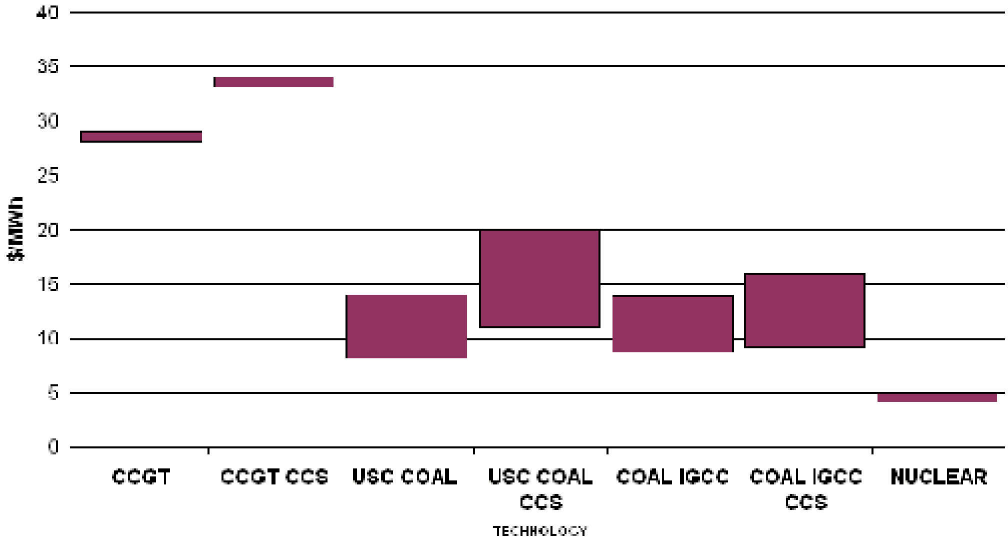

Figure 7.1c. Generation Cost (Fuel) of Non-Renewable Technology Options

The construction costs and expected cost of generation of renewable technologies are illustrated in Figures 7.2a and 7.2b respectively.

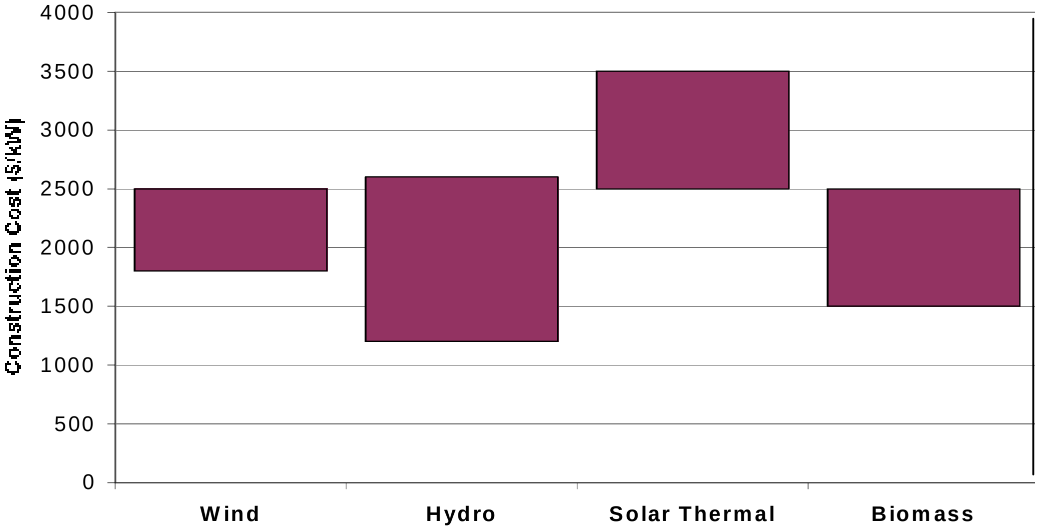

Figure 7.2a. Estimated Construction Costs of Renewable Technologies

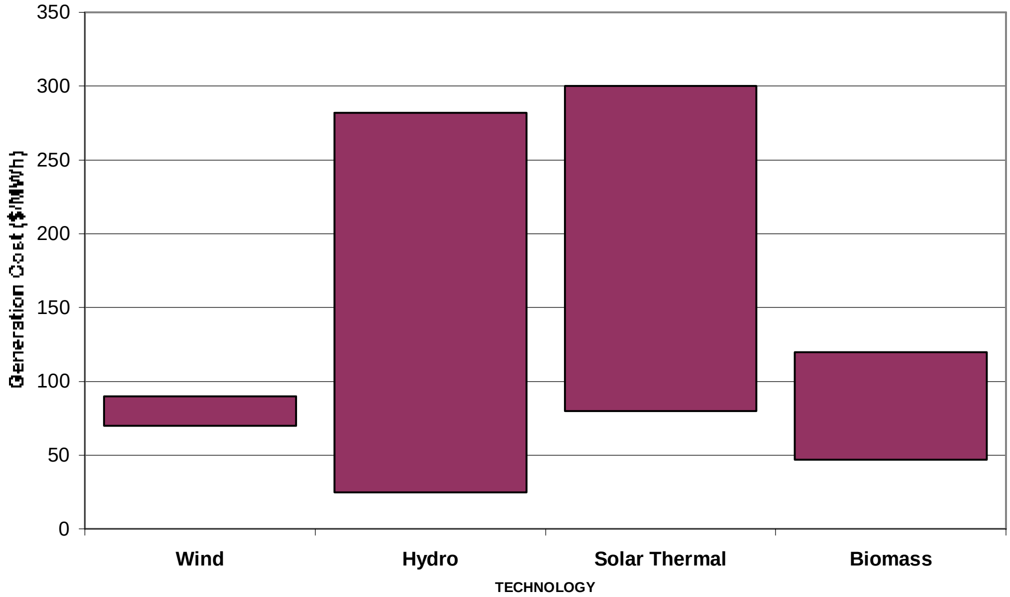

Figure 7.2b. Estimated Generation Cost of Renewable Technologies

A summary of the features of the technologies considered is provided in Table 7.1.

Fuel Type	Technology	Date of Commercial Operation	Suitability for NSW Base Load
Non-renewable	Ultra-supercritical coal	currently available	Yes
	Ultra-supercritical coal with CCS	CCS 2020	Yes – in future
	Combined Cycle Gas Turbine	currently available	Yes
	CCGT with CCS	CCS 2020	Yes – in future
	IGCC	2015	Yes – in future
	IGCC with CCS	CCS 2020	Yes – in future
	UCC coal CCGT	unknown	No
	Nuclear	Currently available	Yes. No regulatory regime
Renewable	Wind	Currently available	No – provides some base load energy
	Solar Thermal	Currently available but in early phase	No at present. Possible with further development
	Hot dry rocks	unknown	Yes – but unproven
	Hydro	Currently available	No – major sites not available
	Biomass thermal	Currently available	Yes – but some fuel sources seasonal

Table 7.1 Summary of Technologies

7.2 New Generation and the Load Duration Curve

This section of the report assesses how the new technologies may fit into the NSW operating environment.

The load duration curve as described previously indicates the percentage of time that the demand is greater than a certain MW level. The load duration curve for NSW, based on NEMMCO half-hourly demand data from July 2006 to June 2007 is shown in Figure 7.1. Only scheduled plant is included In the NEMMCO load data, implying that the actual total demand is higher than the NEMMCO data indicates.

In consideration of how the existing plant and proposed plant fit under the load duration curve, the following must be taken into account:

– There is a technical capacity limitation on the plant output that may change from day to day, as a result of outages, either planned or forced.

– The market positions and strategies of the generators may impact on the level of output of the plant, as will the prices bid into the pool.

– Wind generation may or may not operate at a particular time.

– Some plant will be called to provide Frequency Control and Ancillary Services (FCAS) by NEMMCO and will be on standby or acting as spinning reserve with capacity available for a contingency event.

– There are transmission limitations on the interconnectors to NSW (Snowy to NSW, Summer 2,800 MW and Snowy to NSW, Winter 3,300 MW (NEMMCO SOO Chapt 10)) and the flow is determined by market prices and demand.

Given all of the above points it is not possible to predict the output or the time of the output of any particular generator. Accordingly, this section can only compare new plant to existing to see if they have the potential to displace that plant in line with the expected marginal cost. If this is the case, they will service some of the load under the load duration curve.

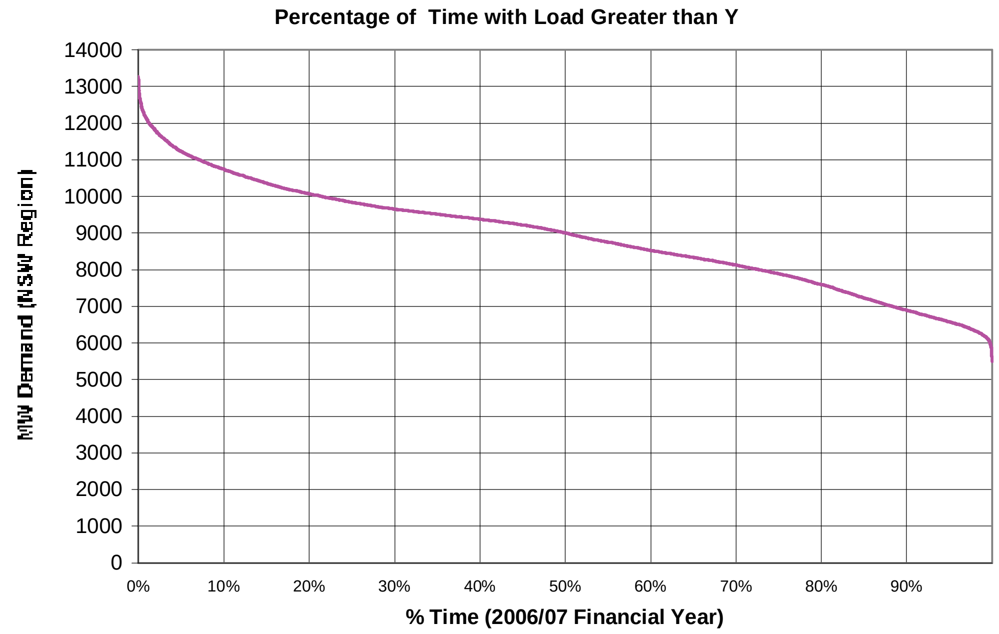

Figure 7.1 Load Duration for NSW Region July 2006 to June 2007

Modelling using reliability and market data could provide an indication of how the existing and proposed new plant might perform within the system. However such modelling is beyond the scope of this report. Consequently the marginal pricing approach has been taken.

Considering Figure 7.1 the maximum demand for the year was approximately 13,300 MW and the minimum approximately 5,500 MW. The energy sent out, simply calculated by multiplying demand by time, was approximately 78,000 GWh for the year. During July 2007, which is not included in the above data, the maximum demand reached approximately 13,900 MW. Given that NSW could have either a summer or winter peak, depending on the vagaries of the season, the current maximum demand could be considered to be approximately 14,000 MW.

It can be seen from this curve that for approximately 70% of the time the load was above 8000 MW and very close to 100 % of the time it was above approximately 6,000 MW. This means that more than 6,000 MW must be supplied at virtually all times.

Any new base load power plant must also be able to compete on marginal price if it is to operate into the NEM system. This may have a low marginal cost of generation and be very competitive in other respects or it may have a contractual arrangement that effectively gives it a zero marginal price. The price duration curve, Figure 7.2, is relevant as it shows the percentage of time that the pool price is above a particular amount and consequently the amount of time when a plant would operate, based on marginal cost. Figure 7.2 is based on the same set of data as the load duration curve, shown in the previous figure.

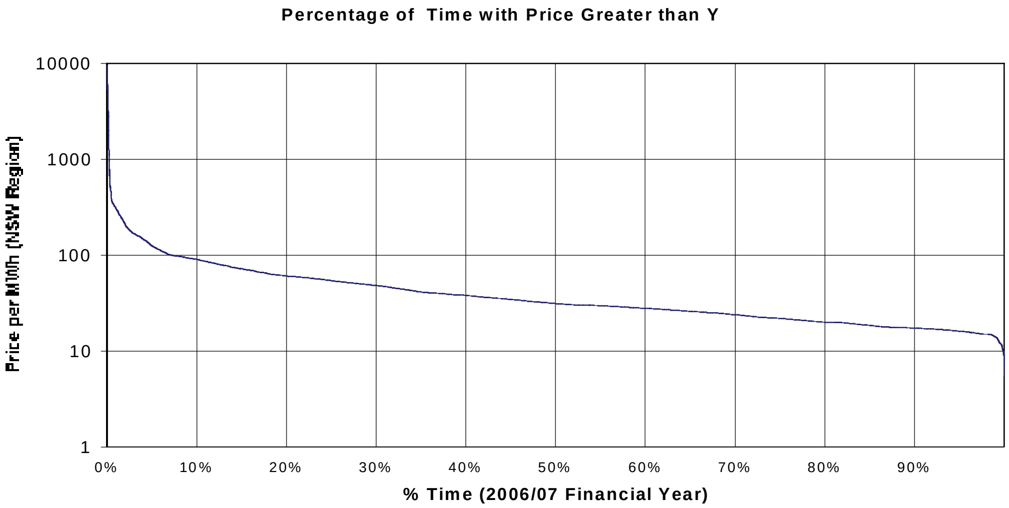

Figure 7.2 Price Duration Curve for NSW between July 2006 and June 2007

From this curve for example it can be seen that for about 7% of the time the price was above \$100/MWhr. This means that for only 7% of the time in a year a plant with a cost of more than \$100/MWhr would be called on to operate. The benefit for a plant (peaking or reserve) that operates in this area is that the price could be as high as \$10,000/MWh for some of that time. As a consequence, any plant that is targeting this must be able to operate reliably, as the opportunities are few. The risk for the peaking plant is that it is not scheduled because demand is met exclusively by lower cost plant.

Figure 7.3 shows a portion of the same price duration curve up to \$140/MWh that is more relevant for intermediate and base load plant as they would need to operate considerably more than 10% of the time. It can be seen from this graph that a pool price greater than \$20/MWh occurs over 80% of the time.

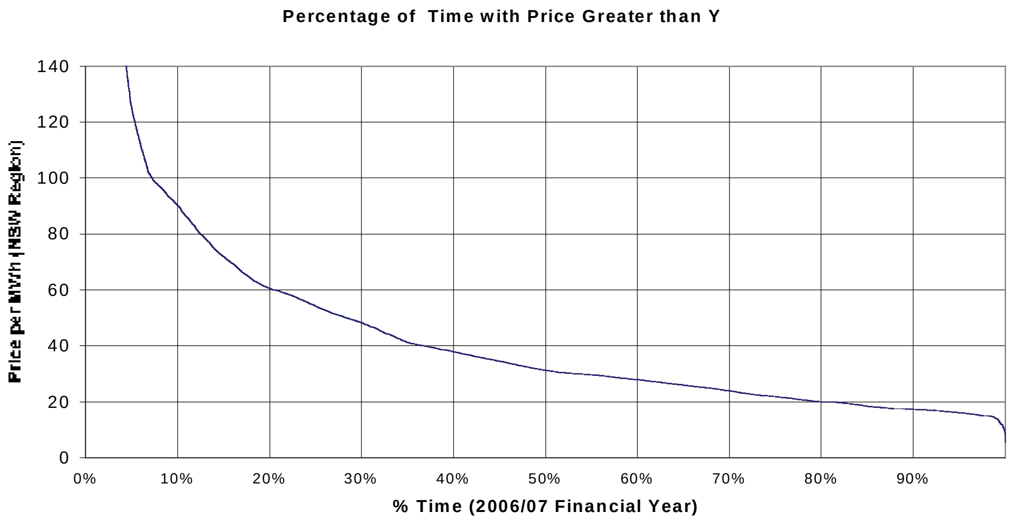

Figure 7.3 Price Duration Curve for NSW July 2006 to June 2007 for Prices less than 140/MWh

It can also be seen from the curve that plant with a marginal price of less than \$10/MWh will be called on virtually every time they are bid into the electricity market.

In order to assess how the new technologies may fit into the system they have been listed in Table 7.2 in order of marginal cost. Only those that are considered as a technically viable (Nuclear may not be regulatory viable) proposition within the next three years have been listed to simplify assessment. Any plant using renewable energy that is installed would be viable and would be in the same position as wind or biomass as it could normally be expected that the marginal price would be close to or at zero.

Technology	Marginal price $/MWh(SO)	Parasitic Load	Capacity Factor	EFOR	Dispatach -able	Name plate rating MW	Contribution to demand MW	Approx. Energy GWh/a
Wind	0	0%	35%	3%	No	750	40	2200
Biomass Thermal	0	5%	60%	5%	Yes	100	95	500
Coal USC	10	5%	90%	3%	Yes	1000	950	7000
Nuclear	5	5%	90%	3%	Yes	1000	950	7000
IGCC	13	10%	80%	5%	Yes	1000	900	6000
Natural gas CCGT	28	3%	90%	3%	Yes	800	776	6000

Table 7.2 New Technologies and Marginal Price

It should be noted that all are less than $30/MWh (SO) and that this price or greater occurs more than 50% of the time. Therefore, provided the overall financials for one of these power plants is viable, they would be dispatched as base load plant most of the time based on the marginal cost above.

Comparing hypothetical estimates for new plant electricity costs to those for existing plant that are more likely to be closer to real costs or prices needs to be done from a broad perspective. Table 7.3 lists the NSW plant and proposed projects, some of which are in the development phase, with their marginal cost (ACIL Tasman).

Station	Nominal Output MW	Marginal Cost $/MWh(SO) (ACIL 2007)
Appin /Tower	94	0.0
Wind	16	0.0
Biomass	60	0.0
Smithfield	160	0.0
Bayswater	2760	11.6
Redbank	150	11.7
Liddell	2080	12.4
Vales Point	1320	15.3
Eraring	2640	15.8
Mt Piper	1320	16.3
Munmorah	600	17.0
Wallerawang	1000	17.6
Tallawarra	440	29.6
Import Snowy (approx)	3200	
Import QNI(approx)	1100	
Import Direct Link (approx)	170	
Uranquinty GT	600	55.0
Munmorah GT	660	70.0
Kangaroo Valley	240	
Eraring GT	40	290.0
Hunter Valley GT	50	300.0
Total Potential	18379	

Table 7.3 Main Existing Plant Serving NSW and Marginal Price

Due to the nature of this data it has to be treated as a guide only, rather than definitive prices. However it does provide an indication of the position relative to base load plant in NSW.

The other factor that needs to be considered is the amount of energy that is required and can be generated. Considering Table 8.7 it can be seen that the coal fired power stations in NSW can provide around 70,000 GWh from 07/08 with some growth in energy output each year thereafter. This output would also be supported by supply through the interconnectors from Queensland and Snowy/Victoria, depending on demand and price at the time. In 06/07 if the NSW coal fired power stations produced the 70,000 GWh, indicated for 07/08, it would have sufficed for around 93% of the time, see Figure 7.4

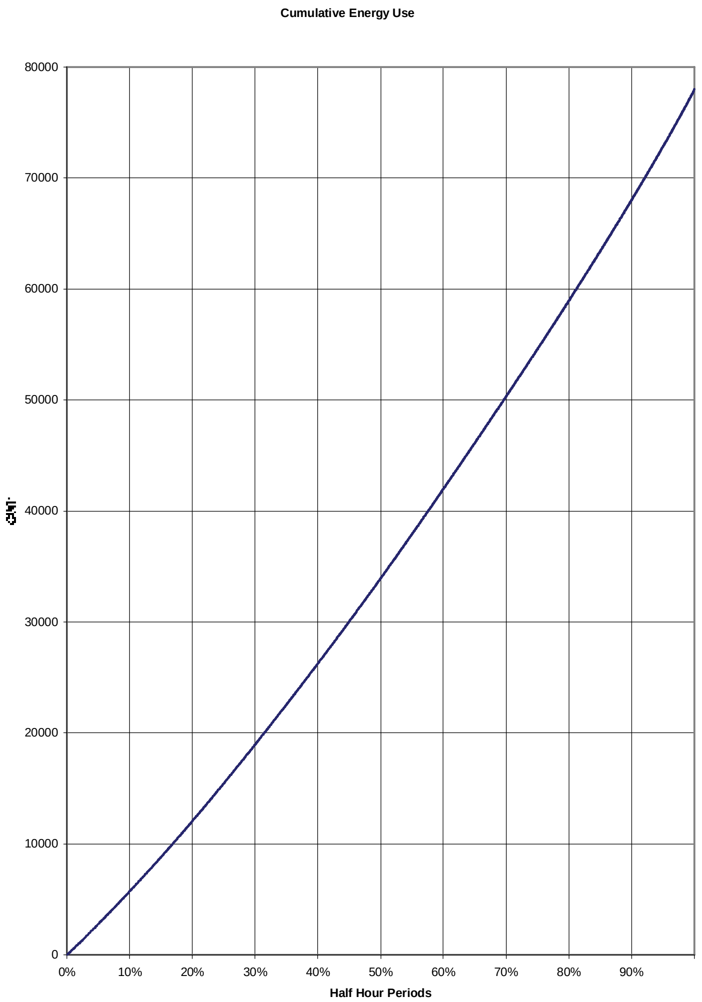

Figure 7.4 Cumulative Energy Time Curve.

Any plant that is installed, provided that it is dispatched, would serve to meet demand at the time and provide energy. Should say a 1,000 MW base load plant be installed it would operate for most of the time and contribute around 7,000 GWh and meet approximately 950 MW of the demand when it was operating. Renewable plant would also provide energy and meet demand in its operation. If the 1,000MW base load plant existed during 06/07 and was more competitive than most of the existing coal fired plant then the less competitive of those plant would not have operated as often.

It can be seen that the existing units in NSW can meet the energy requirements at the present time. Meeting demand is a slightly different matter, as at times it is likely that a number of base load units may be out of service due to a planned or forced outage and other units, possibly gas turbines would be required during that period.

It can also be seen that the proposed technologies, listed in Table 7.2, have the potential to displace existing coal fired plant, based on the marginal cost indicated. It should be noted that the marginal costs are from earlier sections in the report and that the lesser of the indicated costs has been used in Table 7.2. The competitiveness of new plant will ultimately depend on the contractual and/or fuel pricing arrangements that might be achieved. For example wind plant will displace all plant when it is generating and any coal plant that was built would need to be more competitive than most of the existing coal fired plant, otherwise it would not be built.

It can also be seen from the Price Duration curve that clearing prices greater than about $30/MWh occurred for about 50% of the time in 06/07. Furthermore, it can be seen in Figure 7.4 that 68,000 GWh was consumed in 90% of the time periods. Given that annual energy growth and annual demand growth each year are not the same it could be assumed that the new peak demand would be met by the gas turbine plant proposed to be installed for that purpose.

New base load plant would need to be able to bid into the NEM at less than $15/MWh to displace existing coal fired plant. Based on the 06/07 year and a price of $20/MWh the plant would have been dispatched more than 80% of the time, however this may not have been the case in previous years that were not impacted by the drought. Gas fired combined cycle plant may not have operated at capacity factors higher than about 40% to60% at a price of $28/MWh.

When an emissions trading scheme is introduced the marginal prices for plant using fossil fuel will change, altering their relative positions in the marginal price table and hence the relative competitiveness of the technologies. However it is beyond the scope of this report to consider the implications of that event.

Appropriate system modelling would be required to determine the capacity and duty of plant that might be installed in NSW. This could take into account plant reliability and the probability of outages as well as expected changes to fuel price and/or carbon emissions costs.

8. Characteristics of Existing NSW Generation Facilities

Deliverable 3 of this study involves the review of the characteristics of existing base and intermediate load generation plant. The following sections present the characteristics of the plants and attempts to consolidate the information provided into an overall summary of the NSW generating system capability over the next decade.

8.1 Overview of NSW Base and Intermediate Load Generators

Information was received from the four largest NSW electricity generating companies regarding the characteristics of their base load and intermediate generation plant. The information sought included:

1	Greenhouse gas co-efficients	kg/MWh(SO)	Coefficient required at MCR for each unit - current values
2	Available MCR for each unit	MW	Identify any restrictions (seasonal / climatic / other)
3	Expected forced outage rates	%	EFOR for each unit. Expected values either yearly or monthly for next 10 years
4	Expected planned outages		For each unit, planned outage dates for next 10 years
5	Technical capacity factor and / or energy output limits		Over next 10 yrs, technical capacity factor or monthly energy production limit for each unit
5	Major refurbishment requirements and timeframes		Identify planned upgrades or refurbishments
6	Performance following upgrade / refurbishment		Provide revised values of items 1 ,2, 3 & 5 following any upgrade or refurbishment

8.2 Delta Electricity

Delta provided the requested information on four of their facilities: Mt Piper, Vales Point, Wallerawang and Munmorah. The only information provided for the two bagasse fired plants was greenhouse coefficient and available MCR as these plant are still under construction.

Table 8.1 provides a summary of Connell Wagner's assessment of the data provided by Delta:

Plant	No. Units	MCR / unit	Average EFOR	Technical Capacity Factor	kg CO_2/MWh(SO)
Mount Piper	2	660	0.5%	90%	860
Vales Point	2	660	5%	75%	920
Wallerawang	2	480	3%	75%	940
Munmorah	2	300	10%	<20%	1065
Condong & Broadwater	2	30	n/a	n/a	0

Table 8.1 Summary of Delta Electricity Generating Plant

Comments on the data provided by Delta include:

- Historical performance of the plants being used as a guide to future performance may be appropriate for Mt Piper, with an average EFOR of 0.5%. However Wallerawang displayed a steady deterioration in EFOR between 2001 and 2006, and may be expected to continue to deteriorate into the future. Unit 7 was commissioned in 1976 and unit 8 in 1980. The 10% EFOR average for Munmorah is considered to be a reasonable based on its present condition and for units approaching 40 years of age.
- The capacity factors provided for the four stations appear reasonable. Mount Piper 90%, Wallerawang 75%, Vales Point 75%, Munmorah <20%. However over the next 10 years there may be expected to be a decrease in Mount Piper capability as it becomes older.
- The available MCR of Wallerawang at 480MW appears reasonable, although 500MW is available with increased boiler erosion. Therefore for short periods, 500MW would be available.

Major refurbishment may include the upgrade of Mt Piper units to 700MW in 2008/09 and the restoration of Munmorah units to 350MW at a time to be determined. If Munmorah units are refurbished, it could be expected that a greenhouse emission coefficient of about 860kg/MWh is achievable. This is similar to the present Mt Piper performance and is considered reasonable.

Outage durations for each Delta unit are in-line with good industry practice.

8.3 Eraring Energy

Eraring Energy provided data on their one coal fired power plant. No data was provided on any of the hydro assets. Connell Wagner's assessment of this information is summarised in Table 8.2.

Plant	No. Units	MCR / Unit	Average EFOR	Technical Capacity Factor	kg CO_2/MWh(SO)
Eraring (current)	4	660	3%	75 to 90%	890
Eraring (post upgrade)	4	720	3%	75 to 90%	880

Table 8.2 Summary of Eraring Energy Coal Fired Generating Plant

Eraring Energy has upgrades planned for all 4 units at Eraring. The upgrades may result in the available MCR increasing from 660 to 720MW. The 720MW capability is expected to be available from unit 3 in 2009/10, from units 1 and 2 in 2010/11 and from unit 4 in 2011/12. The upgrade will result in a slightly higher sent out efficiency and will reduce the greenhouse emissions intensity.

Comments on the data provided by Eraring Energy include:

- The Effective Forced Outage Rate (EFOR) is higher than could be expected for the near term. An output restriction caused by a cooling water discharge temperature issue has been factored into the EFOR values provided.
- An attemperating reservoir is planned to be installed by the end of 2008 which will allow the full output of the station to be achieved for at least 6 hours per day.
- Technically the station should be able to achieve a capacity factor of about 90% subject to management of environmental impacts on Lake Macquarie. It is our understanding that Eraring is currently investigating these issues as part of the upgrading process. However, in the past higher fuel costs at Eraring, compared to say Bayswater or Mt Piper, have meant that Eraring has had to reduce output at times of low electricity demand more regularly than some other NSW plant. This could continue into the future and hence a full 90% capacity factor performance may not be feasible at Eraring.
- Outage durations for each Eraring unit are in-line with good industry practice

8.4 Macquarie Generation

Macquarie Generation provided very comprehensive information on Bayswater and Liddell power station projected performance levels. Connell Wagner's assessment of the information is summarised in Table 8.3

Plant	No. units	MCR / unit	Average EFOR	Technical Capacity Factor	kg CO_2/MWh(SO)
Bayswater	4	690	2%	90%	895
Liddell (current)	4	515	7%	74%	950
Liddell (post upgrade)	4	525	7%	74%	920

Table 8.3 Summary of Macquarie Generation Generating Plant

The data provided by Macquarie Generation shows the Bayswater units as having an available MCR of 690MW from 1 July. No information was provided on the reason for the change in MCR.

Macquarie Generation is in the process of upgrading the Liddell units. The units have a nameplate rating of 500MW, however units 2 and 3 have been upgraded to 525MW. Unit 1 is planned for upgrade to 525 MW in 2009/10 and unit 4 in 2008/09. The efficiency improvement associated with the upgrade will result in a reduction in greenhouse intensity.

Comments on the data provided by Macquarie Generation include:

– The EFOR values for Bayswater appear reasonable.

– The Liddell EFOR of 7% appears to be appropriate for a plant of Liddell's age and consistent with other similar aged plant in NSW.

– Outage durations for Macquarie Generation plant are in-line with good industry practice.

8.5 Snowy Hydro

Data provided by Snowy Hydro is summarised in Table 8.4.

Plant	No. Units	MCR / Unit	Average EFOR	Technical Capacity Factor	kg CO_2/MWh(SO)
Guthega	2	30	<0.5%	23%	0
Tumut 1	4	82	<0.5%	28%	0
Tumut 2	4	72	<0.5%	29%	0
Tumut 3	6	250	<0.5%	4%	0
Blowering	1	80	<0.5%	24%	0
Murray 1	10	95	<0.5%	16%	0
Murray 2	4	137.5	<0.5%	16%	0

Table 8.4 Summary of Snowy Hydro Generating Plant

Snowy Hydro made a number of qualifications regarding the values presented in Table 8.4:

– The available MCR capacities are subject to head pond levels.

– Capacity factors are conservative as they are based on past 10 years (including droughts).

Information provided regarding unit upgrades included:

– A 5 year program has been commenced to upgrade Tumut 3 to have a total capacity of 1650 MW

– Plan to upgrade Murray 2 from 550 MW to 610 MW. within the next 10 years

Outage data was not available from Snowy Hydro. However as plant capacity factors average only around 15%, there would be no impact of outages on the energy calculations performed below.

8.6 Overall Maximum Capacity Factor Summary

Table 8.5 summarises the capacity factors for the major power stations in NSW taking into consideration the data provided by the generators. The capacity achieved by stations depends on many factors including technical, environmental, their performance in the National Electricity Market and the aging of the stations. Consequently the outcome from year to year will vary and it is unlikely the maximum capacity factors for all of the stations could be achieved in any year. It is not possible to predict the future performance in great detail and the data provided needs to be considered in that light.

Station	Nameplate Output MW	Maximum Estimated Capacity Factor % ##
Bayswater	2640	90
Liddell	2000	74
Mt Piper	1320	90
Wallerawang	1000	75
Vales Point	1320	75
Munmorah	700	25
Eraring	2640	90 **
Guthega	60	24
Upper Tumut	600	30
Lower Tumut	1500	4
Blowering	80	24
Murray 1	950	15
Murray 2	550	15

** Eraring Capacity Factor is subject to assessment of the environmental impact on Lake Macquarie and realistic loading constraints ##These capacity factors are subject to many operational factors. There is a significant risk that all plant may not achieve maximum capacity factors coincidently

Table 8.5 Summary of Current Nameplate Outputs and Maximum Estimated Capacity Factors

8.7 Future NSW Generation Capability

8.7.1 Methodology

The data provided by the four generators was amalgamated into a single spreadsheet, to allow a composite picture of the NSW generation capability to be obtained. The results are presented on the following bases:

i) Capacity (MCR) basis (MW)

ii) Annual energy production basis (GWh)

The presentation of results on a capacity basis allows the total capacity from the specified units to be obtained, taking into account proposed plant upgrades. However a shortcoming of this approach is that the older plants with EFOR values approaching 10% have a finite probability of not being available to deliver capacity at a particular point in time. As a Monte-Carlo simulation of the system is beyond the scope of this study, results have also been presented on an annual energy production basis. This approach allows the probability of a forced outage to be included by mathematically including the EFOR in the energy calculation.

For each unit in the system, the following calculation was performed for each year between 2007/08 and 2016/17:

Annual energy capability (MWh/annum) =
*[MCR capability] * [technical capacity factor]* [100-EFOR]*[(365-outage days)/365]*8760hrs*

The annual energy capability therefore considers actual MCR capability, capacity factor, forced outage rate and planned outages.

8.8 Future NSW Capacity Capability

The theoretical NSW electricity production capability from coal fired plant and Snowy Hydro plants is summarised in Table 8.6. Detailed unit ratings compiled from the NSW generator data is tabulated in Appendix C.

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Mt Piper	1320	1400	1400	1400	1400	1400	1400	1400	1400	1400
Munmorah ##	600	600	600	600	600	600	600	600	600	600
Vales Point	1320	1320	1320	1320	1320	1320	1320	1320	1320	1320
Wallerawang	960	960	960	960	960	960	960	960	960	960
Eraring	2640	2640	2700	2820	2880	2880	2880	2880	2880	2880
Liddell	2080	2090	2100	2100	2100	2100	2100	2100	2100	2100
Bayswater	2760	2760	2760	2760	2760	2760	2760	2760	2760	2760
	11680	11770	11840	11960	12020	12020	12020	12020	12020	12020
Snowy Hydro**	3756	3795	3820	3845	3870	3895	3920	3920	3920	3920
TOTAL**	15436	15565	15660	15805	15890	15915	15940	15940	15940	15940

** Not all of the Snowy output can be exported to NSW and the extent of import will be governed by market forces and the capacity of the interconnectors. Snowy power is exported to both NSW and Victoria and may go either way depending on the market circumstances. ## In their submission to the Owen Inquiry Delta Electricity indicated that significant expenditure would be required on Munmorah if it is to avoid being retired in 5 years (about 2012).

Table 8.6 Annual Capability of NSW Thermal and Snowy Hydro Plants (MW)

A number of assumptions have been made in assembling this data:

– All MW values are based on the MCR values provided by the generators. As older plant may have EFOR values of between 5 and 10%, there is a finite probability that at a given time some of the capacity will not be available.

– As the Snowy Hydro plants have capacity factors of between 4 and 29%, a significant proportion of the capacity is resource constrained.

– In accordance with the data provided by the generators, no plant retirements have been factored into the analysis.

– The proposed change in rating of the Munmorah units from 300 to 350 MW has not been included as dates for the upgrade were not available from Delta Electricity.

– The 5 year program to upgrade Tumut 3 from 1500MW to 1650MW has been assumed to occur between 2008/09 and 2013/14.

– The Jounama 14MW Hydro is assumed to be operational in 2008/09.

The plants included in the analysis presented graphically in Figure 8.1 only covered those operated by the four major generators. Therefore plant such as Redbank, Smithfield, Tower, Appin and small hydro, biomass and wind have not been included.

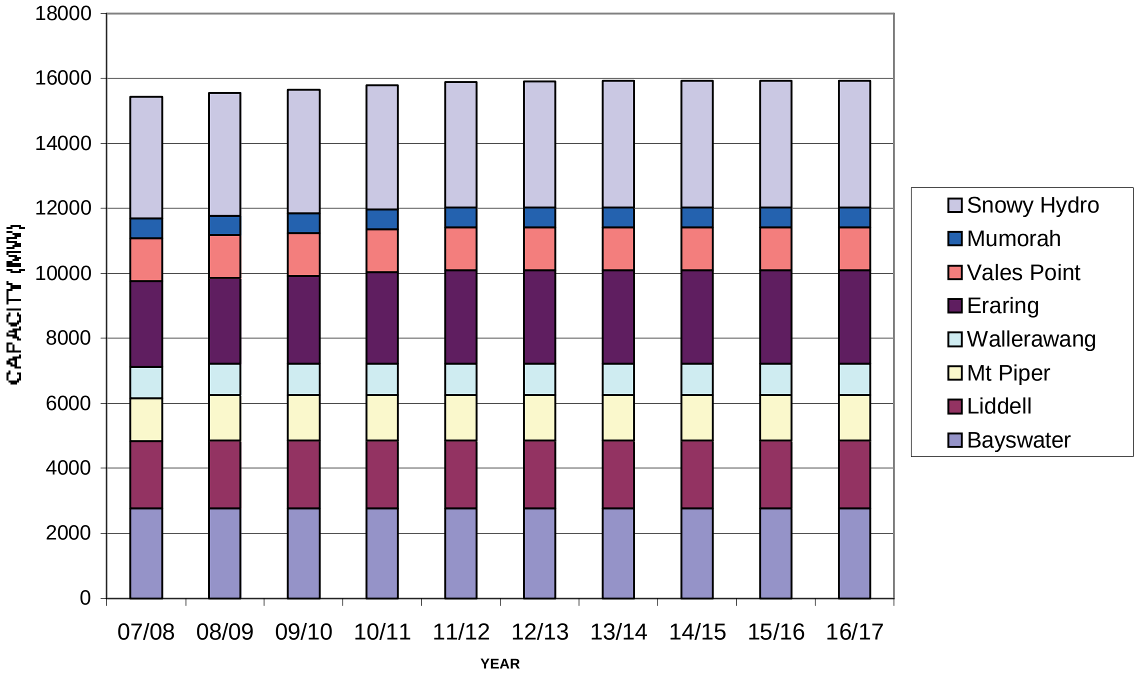

Figure 8.1 Annual Capability of NSW Major Thermal and Snowy Hydro Plants (MW)

A few observations can be made from the above data:

– With the proposed thermal plant upgrades (Eraring, Mt Piper, Liddell), there will be an additional 340MW of capability by 2011/12

– Additional capacity arising from the Snowy Hydro upgrades can be constrained by transmission system limitations towards Sydney

8.9 Future NSW Energy Capability

The above methodology was adopted to compute the annual energy capability of each thermal and Snowy Hydro unit in the system. The detailed analysis is provided as Appendix C.

Table 8.7 provides a summary of the annual expected energy capability of each power plant provided by the power stations.

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Mt Piper	10061	9301	10987	10566	10460	10460	10776	10776	9933	9933
Munmorah	705	749	719	749	720	749	719	749	713	719
Vales Point	7263	8147	8067	7745	7826	8147	8067	7745	7826	8147
Wallerawang	5925	5633	5633	5925	5691	5633	5282	5984	5867	5574
Eraring	19781	19302	18573	20780	22264	22022	21589	21817	21797	21797
Liddell	11124	11309	11657	11657	11657	11657	11657	11657	11657	11657
Bayswater	20848	20511	20408	20950	20950	20511	20950	20950	20511	20950
Snowy Hydro**	4433	4442	4452	4461	4470	4480	4489	4489	4489	4489
TOTAL	80140	79395	80496	82834	84040	83660	83530	84169	82794	83268

**Not all Snowy Hydro energy is necessarily available to supply NSW.

Table 8.7 Annual Energy Capability of NSW thermal and Snowy Hydro Plants (GWh)

A number of points may be noted from Table 8.7:

– Snowy Hydro can provide about 20% of the peak demand in NSW (approximately 14,000 MW) and about 5% of the energy requirements. The full output of Snowy is shared between NSW and Victoria.

As Delta Electricity have not predicted any change in EFOR for Munmorah, Vales Pt or Wallerawang over the next 10 years, projected energy production is relatively constant. However, given the age of these plants a decrease in reliability and energy production capability would be expected.

9. Summary

The foregoing chapters have

- Identified a range of prospective generation technologies,
- Identified potential carbon capture and disposal technologies,
- Discussed the applicability of the technologies to the NSW operating environment,
- Considered the performance and capability of existing NSW base load generation.

The findings of these areas are summarised below:

9.1 Identification of Prospective Generation Technologies

A number of non-renewable and renewable technologies were identified as being potentially suitable for the provision of base load electricity production in NSW. These have been identified in Table 9.1 as those being available in 2007 and those not being commercially available until some date in the future.

Technology	Commercial Operation	Construction Cost $/kW	Fuel Cost $/MWh(SO)	CO_2 kg/MWh(SO)
Ultra-supercritical coal (USC)	currently available	1400 - 1950	8 - 14	785-860
USC with CCS	CCS available 2020	3000 - 3500	11 - 20	~ 100
Natural Gas Combined Cycle	currently available	800 - 940	>28	345
CCGT with CCS	CCS available 2020	1300 – 1700	>33	~ 50
IGCC	2015	2100 – 2600	9 - 14	785 - 840
IGCC with CCS	CCS available 2020	3100 - 3500	9 - 16	~ 100
Nuclear	Currently available but no regulatory regime	2800 – 3000	5	0
Solar Thermal	Currently available but in early phase	~ 4600	0	0
Hot dry rocks	unknown	unknown, site specific	0	0
Hydro	Currently available	site specific	0	0
Biomass thermal	Currently available	2000	0* - 30	0

Table 9.1 Summary of Prospective Generation Technologies
[see text for references.* depends on fuel source]

In addition to the above, technologies such as wind, which is predominantly unscheduled generation, do contribute to energy supply.

9.2 Carbon Capture and Disposal Technologies

Chapters 5 and 6 identified a number of carbon dioxide capture and disposal technologies. All of the technologies are at an early stage of development for base load power generation and cost estimation is difficult. Cost data has been included for three of the non-renewable technologies presented in Table 9.1.

Potential carbon capture technologies are identified in Table 9.2a and a generic list of storage technologies covered in Table 9.2b.

Capture Type	Technology	Status of Development
Post Combustion	chemical absorption - amine	economically feasible under specific conditions
	chemical absorption - chilled ammonia	demonstration phase
	membrane separation	research phase
	solid sorbent	research phase
	cryogenic	economically feasible under specific conditions
Oxy- Fuel Combustion		demonstration phase
Pre- Combustion	physical absorption - Selexol	economically feasible under specific conditions
	physical absorption - Rectisol	economically feasible under specific conditions

Table 9.2a. Potential Carbon Dioxide Capture Technologies

Storage Type	Technology	Status of Development
Geological	Depleted oil & gas reservoirs	economically feasible under specific conditions
	Enhanced oil recovery	economically feasible under specific conditions
	Deep saline formations	demonstration phase
	Deep unminable coal beds	research phase
	Enhanced coal bed methane recovery	demonstration phase
Ocean Storage	Pipeline	research phase
	CO_2 lake fed by ship	research phase
	Water column release	research phase
Stable Carbonate		research phase

Table 9.2b. Potential Carbon Dioxide Storage Technologies

9.3 Applicability of Technologies to NSW

An assessment of the expected marginal generation cost of the prospective base load technologies was made with respect to the NSW load duration curve (Figure 7.3). This analysis found that the following technologies (Figure 9.3) may be applicable to the NSW operating environment:

Technology	Capacity Factor	Name plate rating MW	Contribution to demand MW	Energy GWh/a	Fuel cost $/MWh(SO)
Wind	35%	750	40**	2200	0
Biomass Thermal	80%	100	95	700	0 -30
Coal USC	90%	1000	950	7000	8 - 14
Nuclear	90%	1000	950	7000	5
IGCC	80%	1000	900	6000	9 - 14
Natural gas CCGT	90%	800	776	6000	>28

** This represents the approximate contribution to peak with a 95% availability

Figure 9.3 Applicability of Technologies to NSW Operating Environment

9.4 Existing NSW Generation Facilities

Chapter 8 includes an analysis of the characteristics of existing NSW generation facilities. This analysis estimated the generation capability and energy capability over the next decade. A summary is provided in Table 9.4.

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Coal capability (MW)	11680	11770	11840	11960	12020	12020	12020	12020	12020	12020
Snowy Hydro capability (MW) *	3756	3795	3820	3845	3870	3895	3920	3920	3920	3920
TOTAL**(MW)	15436	15565	15660	15805	15890	15915	15940	15940	15940	15940
Coal energy	75707	74953	76044	78373	79570	79180	79041	79679	78304	78779
Snowy Hydro energy **	4433	4442	4452	4461	4470	4480	4489	4489	4489	4489
TOTAL (GWh)	80140	79395	80496	82834	84040	83660	83530	84169	82794	83268

* Snowy to NSW transmission link is limited to about 3000 MW.

** Snowy power is exported to both NSW and Victoria and the quantity that can be exported to NSW will be governed by market forces and the capacity of the interconnectors.

Table 9.4 Projected NSW Power Generation and Energy Production Capability.

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11. Glossary

Bagasse	Biomass remaining after sugarcane stalks are crushed to extract their juice
CCGT	Combined cycle gas turbine
CCSD	CRC for Coal and Sustainable Development
CLFR	Compact Lineal Fresnel Reflector
EFOR	effective forced outage rate
EPRI	Electric Power Research Institute (USA)
FOAK	First of a kind (technology)
FWHR	Feed water heater repowering
GT	Gas turbine
HHV	Higher Heating Value
HLW	High level waste (nuclear)
HRSG	heat recovery steam generator
IAEA	International Atomic Energy Agency
IGCC	Integrated Gasification Combined Cycle
IPCC	Intergovernmental Panel on Climate Change
LCOE	levelised cost of electricity
MCR	maximum continuous rating
MEA	Monoethanolamine
MW	mega Watt
NOx	Nitrogen oxides
ORER	Office of the Renewable Energy Regulator
PPA	Power purchase agreement
SEDA	Sustainable Energy Development Authority (NSW)
SOx	Sulphur oxides
SO	Sent Out
STE	Solar Thermal Energy
UCC	Ultra clean coal
USC	Ultra-supercritical

Appendix A

NSW Renewable Generation

NSW Hydro Schemes (RISE, 2007)

Project	Owner	Installed MW
1. Snowy Mountains Hydro-Electric Scheme		
Tumut 3	Snowy Hydro	1500
Murray 1	Snowy Hydro	950
Murray 2	Snowy Hydro	550
Tumut 1	Snowy Hydro	329.6
Tumut 2	Snowy Hydro	286.4
Blowering	Snowy Hydro	80
Guthega	Snowy Hydro	60
Subtotal		3756
2. Other Hydro Schemes		
Bendeela	Eraring Energy	80
Hume	Eraring Energy	58
Warragamba	Eraring Energy	50
Copeton	Meridian Energy Australia	22.5
Burrendong	Meridian Energy Australia	19
Wyangla Dam	Hydro Power	18
Burrinjuck II	Eraring Energy	16
Burrinjuck I	Eraring Energy	12
Mullumbimby	Country Energy	10
Namboida	Country Energy	9.8
Hume II	Eraring Energy	7.5
Williams Dam	Publicly Owned	7
Kembla Grange	General Water Australia	6.4
Keepit	Eraring Energy	6
Pindari	Meridian Energy Australia	6
Glenbawn Dam	Meridian Energy Australia	5.5
Oaky River Dam	Country Energy	5
Brown Mountain	Eraring Energy	4
Jindabyne	Snowy Hydro	2
Mulwala Canal	Pacific Hydro	2
Tumut 3 (mini)	Snowy Hydro	0.84
Plashett	Snowy Hydro	0.8
Googong Dam	ActewAGL	0.6
Mount Piper	Delta Electricity	0.355
Dungog	Delta Electricity	0.35
Mannus Lake	Private	0.3
Chichester Dam	Delta Electricity	0.11
Yarrangobilly Caves	Unknown	0.08
Toonumbar	Rous County Council	0.065
Subtotal		350

NSW Biomass Plants (ORER, 2007)

Name	Owner	Fuel Type	Installed MW
Broadwater	NSW Sugar Mills Co-Op	Biomass (bagasse)	8
Condong	NSW Sugar Mills Co-Op	Biomass (bagasse)	3
Harwood	NSW Sugar Mills Co-Op	Biomass (bagasse)	4.5
Camellia	EarthPower Technologies	Biomass (digester gas)	3.5
Awaba	LMS Generation Pty Ltd	Biomass (landfill methane)	1.1
Belrose	Energy Developments Ltd	Biomass (landfill methane)	4
Jacks Gully	Energy Developments Ltd	Biomass (landfill methane)	1
Lucas Heights I	Energy Developments Ltd	Biomass (landfill methane)	4
Lucas Heights II	Energy Developments Ltd	Biomass (landfill methane)	9
Nowra	AGL	Biomass (landfill methane)	1
Stotts Creek	Landfill Management Services Pty Ltd	Biomass (landfill methane)	0.4
Whytes Gully	Energy Developments Ltd	Biomass (municipal waste)	2.5
Cronulla	Sydney Water	Biomass (sewage methane)	0.5
Malabar	Sydney Water	Biomass (sewage methane)	3
Bayswater	Macquarie Generation	Biomass (woodwaste)	5
Big River	Big River Timbers Pty Ltd	Biomass (woodwaste)	0.45
Liddell	Macquarie Generation	Biomass (woodwaste)	5
Mount Piper	Delta Electricity	Biomass (woodwaste)	5
Tumut	Visy Paper	Biomass (woodwaste)	17
Vales Point B	Delta Electricity	Biomass (woodwaste)	5
Wallerawang C	Delta Electricity	Biomass (woodwaste)	5
Condong	Sunshine Electricity	Bagasse	30 *
Broadwater	Sunshine Electriciyt	Bagasse	30*

*Under construction commissioning due 2007/2008

NSW Wind Projects

Name	Owner	Inatalled MW
Crookwell Wind Farm	Eraring Energy	5
Blayney Wind Farm	Eraring Energy	10
Hampton Wind Park	Litchfields	1.3
Kooragang Island Wind Project	Energy Australia	0.6

Appendix B

Prospective Generation Technologies

Technology	Capacity Factor (Approx)	Output Restrictions	Fuel Cost	Fuel Resource	Environmental	Water (Kg/MWh(SO))	Greenhouse Gas Emissions CO_2e	Maturity And Timeframe	Construction Cost	Project Delivery Risks	Suitability For Base load
SOLAR THERMAL	25% (without storage) 40% (with limited thermal storage)	Daytime	$0	No fuel required Renewable energy resource	Land use	Required for cooling but dry cooling an alternative	None from operation	Demonstration with several large plant in operation in USA 10 – years	$2,500 – 4,600/kW (Acciona, 2007)	Standard	Not currently, but possible with development.
BIOMASS THERMAL	50% +	May have seasonal for some resources	$0 to $10 Depends on fuel source location	Limited if using waste	Land use for fuel production	Required for cooling but dry cooling an alternative	Minor from operation provided fuel is renewable	Mature technology is available	$2000/kW	Standard	Yes, but some sources could be seasonal
WIND	30%	Variable and uncontrolled	$0	No fuel required Renewable energy resource	Visual	None Required	None in operation	Mature	$2000/kW	Standard	No
HOT DRY ROCKS	90% + (for mature technology)	None	$0	No fuel required (life of resource is unlimited in operation)	Land use	Required for cooling but dry cooling an alternative. May be required for make up	None from operation	Not mature There are no complete demonstration plants	Unknown in total and site specific	High risk as not demonstrated	Yes but untried
HYDRO	90% +	None. Weather major variable	$0	Limited by water supply in NSW and essentially none is available	Land use	Water is not evaporated in generating None is used	None from operation	Mature	Site specific	Standard	No major sites available in NSW
NATURAL GAS CCGT	90% +	None	>$25/MWh	Limited but some available	Land use air emissions	1000 (wet) 25 (dry)	390 t/GWh Capture may be possible	Mature	$800 - 840/kW	Standard	Yes
NATURAL GAS CCGT - CO_2 CAPTURE	90%	None	>$35/MWh(SO)	Limited but some available	Land use air emissions CO_2 disposal sites	greater than base	~50t/GWh	Mature generation; CCS not commercial until 2020	$1300 - $1700	Standard for generation; CCS technical risk	Yes But Carbon Capture not developed
COAL PF USC	90% +	None	$8 - 14/MWh(SO) (depends on coal source & cooling type)	Plentiful	Land use air emissions ash storage;	1800 (wet) 140 (dry)	785 - 820 t/GWh Capture may be possible	Mature	$1400 - $1950/kW	Standard	Yes
COAL PF USC with CO_2 CAPTURE	90%	None	$11 - $20/MWh(SO)	Plentiful	Land use air emissions ash storage; CO_2 disposal sites	greater than base	~100 t/GWh	Mature generation; CCS not commercial until 2020	$3000 - $3500/kW	Standard for generation; CCS technical and cost risk	Yes But Carbon Capture not developed
COAL IGCC	90% +	None	$8 – 14/MWh(SO)	Plentiful	Land use air emissions ash storage	2200 - 2300	785 - 820 t/GWh Capture may be possible and it can be designed to reduce capture costs	Commercial generation 2015	$2100 - 2600/kW	Technical risk high	Yes But in an early stage of development
COAL IGCC with CO_2 CAPTURE	90% +	None	$10 – 16/MWh(SO)	Plentiful	Land use air emissions ash storage; CO_2 disposal sites	greater than base	~100 t/GWh	Commercial generation 2015; CCS not commercial until 2020	$3100 - $3500/kW	Technical risk high, CCS technical and cost risk	No No complete viable demonstration yet available
UCG COAL CCGT	90% +	None	$19 - 24/MWh(SO)	Plentiful	Land use air emissions, ash storage, aquifer pollution from fuel production.	Significantly higher than natural gas combined cycle	770 t/GWh Capture may be possible	Not mature and unproved	Unknown	Technical risk very high, fuel process risk	NO It has not been demonstrated here yet
NUCLEAR	90% +	None	$5/MWh(SO)	Plentiful (in Australia)	Land use, Waste storage	Required for cooling but dry cooling an alternative or can be on site near water (location not constrained by fuel resources)	None from operation	Mature	$2500 - $3300/kW	Standard, cultural Spent fuel Reception	YES But no regulatory regime

Appendix C

Future NSW Generation Capability

Outage Days Per Year

Delta Electricity	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Mount Piper Unit 1	0	56	0	14	0	35	0	14	0	70
Mount Piper Unit 2	21	56	0	14	35	0	14	0	70	0
Munmorah Unit 3	42	14	14	14	42	14	14	14	49	14
Munmorah Unit 4	28	14	42	14	14	14	42	14	14	42
Vales Point Unit 5	84	7	14	14	42	7	14	14	42	7
Vales Point Unit 6	14	14	14	42	7	14	14	42	7	14
Wallerawang unit 7	7	49	7	14	7	42	14	7	14	49
Wallerawang unit 8	14	7	49	7	42	14	84	7	14	14
Eraring Energy										
Eraring 1			85			14		42		
Eraring 2	28		91			14			42	
Eraring 3		91			14		42			
Eraring 4	28	0		86			14			42
	56	91	176	86	14	28	56	42	42	42
Macquarie Generation										
Liddell unit 1	52	50	44	16	44	16	44	16	44	16
Liddell unit 2	16	44	16	44	16	44	16	44	16	44
Liddell unit 3	16	44	16	44	16	44	16	44	16	44
Liddell unit 4	86	16	44	16	44	16	44	16	44	16
Bayswater unit 1	0	30	0	30	0	0	30	0	0	30
Bayswater unit 2	0	0	37	0	0	30	0	0	30	0
Bayswater unit 3	37	0	30	0	0	30	0	0	30	0
Bayswater unit 4	0	30	0	0	30	0	0	30	0	0

NSW Unit Capacity vs Time

	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Delta Electricity										
Mt Piper 1	660	700	700	700	700	700	700	700	700	700
Mt Piper 2	660	700	700	700	700	700	700	700	700	700
Munmorah 3	300	300	300	300	300	300	300	300	300	300
Munmorah 4	300	300	300	300	300	300	300	300	300	300
Vales Pt 5	660	660	660	660	660	660	660	660	660	660
Vales Pt 6	660	660	660	660	660	660	660	660	660	660
Wallerawang 7	480	480	480	480	480	480	480	480	480	480
Wallerawang 8	480	480	480	480	480	480	480	480	480	480
Eraring										
Eraring 1	660	660	660	720	720	720	720	720	720	720
Eraring 2	660	660	660	720	720	720	720	720	720	720
Eraring 3	660	660	720	720	720	720	720	720	720	720
Eraring 4	660	660	660	660	720	720	720	720	720	720
Macgen										
Liddell 1	515	515	525	525	525	525	525	525	525	525
Liddell 2	525	525	525	525	525	525	525	525	525	525
Liddell 3	525	525	525	525	525	525	525	525	525	525
Liddell 4	515	525	525	525	525	525	525	525	525	525
Bayswater 1	690	690	690	690	690	690	690	690	690	690
Bayswater 2	690	690	690	690	690	690	690	690	690	690
Bayswater 3	690	690	690	690	690	690	690	690	690	690
Bayswater 4	690	690	690	690	690	690	690	690	690	690
TOTAL THERMAL (MW)	11680	11770	11840	11960	12020	12020	12020	12020	12020	12020

Guthega	60	60	60	60	60	60	60	60	60	60
Tumut 1	328	328	328	328	328	328	328	328	328	328
Tumut 2	288	288	288	288	288	288	288	288	288	288
Tumut 3	1500	1525	1550	1575	1600	1625	1650	1650	1650	1650
Blowering	80	80	80	80	80	80	80	80	80	80
Murray 1	950	950	950	950	950	950	950	950	950	950
Murray 2	550	550	550	550	550	550	550	550	550	550
Jounama	0	14	14	14	14	14	14	14	14	14
Total Snowy (MW) **	3756	3795	3820	3845	3870	3895	3920	3920	3920	3920

Total Thermal + Hydro (MW)	15436	15565	15660	15805	15890	15915	15940	15940	15940	15940

** Snowy output is shared between NSW and Victoria and the import to NSW is also dependent of the market price and the capacity of the interconnectors at the time.

Annual GWh Energy Production

(based on MCR, EFOR, CF and planned outage days)

	Max sustainable CF %	capability MCR (MW)	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Delta Electricity												
Mt Piper 1	90%	660	5180	4651	5494	5283	5494	4967	5494	5283	5494	4440
Mt Piper 2	90%	660	4882	4651	5494	5283	4967	5494	5283	5494	4440	5494
Munmorah 3	40%	300	337	366	366	366	337	366	366	366	329	366
Munmorah 4	40%	300	368	384	353	384	384	384	353	384	384	353
Vales Point 5	75%	660	3229	4114	4034	4034	3712	4114	4034	4034	3712	4114
Vales Point 6	75%	660	4034	4034	4034	3712	4114	4034	4034	3712	4114	4034
Wallerawang 7	75%	480	2992	2641	2992	2933	2992	2699	2933	2992	2933	2641
Wallerawang 8	75%	480	2933	2992	2641	2992	2699	2933	2348	2992	2933	2933
Eraring Energy												
Eraring 1	90%	660	5047	5047	3872	5535	5535	5295	5506	4873	5506	5506
Eraring 2	90%	660	4804	5203	3906	5676	5676	5459	5676	5676	5023	5676
Eraring 3	90%	660	5125	3848	5591	5591	5377	5591	4948	5591	5591	5591
Eraring 4	90%	660	4804	5203	5203	3977	5676	5676	5459	5676	5676	5023
Macquarie Generation												
Liddell 1	74%	515	2671	2688	2792	3036	2792	3036	2792	3036	2792	3036
Liddell 2	74%	525	3036	2792	3036	2792	3036	2792	3036	2792	3036	2792
Liddell 3	74%	525	3036	2792	3036	2792	3036	2792	3036	2792	3036	2792
Liddell 4	74%	515	2381	3036	2792	3036	2792	3036	2792	3036	2792	3036
Bayswater 1	90%	690	5347	4908	5347	4908	5347	5347	4908	5347	5347	4908
Bayswater 2	90%	690	5347	5347	4805	5347	5347	4908	5347	5347	4908	5347
Bayswater 3	90%	690	4805	5347	4908	5347	5347	4908	5347	5347	4908	5347
Bayswater 4	90%	690	5347	4908	5347	5347	4908	5347	5347	4908	5347	5347
TOTAL COAL	MWh		75707	74953	76044	78373	79570	79180	79041	79679	78304	78779
Snowy Hydro **												
Guthega	23.4%	60	122.4	122.4	122.4	122.4	122.4	122.4	122.4	122.4	122.4	122.4
Tumut 1	27.4%	328	783.3	783.3	783.3	783.3	783.3	783.3	783.3	783.3	783.3	783.3
Tumut 2	29.1%	288	730.5	730.5	730.5	730.5	730.5	730.5	730.5	730.5	730.5	730.5
Tumut 3	4.3%	1500	562.2	571.6	580.9	590.3	599.7	609.0	618.4	618.4	618.4	618.4
Blowering	24.4%	80	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1	170.1
Murray 1	15.9%	950	1316.6	1316.6	1316.6	1316.6	1316.6	1316.6	1316.6	1316.6	1316.6	1316.6
Murray 2	15.6%	550	747.8	747.8	747.8	747.8	747.8	747.8	747.8	747.8	747.8	747.8
Snowy	MWh	3756	4433	4442	4452	4461	4470	4480	4489	4489	4489	4489
TOTAL	MWh		80140	79395	80496	82834	84040	83660	83530	84169	82794	83268

** Snowy output is shared between NSW and Victoria and the import to NSW is also dependent of the market price and the capacity of the interconnectors at the time.

Owen Inquiry into Electricity Supply in NSW

Availability and Cost of Gas for NSW Baseload Generation

31st July 2007

Wood Mackenzie

Strictly Private and Confidential

This report has been prepared for the Owen Inquiry by Wood Mackenzie. The report is intended solely for the benefit of NSW Government and its contents and conclusions are confidential and may not be disclosed to any other persons or companies without Wood Mackenzie's prior written permission.

The information upon which this report is based has either been supplied to us by NSW Government or comes from our own experience, knowledge, and databases. The opinions expressed in this report are those of Wood Mackenzie. They have been arrived at following careful consideration and enquiry but, as of this date, are subject to change. We do not accept any liability for reliance on them by parties other than the NSW Government.

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31st July 2007

Executive Summary

- **There is a reasonable expectation that there are sufficient gas supply resources to support the long term gas-fired generation capacity additions in NSW.**
    - Gas reserves replacement ratio over the last 5 years in Eastern Australia has been a healthy 260%, with continued, strong CSG reserves additions expected in the medium term.
    - Potential exists for significant gas supply from within NSW (CSG) although at this stage material production is yet to be proven.
    - Higher gas prices will support further exploration and development of gas resources.
- **Additional pipeline capacity will be required to meet the growing gas demand in NSW.**
- **New gas fired-generation is marginally competitive with coal fired generation as baseload in NSW but only with the support of NGAC's. This is due to the relatively high delivered cost (commodity plus capacity costs) of gas to potential generation locations in NSW.**
- **With possible implementation of a Carbon Trading scheme, gas fired-generation (at 75% load factor) would be competitive with coal fired generation for baseload in NSW with a carbon price of A$15-$30/tonne CO_2 equivalent.**

Contents

1. Introduction

1.1 Study Scope

As part of the NSW Government inquiry into the need for and timing of base load electricity generation in NSW, (the "Owen Inquiry"), the option for gas fired generation is being assessed. In evaluating the suitability of this technology, the key aspects of gas supply availability and the forecast cost of gas are of key concern. The Owen Inquiry has appointed Wood Mackenzie to investigate the ongoing availability and cost of gas supplies for base load generation in NSW.

In particular, the Owen Inquiry has requested that Wood Mackenzie assess the availability and cost of gas for the period out to 2030 under four specific scenarios. These scenarios represent the progressive substitution of the NEMMCO forecast (NEMMCO SOO 2006) coal fired generation by gas fired generation as new baseload generators over the period 2013 to 2016.

1.2 Methodology

The Eastern Australia gas and power markets have evolved from isolated state-based markets into a more integrated and dynamic semi-national energy market. As such, any evaluation of the gas supply availability and cost for NSW cannot be assessed in isolation but must be assessed as part of the integrated supply/demand system in Eastern Australia. This is especially so with NSW given its current reliance on gas supply from interstate sources, due to the very limited indigenous gas production.

To address the objectives, Wood Mackenzie has incorporate the following approach;

- Gas Demand – The generation scenarios being evaluated represent changes in gas demand in NSW. Wood Mackenzie utilised our generation modelling on Eastern Australia to determine the total gas demand for generation for NSW over the forecast period (out to 2030). This generation demand was added to our state-by-state and sector-by-sector gas demand model to provide an assessment of the outlook for total Eastern Australia gas demand.
- Gas Supply – Wood Mackenzie provides an overview of Eastern Australia's gas reserves and gas production. In addition, given the growing importance of Coal Seam Gas (CSG) in Eastern Australia gas supply, we have provided an outlook for potential additional supply from CSG. The implication of the resulting gas demand and supply outlook in Eastern Australia is discussed.
- Gas Transmission System – Wood Mackenzie provides a review of the key pipelines delivering gas into NSW, current or future limitations of gas transmission, expansion capability and new pipeline infrastructure planned or required. The likely timing requirements for expansions or new pipelines together with estimates of the lead time for such augmentation are provided.
- Gas Supply Contracting for NSW Generation – Wood Mackenzie provides a review of recent contract terms for gas supply to gas-fired generation (annual and total volumes, supply source, term of contract and special conditions with respect to the supply source). We also outline key aspects affecting the future willingness of producers to supply together with lead times for contracting and developing supply.
- Delivered Gas Price Outlook – In assessing the implications for gas price, Wood Mackenzie assessed the key gas pricing driver, the relative cost of gas-fired and coal fired generation and the cost of long-distance gas supplies.
- Supply Security – Wood Mackenzie reviewed the development of the Eastern States gas market, key aspects of supply security (storage, pipeline flexibility, supply sources and delivery options). We reviewed some of the historical supply interruptions and consequences/timing of outage and the implications for future supply security.

2. Gas Demand

Historically, the Eastern Australia gas markets were characterised by discrete demand regions connected to single supply sources by a single transmission pipeline. As such, these markets operated semi-independently. However, today's market is much more interconnected, through additional gas delivery infrastructure as well as gas-fired generation into the NEM (National Electricity Market). Therefore, the availability of gas supply to meet the requirements of potential future gas-fired baseload generation in NSW, must be assessed in the context of the total Eastern Australia gas demand and supply picture.

In order to understand the gas demand requirements, Wood Mackenzie has modelled the generation capacity scenarios provided by the Owen Inquiry Secretariat. Wood Mackenzie's power generation analysis utilises the same methodology which we used in our "*Eastern Australia Gas & Power Outlook to 2025 – Fitting the pieces togethe*r" syndicated study. This methodology is summarised as follows:

- Establish the Macro drivers for electricity demand, by state
- Build up a Demand overview, based on macro economic drivers
- Construct the electricity Supply model, using known plant capacities, constraints and publicly announced projects
- Incorporate current and proposed generation plants, utilising new build costs as the basis of economic generation stack
- Develop outlook scenarios based on supply opportunities that meet market and legislative constraints.

It is important to note that the modelled gas demand requirements of this report are based on the generation capacity scenarios provided by the Owen Inquiry Secretariat and that these scenarios and their outcomes are different from the scenarios outlined in our "*Eastern Australia Gas & Power Outlook to 2025 – Fitting the pieces togethe*r" syndicated study.

2.1 NSW Gas Demand Assumptions

As requested under our consultancy for the Owen Inquiry, the following analysis looks at the implications for demand as a result of the specified scenarios of gas-fired generation for NSW. The Owen Inquiry wished to assess the availability and cost of gas supply to potential baseload gas fired generation power stations (Combined Cycle Gas Turbine – CCGT) under a number of scenarios. In assessing the cost of gas, the Owen Inquiry Secretariat sought forecasts for the period out to 2030 to supply gas-fired generation at both 50% and 75% capacity.

The scenarios included:

1. Business as usual
2. 1,000MW of gas-fired baseload power generation in NSW;
3. 2,000MW of gas-fired baseload power generation in NSW; and
4. 2,500MW of gas-fired baseload power generation in the NEM.

The scenarios are based on the NEMMCO 2006 SOO with additional new gas fired generation progressively substituting for the new coal generation set out in the NEMMCO 2006 SOO table H8.

Scenario 1 – "Business as usual" represents a low gas demand case as all the baseload capacity installed for the period 2013 to 2016 in NSW and Victoria under this scenario are coal fired generators (consistent with the NEMMCO 2006 SOO table H8). We have referred to this resulting gas demand as our Base Gas Case Demand. The Base Gas Case Demand includes the existing gas-fired generation in NSW (including co-generation facilities and Coal Mine gas generators) plus committed gas-fired generation – Tallawarra CCGT (under construction).

Wood Mackenzie has also included the following publicly announced gas-fired generation projects in our modelling (Note: these are not firm commitments and ultimate development is not certain);

- Marulan and Bamarang CCGT – Proposed (sequenced based on Wood Mackenzie modelled timing)
- OCGT 2010 to 2012 – Advanced Proposals {Eraring (40MW), Munmorah (660MW), Uranquinty (640MW)}
- OCGT 2010 to 2012 – Proposed {Bega (120MW), Cobar (114MW), Tomago (500MW)}

OCGT (Open Cycle Gas Turbine) power stations are designed to provide peak period generation and their resulting generating hours in a year are generally low. They therefore have a limited impact on the overall gas demand volume requirements. However, their gas capacity requirements can be very significant but this has not been assessed as it is beyond the scope of this study.

NSW Generation Capacity Expansion (MW) Scenarios

			2010	2011	2012	2013	2014	2015	2016
Base Gas Case Demand	NSW	Coal				500	500	500	500
		CCGT	420 (Tallawarra)	300 (eg: Marulan)	400 (eg: Bamarang)				
	Vic	Coal					500		
		CCGT							
High Gas Case Demand	NSW	Coal							
		CCGT	420 (Tallawarra)	300 (eg: Marulan)	400 (eg: Bamarang)	500	500	500	500
	Vic	Coal							
		CCGT					500		

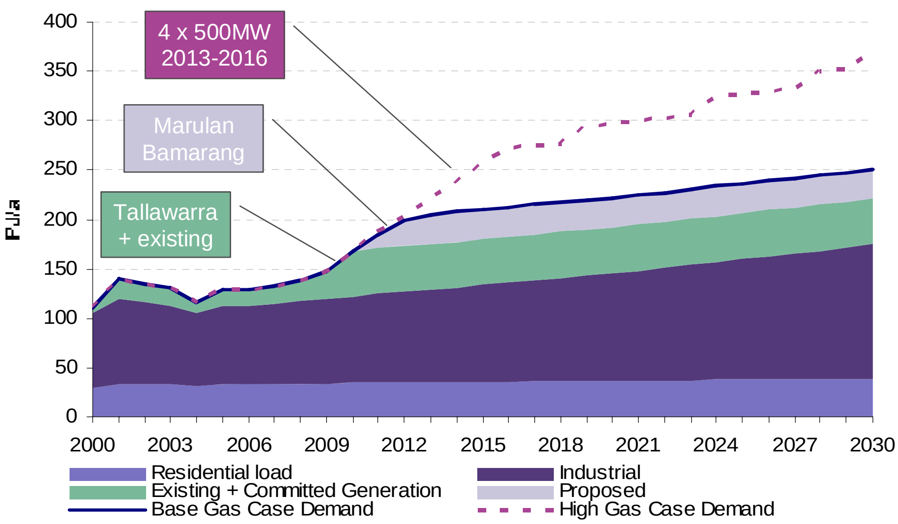
Note: The timing of the capacities in the table above represent the first full year of operation of the installed generation capacity for modelling purposes only.

The annual gas demand for the 300 to 420MW Tallawarra, Marulan, and Bamarang CCGT's at 75% load factor is approximately 10 to 13PJ/annum. For the 500MW CCGT's, the gas demand at 75% load factor is approximately 15PJ/annum.

Scenario 4 – 2,500MW of gas-fired baseload power generation in the NEM represents the High Gas Case Demand as all the capacity installed for the period 2013 to 2016 in NSW and Victoria under this scenario are gas fired generators.

The total NSW gas demand forecast is represented in the following graph.

NSW Gas Demand 2000-2030



Source : Wood Mackenzie

Scenarios 2 and 3 represent gas demand within the range of the Base and High Gas Case Demands for NSW.

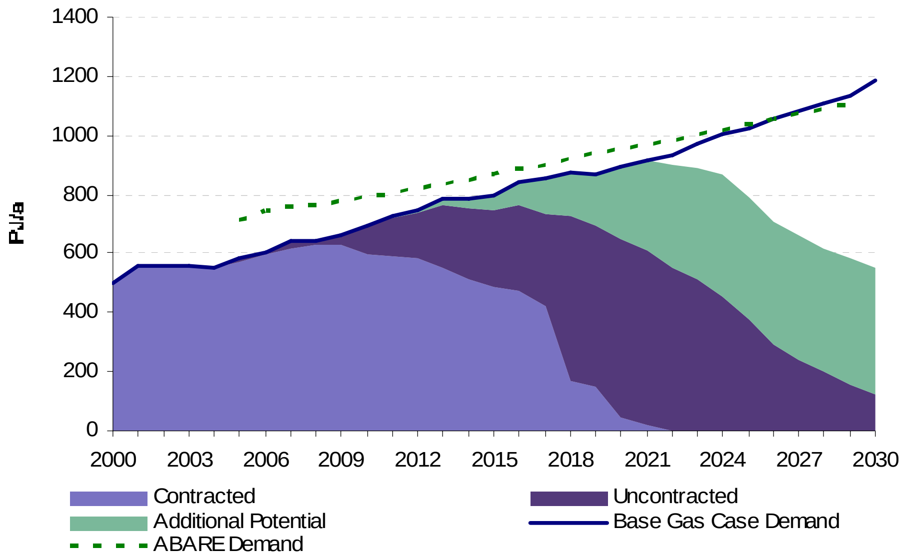
The NSW gas demand cases were added to the remaining gas demand for Eastern Australia. Supply was then modelled to best meet the forecast demand.

Illustrated below is the aggregate Eastern Australia gas demand under the Base Gas Case Demand for NSW. For comparison, we have included ABARE's (Australian Energy National and State Projections to 2029-30) gas demand. The difference in initial gas demand in 2006 between Wood Mackenzie and ABARE are a result of different gas demand methodologies:

- Wood Mackenzie's gas demand represents the sales gas at the point of injection of each supply point (ie. Ex-plant, after fuel and production losses).
- ABARE's gas demand represents the total gas production (ie well head production, before fuel and production losses) and including ethane.

The demand lines under the two approaches converge by the end of the forecast period. Taking into account the different methodologies to gas demand, the Wood Mackenzie's Base Gas Case Demand for Eastern Australia therefore represents an overall higher growth forecast than ABARE.

Eastern Australia Base Gas Case Supply/Demand 2000-2030



Source : Wood Mackenzie

The supply matching is addressed in the following section.

3. Gas Supply

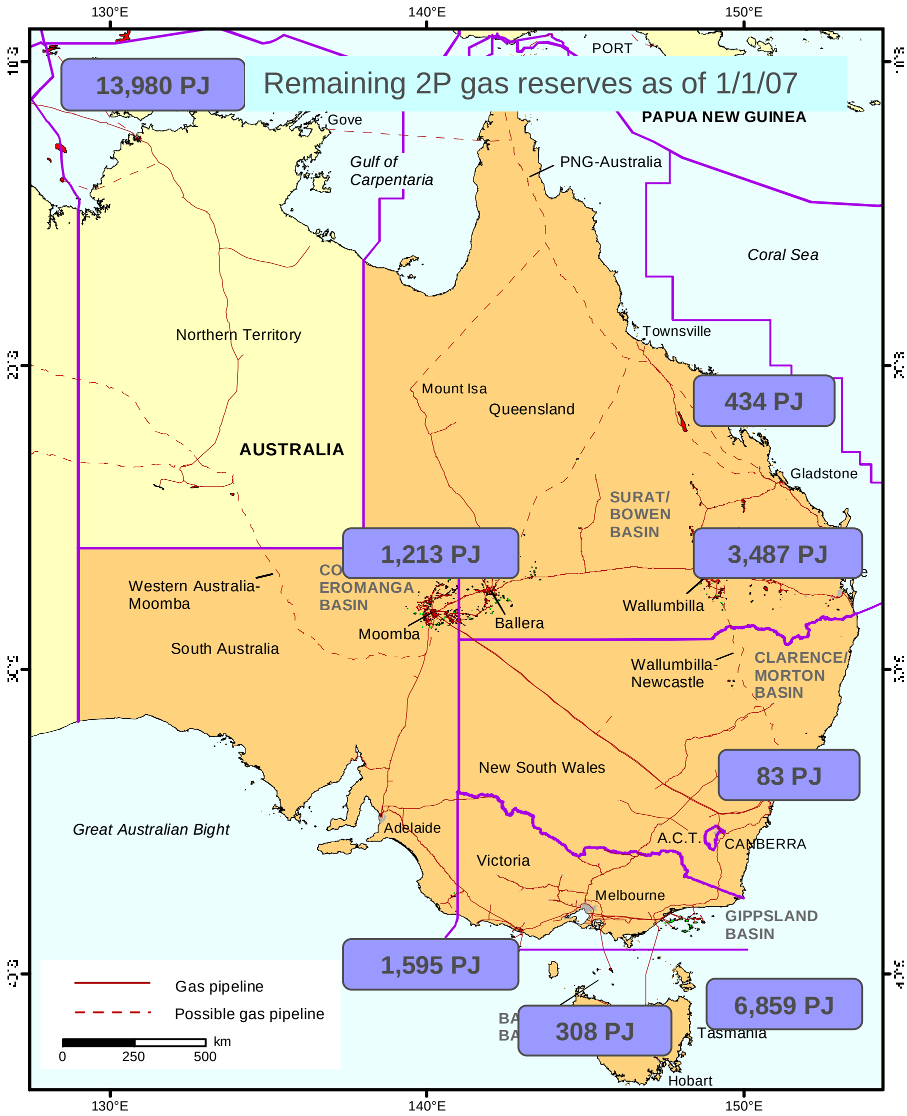
The analysis in this section is based upon Wood Mackenzie's extensive research databases together with the our recently completed "*Eastern Australia Gas & Power Outlook to 2025 – Fitting the pieces together*" syndicated study.

3.1 Gas Reserves

3.1.1 Proven and Probable (2P) Reserves

Proven and Probable gas reserves or 2P gas reserves, represent the industry's expected volume of gas that can be produced and sold. It is general industry practice in Australia to contract based on 2P gas reserves volumes. Therefore the level of 2P reserves is a key indicator of the future potential of gas supply.

Eastern Australia 2P Gas Reserves (1/1/07)



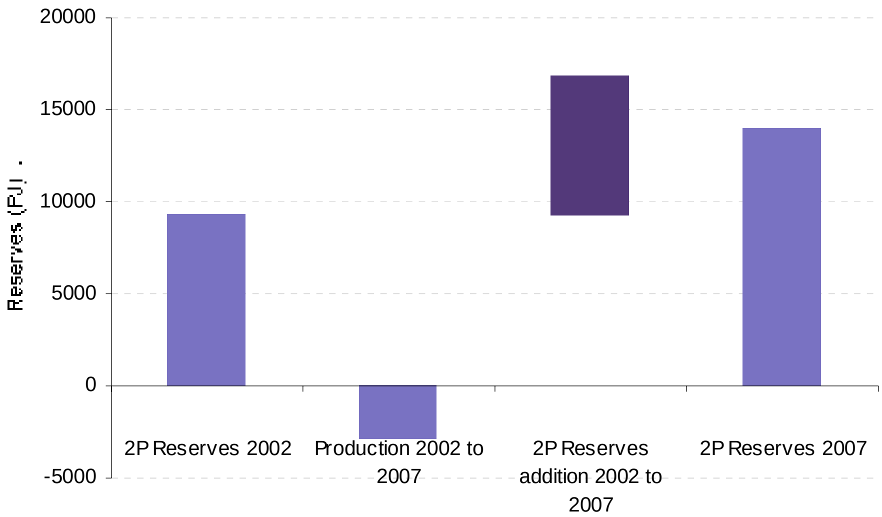
Source : Wood Mackenzie

The total 2P gas resource of Eastern Australia as of 1/1/07 is 13,980 PJ. This equates to approximately 23 years of production at current levels. The Gippsland Basin, with 6,859 PJ of reserves remains the most significant region in Eastern Australia in terms of gas reserves (and production) despite over 30 years of gas production. By contrast, the Cooper Basin has 1,213 PJ of 2P gas reserves and production is now in decline following 30 years of production.

CSG 2P reserves are approximately 4,000 PJ. The main area of CSG reserves is located in SE Queensland.

A comparison between the gas reserves (2P) in Eastern Australia over the last five year period (2002 to 2007) shows that despite approximately 2,800 PJ of sales gas being produced in this period, 2P gas reserves have actually increased by a net 4,710 PJ. This demonstrates a healthy reserves replacement ratio of 260% over this five year period.

Eastern Australia 2P Gas Reserves Comparison 2002 vs 2007



Source : Wood Mackenzie

The key areas that have contributed to this increase in 2P gas reserves are the Gippsland Basin and Coal Seam Gas (CSG) in Queensland. In the Gippsland Basin, significant reserves have been added through reserves upgrades from existing producing gas fields as well as appraisal of sub-economic discoveries (eg Longtom and Basker/Manter/Gummy). CSG reserves have increased from a small volume in 2002 to ~4,000PJ in 2007. This has occurred predominantly in Queensland where production has also increased significantly. CSG projects have established their economic viability through pilot projects and have begun to transform their gas resource (“Possible” component of 3P reserves) into contracted 2P reserves and production.

3.1.2 “Additional Potential” Reserves

A third category of gas reserves is 3P or Proven plus Probable plus Possible reserves. Generally, this reserves volume is only considered in assessing upside potential as it has greater uncertainty with a probability of only 10%. However, in CSG projects, the use of the 3P reserve figure reflects a different methodology used to calculate this resource compared to conventional gas fields – i.e. the believed extent of the gas-bearing coals, rather than the probabilistic approach used in conventional gas fields.

Strictly defining CSG 3P reserves as only having a 10% probability in areas surrounding existing production may be pessimistic. The areal extent and quality of the gas-bearing coals may be well understood but the reserves may only be classified as “Possible” because of the lack of closer spaced drilling. The process of conversion of the “Possible” component of 3P CSG resource to “Probable” may only require a more closely spaced drilling.

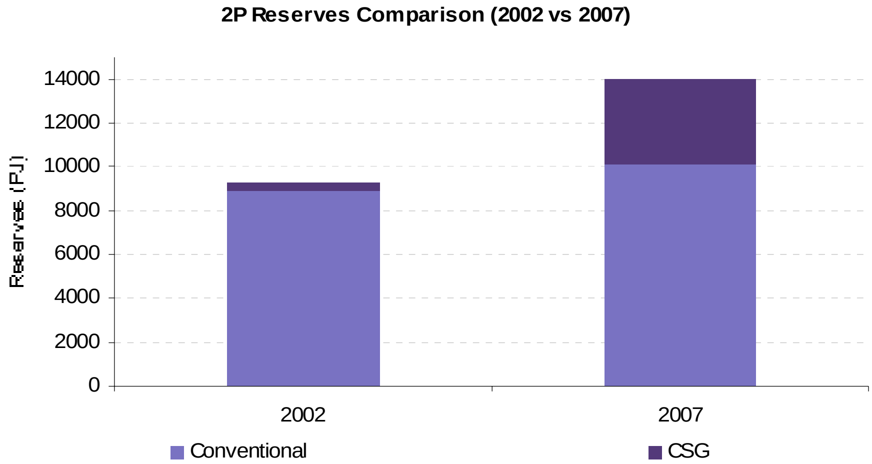
During the early stages of CSG development, the initial focus of activities is establishing the economic basis for future production. This involves pilot projects which test the production capabilities of the coal seams. The completion techniques of the wells may also be tested to optimise the production rates relative to the well costs. Additional drilling may also be undertaken to begin to establish a 2P reserves base to enable sales contracts to be executed once economic production has been established. Whilst the 3P resource may be high in this initial period, the 2P resource is generally low. Only though further drilling can the 2P reserves be increased.

With relative low production rates early on in a CSG projects development, drilling to establish 2P reserves can typically have a negative effect on cash flow. The conversion to 2P reserves therefore needs to be balanced against the expected rate of production growth (and commercialisation of the reserves through supporting contracts), particularly with smaller companies with limited financial resources.

As CSG projects begin commercial production, they can incrementally add capacity (pipelines, processing plant and compression) to increase production. The ultimate plateau rate for a project will depend on the available market, the costs of development, the production profile and ultimate recovery per well. As a result, CSG projects tend to expand capacity incrementally and 2P reserves growth increases over time until an economic plateau in production is reached and maintained.

This can be seen from a comparison of the Eastern Australia CSG reserves over time. In 2002, CSG 2P reserves were less than 500PJ but by 2007, CSG 2P reserves are ~4000PJ.

Eastern Australia CSG Reserves 2002 vs 2007



Source : Wood Mackenzie

In order to capture an estimate of the likely evolving reserves and production growth of CSG in Eastern Australia, Wood Mackenzie's has assessed a proportion of the "Possible" 3P CSG resource on the basis that it can be economically converted to 2P reserves and production within the timeframe of this study outlook. We have called this "Additional Potential". This class of potential future supply utilises our estimate of supply, over and above current Contracted and Uncontracted reserves (Proven plus Probable - 2P). The "Additional Potential" resource and production forecast represents Wood Mackenzie's estimated view of the medium term potential of the overall CSG gas resource. Further reserves additions and production above our forecast are possible.

The criteria Wood Mackenzie used for the Additional Potential resources was as follows:

- The ultimate "Additional Potential" reserves quantity used for a given project was limited to less than 80% of the "Possible" reserves for the project.

- A modelled production plateau of at least ten years was required to support the level of capacity expansion. This took into account the different production profiles of wells between projects. The number and timing of wells required (both production and work-overs) together with supporting infrastructure (pipelines, plant and compression) was analysed to determine the forecast production level.

- The production expansion of each CSG project was required to be economically viable at current gas prices.

The Additional Potential gas resource represents a significant volume (8,578PJ) of potential gas for future development and production. Note, this does not represent the ultimate 3P CSG resource potential of Eastern Australia, rather it is Wood Mackenzie's view of the current 3P resource that we believe is capable of being economically developed in the period to 2030. Within the parameters set out above, we have forecast that 55% (4,935PJ) of this Additional Potential gas resource can be developed and produced in the period out to 2030.

The addition of further 3P reserves are likely over the forecast period as exploration continues and new projects are assessed.

Eastern Australia 2P and Additional Potential Gas Reserves

Source : Wood Mackenzie

In the United States of America (US), CSG is a significant contributor to the gas production in that country. CSG production in the US will be approximately 2,000 PJ in 2007 (or over three times the total Eastern Australia annual gas demand).

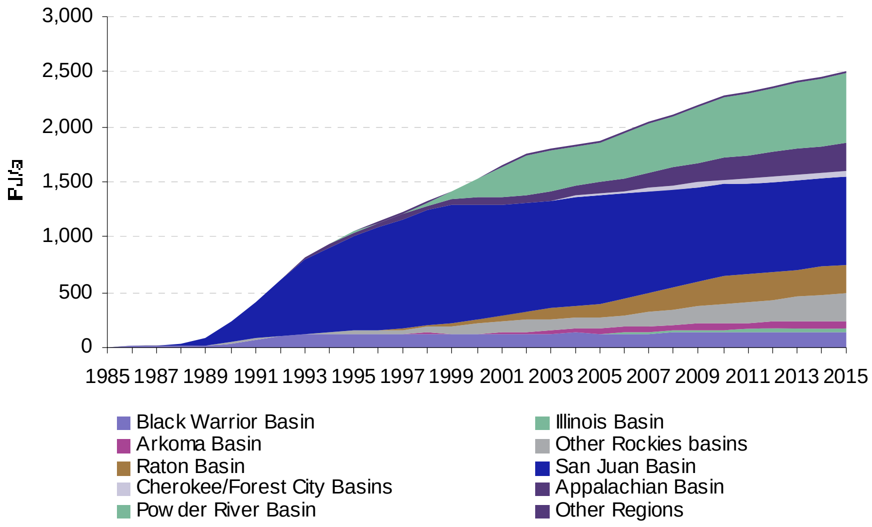
The US CSG industry has been assisted by a number of factors including:

- Tax credits (until 1992)

- Readily available market for produced gas; and

- High gas price (post-2000)

US CSG Production by Basin 1985 to 2015



Source : Wood Mackenzie

Whilst Eastern Australia CSG development has not benefited from these factors available to the US CSG industry, there are some key characteristics of the nature of US CSG production that can be drawn on as an example of the potential for the developing Australian CSG industry. These are;

- Start-up timing – it generally takes ~2 to 5 years to establish commercial production.
- Production Ramp-up – once production has started, production capacity is expanded as more wells are drilled and bought on-line. This ramp-up period can be in the order of 5 to 10 years.
- Production Plateau – There is a natural plateau level which is established based on a number of technical factors including type of coals and resulting production and recovery rates per well. Production plateaus of 10+years are a common characteristic of CSG development.

The Australian CSG industry is very much in the early stages of development with many projects in the Start-up phase and only a handful in the Production Ramp-up phase. As a result, there is potentially an enormous production upside as the industry expands to a plateau level.

3.1.3 Yet-to-Find Gas Resource

It is highly likely that further discoveries of gas will be made in Eastern Australia in the period to 2030, however quantifying this potential is very difficult and Wood Mackenzie has therefore not included any estimate of Yet-to-Find resource in our analysis. In the period out to 2030, additional exploration for conventional gas reserves will be undertaken both onshore and offshore. In particular, further exploration is expected in the offshore Otway, Bass and Gippsland basins and each of these basins has illustrated successful discoveries of gas reserves in recent years.

Conventional gas has the potential to have associated liquid hydrocarbons (oil and/or condensate) which can add significantly to the value of a gas resource. Together with the size and relative proximity to existing infrastructure, these factors could enhance the economic attractiveness in developing a new gas discovery over CSG developments (which contain no associated liquid hydrocarbons).

3.1.4 Alternative Gas Supply Options for Eastern Australia

Other alternative gas supply options may develop or have the potential to be develop as alternative supply sources to Eastern Australia in the period out to 2030. These include:

- **Tight gas** – tight gas resources exist in the onshore Cooper and Gippsland basins. These are known resources but with the higher development costs associated with extracting this resource, they are currently sub-economic. With higher gas prices, this tight gas resource could be developed and contribute to the gas supply in Eastern Australia. It is possible that this resource could begin to be developed within the next 15 years, subject to higher gas prices than present.

- **Long-distance pipeline gas** – Large volumes of undeveloped gas resources exists off the North West coast of Western Australia. A future pipeline linking these resources to Moomba (acting as a hub for Eastern Australia) has been considered in the past. Recent rises in the price of domestic gas in Western Australia have seen the gas price rise to over $5.00/GJ. At these prices, together with an indicative transportation cost from Western Australia (in the order of $1.50-2.00/GJ), the delivered price for Western Australia gas to Sydney would be in the order of $8.00/GJ. It is unlikely that there will be sufficient un-met demand to support the large capital investment of a trans-continental pipeline any earlier than 2020.

- **LNG Importation** – As an alternative to long-distance pipeline gas, LNG could be imported directly into NSW. This would require development of re-gasification infrastructure (jetty, re-gas plant and storage facilities). At current prices, the equivalent delivered cost of gas to NSW by LNG would be in the order of A$10 to $13/GJ. As with long distance pipeline gas, it is unlikely that the Eastern Australia gas market would require this type of supply before 2020.

3.2 Demand Supply Outlook

3.2.1 Methodology

Wood Mackenzie has built a gas supply forecast based on a project by project analysis of 2P (Proven plus Probable) gas reserves and supply capacity. In addition, we have evaluated a portion of the 3P (Possible) gas reserves of specific CSG projects that we believe is capable of development and production within the period to 2030. For this report, Wood Mackenzie has provided this analysis on a total supply basis for Eastern Australia, with future production divided into three categories, each with a different degree of certainty that the gas will be delivered to market. The three categories are: existing Contracted production, the Uncontracted remaining reserves, and the likely Additional Potential gas. The precise definition of each of these categories is outlined below.

3.2.2 Contracted production

The gas market in Eastern Australia has been characterised by long term gas sales agreements (GSAs) between gas sellers and buyers. We have modelled contracted volumes based on current 2P (Proven plus Probable) gas reserves.

For each gas field and CSG project, we have prepared production forecasts for known sales agreements. In most cases, the proven plus probable (2P) reserves of an individual field or project are sufficient to fulfil the GSA. However, there are several projects where the 2P reserves are insufficient to meet the contracted volumes. In these cases, we have only modelled the proven plus probable reserves. This methodology applies to both conventional gas fields and CSG projects. This contracted production provides the greatest certainty of delivery to market.

Gas that is sold within the portfolios of the energy retailers (eg. Origin Energy), is also included within the contracted production category.

3.2.3 Uncontracted production

Uncontracted production is the 2P reserves that are not assigned to a GSA, but which are likely to be produced following the fulfilment of the existing agreements.

There is a higher uncertainty as to whether this gas will be delivered to market according to our forecast. This uncertainty is primarily a market risk, rather than project risk.

3.2.4 Additional Potential production

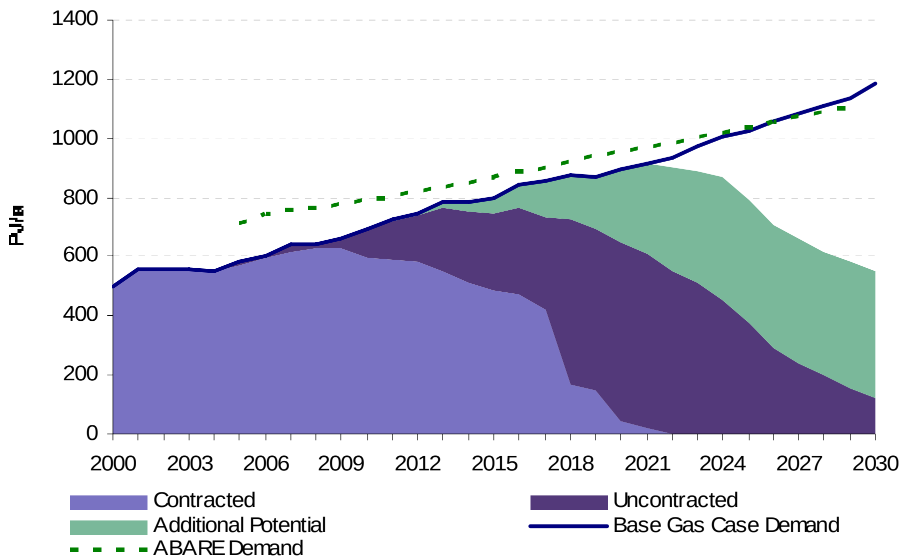
As described in the previous section, this category relates to Wood Mackenzie's analysis of how "Possible" reserves of CSG projects may be developed in the medium term. This has the highest degree of uncertainty of the production classifications but represent Wood Mackenzie's view of the expected continued growth of the CSG industry in Eastern Australia.

3.2.5 Base Gas Case Supply/Demand

In the Base Gas Case Supply/Demand outlook, the gas volumes produced in the period 2007 to 2030 are as follows;

- Contracted 6,467PJ
- Uncontracted 6,972PJ
- Additional Potential 4,857PJ

Eastern Australia Base Gas Case Supply/Demand 2000-2030



Source : Wood Mackenzie

A supply shortfall against current 2P reserves (Contracted and Uncontracted) is forecast to develop around 2013. However when taking into account the Additional Potential, the supply gap begins from 2021, with a volume shortfall to 2030 of 2,934PJ. Whilst onshore gas discoveries can be developed within a couple of years, a stand-alone offshore gas development can take in the order of 5 years to develop. However, there is a 13 year period for exploration and development to undertaken in order to try and fill this supply gap. This period provides a reasonable time period for potential yet-to-find resource and/or further development of the CSG resources in Eastern Australia to be undertaken. With a reserves replacement ratio over the last five years at a very healthy 260% and likelihood for continued reserves additions in the medium term, it can reasonably be expected that this supply gap can be met.

3.2.6 High Gas Case Supply/Demand

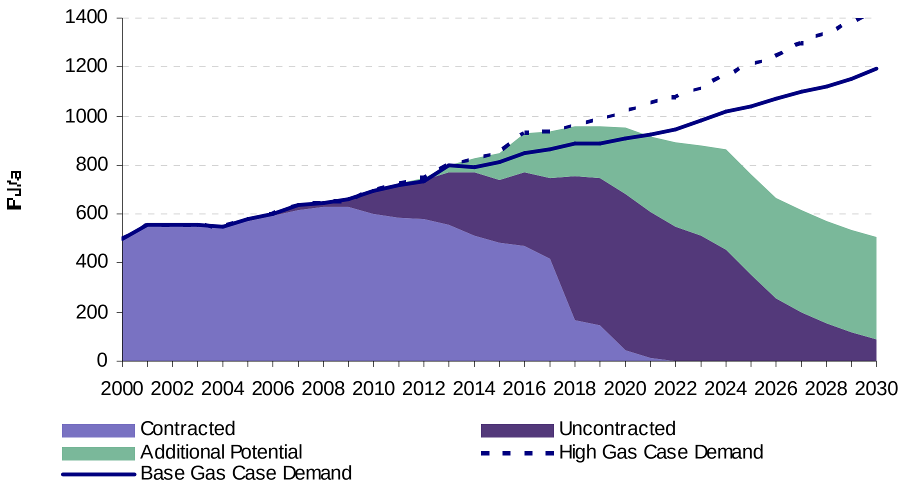
In the High Gas Case Supply/Demand outlook, the gas volumes produced in the period 2007 to 2030 are as follows;

- Contracted 6,467PJ
- Uncontracted 6,914PJ
- Additional Potential 5,172PJ

In the High Gas Case Supply/Demand, the supply shortfall begins from 2018 (based on the Additional Potential forecast) and the volume shortfall to 2030 is 5,194PJ. This case creates a higher level of uncertainty than the Base Gas Demand Case for supply availability in the future. However, this higher demand is expected to drive gas prices higher over the forecast period and this should help encourage the search for future gas reserves. In addition, the higher gas prices may begin to make “tight gas” resources economically viable for development.

If insufficient gas reserves are discovered in the period to 2020, gas demand growth post 2020 is likely to be much lower than our forecast. A significant proportion of gas demand growth in the period out to 2030 is forecast to be driven by gas demand for generation. If gas availability and/or higher gas prices start to become an issue, new gas-fired generation capacity forecast to be installed in the period post-2020, is likely to switch to alternative technology, thereby reducing the gas demand growth rate post-2020.

Eastern Australia High Gas Case Supply/Demand 2000-2030



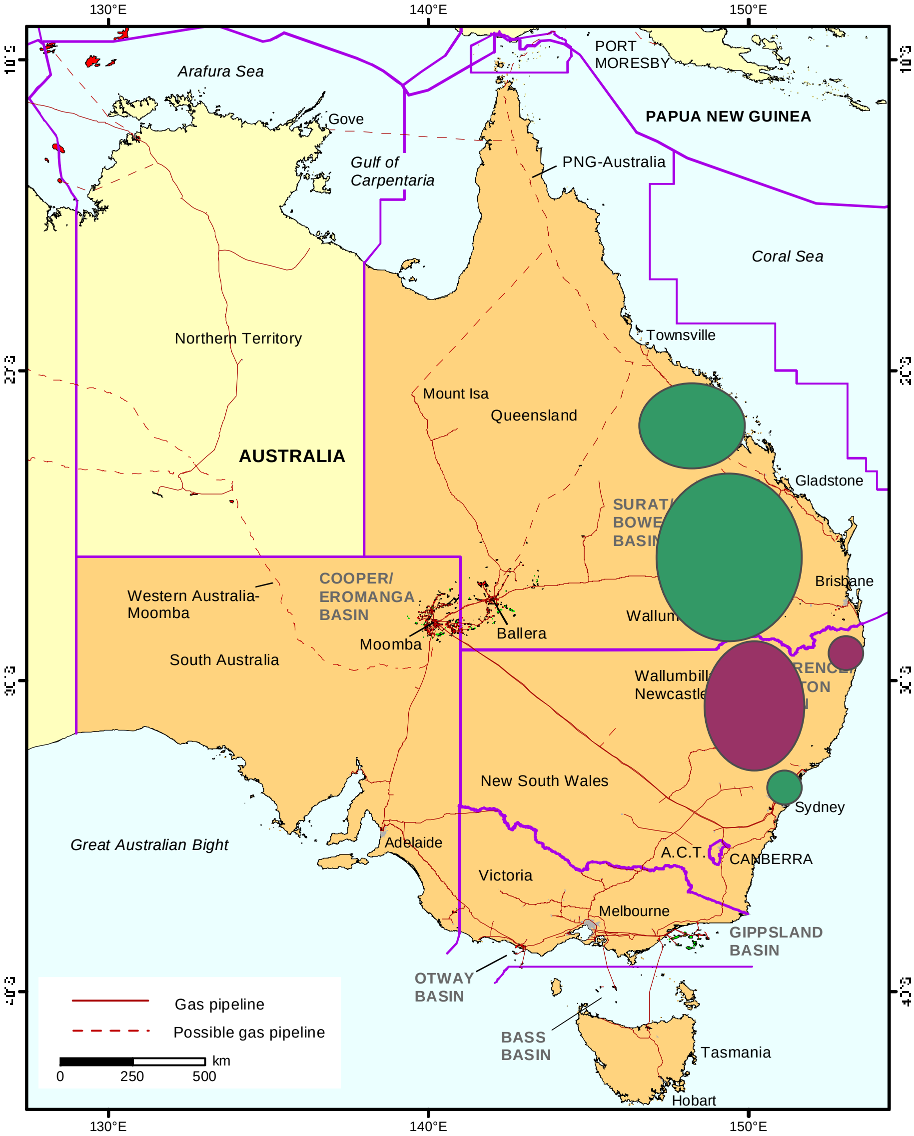
Source : Wood Mackenzie

3.2.7 CSG Gas Potential

CSG production to date has been located in two main areas NE Queensland (Moranbah project) and SE Queensland (multiple projects). NSW has had some small CSG production from the Camden gas project.

Additional areas in NSW are under evaluation including the Gunnedah-Surat, Clarence Morton, Sydney and Gloucester basins.

Eastern Australia CSG Potential

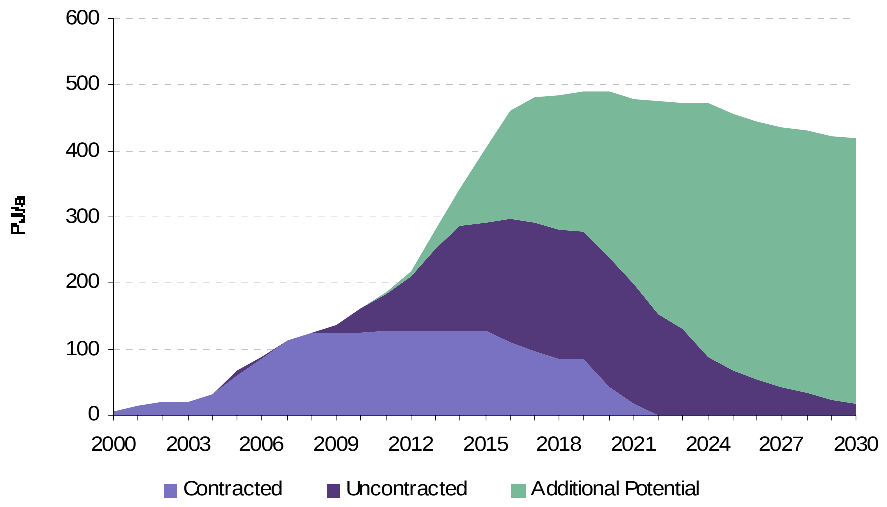


Source : Wood Mackenzie

CSG production has grown significantly from ~5PJ/a in 2000 to >100PJ/a in 2007. In the same time period, CSG 2P reserves have grown from ~200PJ to 4,000PJ. There are currently sufficient Contracted and Uncontracted 2P CSG gas reserves to underpin a significant increase in production in the period from 2009 to 2015 (up to 300PJ/annum). Further growth of 2P reserves is likely but the rate at which reserves will be added will depend on the level of gas demand growth. There is limited incentive for CSG producers to build gas reserves if they are to remain in the ground un-produced for long periods of time.

The process of converting CSG 3P resource into 2P and into production is a continually evolving process. With the CSG industry in Eastern Australia in only the early stages of development there is significant potential for continued growth in both reserves and production. Queensland in particular has demonstrated the world-class quality of some of the existing CSG developments (Fairview, Spring Gully and Undulla Nose area).

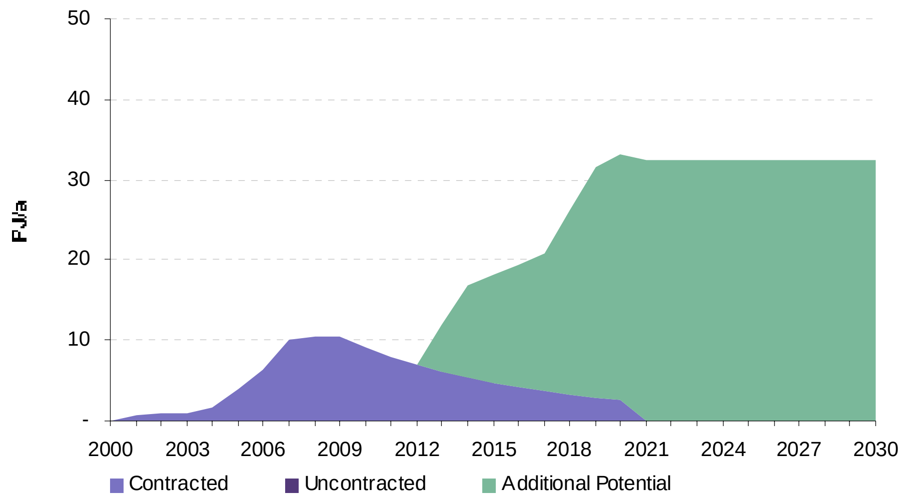
Eastern Australia CSG Production Forecast 2002 vs 2030



Source : Wood Mackenzie

The potential for NSW CSG is enormous given the extent of gas bearing coals in the Gunnedah-Surat, Clarence-Morton and Sydney basins. However, these basins are only in the early stages of evaluation and yet to prove significant commercial production. As illustrated below, Wood Mackenzie's NSW CSG outlook is relative modest with ~30PJ/a forecast for NSW by 2019.

NSW CSG Potential



Source : Wood Mackenzie

There are a number of projects in the early stages of production assessment in NSW. These include the Camden, Bohena, South Casino and Gloucester projects. Exploration around these projects is also continuing.

Santos recently announced their farm-in to CSG exploration acreage in the Gunnedah Basin. Santos bring considerable CSG expertise based on their Queensland CSG operations, together with their significant financial resources to fund exploration and possible future development in this region.

Future potential gas developments in NSW will have the benefit of the proximity to demand centre over interstate gas supplies. Therefore any future development will have a positive impact on both the delivered gas cost and supply availability for NSW.

3.2.8 Implications of Proposed LNG Export from Eastern Australia

Santos and Arrow Energy have recently announced proposals for LNG projects in Gladstone. A summary of the proposed projects is provided in Appendix I. It is important to note that these projects are in the early stages of assessment. Detailed studies are required to understand the viability of these proposed LNG projects. Both projects require the certification of sufficient gas reserves to underpin long-term LNG supply contracts. Whilst Wood Mackenzie has not assessed the specific economics of these projects, both companies have sufficient encouragement from initial scoping economics to proceed into the next phase of evaluation. However it should be noted, the large capital investment of LNG projects makes them particularly challenging under the current cost environment (labour and material).

Implications for gas availability in Eastern Australia – The announcements of the proposed developments for Eastern Australia LNG exports represent a significant vote of confidence by the proponents in the potential of the CSG resource. Of particular interest is;

- The gas reserves required to underpin these developments is significant. For the Santos proposal, between 4,000 and 5,500PJ will be required. For the Arrow Energy proposal at least 1,000PJ will be required, although with the option to expand, the volume could be in the order of 2,000PJ to 3,000PJ.
- The gas certification process will run in parallel with detailed studies. As a result the exploration and appraisal work will be undertaken over the next two years.
- The development of CSG processing capacity is significant, approximately three times the current level of CSG production.

There is a risk that any development of an LNG export project could reduce the availability of gas to the domestic gas market in Eastern Australia. This could occur through the preferential allocation of uncontracted reserves to support the possible long-term LNG contracts entered into as part of any LNG development. However, it should also be recognised the significant investment (exploration and appraisal work) in reserves certification required from both Arrow Energy and Santos over next two years. Both companies have confidence in the potential of their CSG resources. In addition to these CSG producers, there are other CSG explorers and producers that will also be undertaking exploration and appraisal at this time. The significant increase in activity associated with this reserves and production expansion could be impacted by the availability of material, equipment and labour. A shortfall in gas availability in Eastern Australia is therefore more likely to be a result of constraints on the speed to develop the resource into production rather than limitations on the overall resource base available.

4. Gas Infrastructure

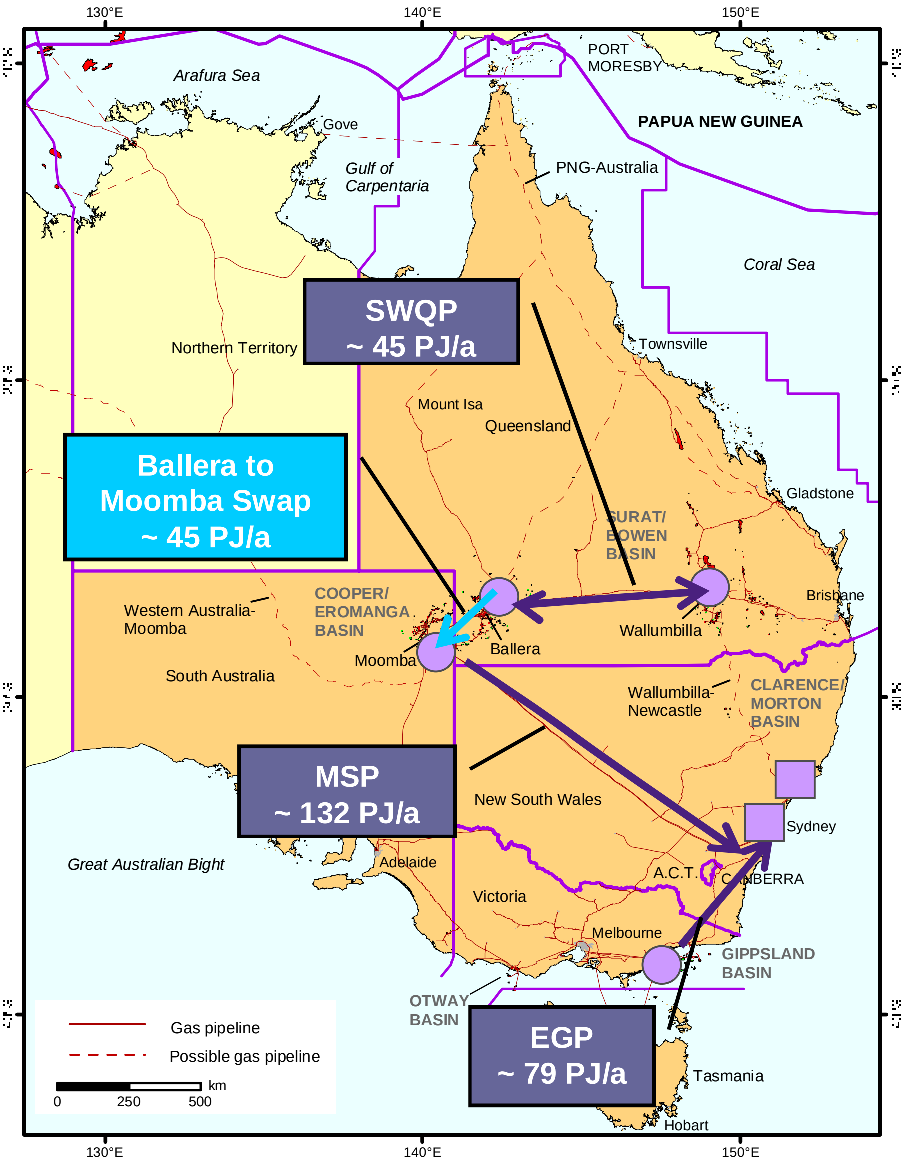
4.1 Existing Gas Infrastructure

The New South Wales current gas demand of 132 PJ *per annum* is supplied by two key transmission pipelines;

- Moomba to Sydney Pipeline (MSP); and
- Eastern Gas Pipeline (EGP)

(The Victoria / New South Wales Interconnect gas pipeline is a distribution pipeline linking between the two states with only a small volume throughput).

Current Pipeline Capacity (Assuming 85% Load Factor)



Source: Wood Mackenzie

In assessing the gas infrastructure requirements for NSW, Wood Mackenzie has focussed our analysis on pipeline annual throughput rather than total delivery capacity of the transmission pipelines. We have therefore made an adjustment to the nominal maximum capacities of the pipelines to recognise the need of these pipelines to meet the overall market demand in NSW. This adjustment limits the maximum annual throughput for the pipelines based on a maximum load factor (LF) of 85% of the pipeline capacity over a year.

The Moomba to Sydney pipeline allows gas to flow from the Cooper Basin to New South Wales. The 1,300 kilometre pipeline to Wilton, some 50 kilometres southwest of Sydney, is owned and operated by Australian Pipeline Trust (APT). Laterals from this pipeline distribute gas to other markets in New South Wales (e.g. Newcastle, Wollongong, Bathurst and Wagga Wagga) and the Australian Capital Territory (Canberra). The pipeline currently has a maximum capacity of 155 PJ *per annum* (throughput of 132PJ/a at 85% LF) but could be increased significantly with further compression if required.

Existing and New Pipeline Details

Pipeline	Owner	Distance (KM)	Timing	Capacity (PJ/a)	Throughput @ 85% LF (PJ/a)
Existing/Comitted					
South West Queensland Pipleline	EPIC Energy	756	Existing	53	45
Moomba to Sydney Pipeline	APT	1300	Existing	155	132
Eastern Gas Pipeline	Alinta	795	Existing	93	79
New/Expansion					
Hunter Valley Pipeline (New)	Hardie Holding	850	2013	60	51
Bulla Park (New)	APT	763	2014	60	51
Eastern Gas Pipeline (Compression)	Alinta	795	2013	132	112
QNS Link (New)	EPIC + APA	180	2009	73	69
South West Queensland Pipleline (Compression)	EPIC Energy	756	2009	108	92

Source: Wood Mackenzie

In the Cooper Basin, the Ballera Processing Centre in Queensland is connected to the Moomba Gas Plant in South Australia by a 180 kilometre, dual phase line, which transports oil and gas from Queensland to South Australia. The capacity of this gas pipeline is around 50 PJ *per annum*. This pipeline is the only physical link between the gas suppliers in Queensland and the southern gas markets.

Historically, the majority of gas delivered to markets in Queensland was from Ballera. To meet contracts with gas buyers in southeast Queensland, gas is transported *via* a 756 kilometre pipeline (the South West Queensland Pipeline – SWQP), which links the Ballera Gas Centre to the ML1A station near Wallumbilla (ie flowing west to east). However in recent years, this pipeline has begun to deliver gas to the west (reverse flow) and from later this year is expected to do so permanently. This is a result of the declining Cooper Basin production, the growing production of CSG in Southeast Queensland and the continued requirement to supply gas to markets in NSW and South Australia. The SWQP is believed to have a maximum capacity of 53 PJ *per annum* (when configured to flow westward).

In August 2000, Duke Energy commissioned the Eastern Gas Pipeline (EGP). The 795 kilometre pipeline delivers gas from the Longford Gas Plant in Victoria to the New South Wales market. The pipeline is expected to have a maximum capacity of up to 93 PJ *per annum* (throughput of 79PJ/a at 85%LF) by end-2008 with the addition of mid-line compression.

4.2 Gas Swap Arrangements

Origin Energy signed an agreement with South West Queensland Gas Producers ("the SWQ Producers") for the swapping of between 90 and 200PJ of gas between Queensland and Moomba until the end of 2011. The arrangement effectively enables Origin to deliver gas to NSW from their Queensland CSG projects. This is achieved by delivering an equivalent quantity to meet the contractual commitments of the SWQ Producers at Wallumbilla in Queensland. The SWQ Producers deliver raw gas from Ballera for processing at Moomba. There is a limit to the volumes that can be swapped in this arrangement and eventually, physical connection to the sales gas pipelines will be required (proposed QSN Link).

4.3 Potential Future Pipeline Capacity

In order to meet the forecast gas demand requirements of NSW, additional pipeline capacity will be required. This can be achieved through a combination of pipeline expansions together with new pipeline infrastructure. The investment decision for any new pipeline or expansion to the current pipeline, depends on the incremental demand for gas and the availability of future gas supply. Wood Mackenzie has taken a conservative approach to matching our gas supply outlook with the required proposed new pipelines and possible expansions.

The pipeline throughput was calculated based on a utilisation factor of 85% for all pipelines (both new and existing). The economics of the new capacity options (expansions and new infrastructure), demand requirements, required capacity, timing and supply opportunities were all taken into consideration in forming our view on the likely future pipeline developments. It is important to note that many valid alternative configurations of the gas transmission system could be developed in order to meet the future gas transportation requirements for NSW and therefore our analysis of future pipeline requirements should be treated as indicative only. Ultimately the infrastructure developments will be determined by the committed firm capacity.

The level to which indigenous gas supply within NSW can develop within the next few years will also have a bearing on the level and location of pipeline infrastructure augmentation. We have taken a conservative view on this indigenous gas in our analysis but as it has the potential for lower cost of delivery it could significantly change the supply landscape for NSW.

4.3.1 Expansions of Existing Pipelines

Existing pipeline infrastructure can be incrementally expanded through the addition of compression and looping. Initially, a pipeline will generally only have compression at the inlet of the pipe. However, as the pipeline increases throughput, the capacity of the pipeline can be increased by first adding midline compression. Depending on the length of the pipeline, additional compression can progressively added. The limiting factors on this additional compression are the operating limits under which the pipeline can run and the economic cost of the additional capacity gained (ie each additional compressor added will contribute a smaller incremental increase in capacity). After a pipeline has achieved its fully compressed capacity, the next option for additional capacity is “looping”. Looping involves the duplication of sections of the pipeline (between compression stations).

We have analysed the cost of incremental capacity to existing pipelines based on the addition of compression only. In general, compression is relatively easy and more cost effective for capacity expansion of a pipeline than looping. Addition of a compressor can be achieved within 12 months.

South West Queensland Pipeline (SWQP)

With the forecast continued decline in Cooper Basin production, both NSW and South Australia will require alternative gas supplies to meet future demand requirements. With the growth of CSG production in SE Queensland, the opportunity exists to deliver some of this gas to the southern states. In addition to the need to build the connection around Ballera to Moomba (QSN Link), the SWQP from Wallumbilla to Ballera will require additional compression in order to deliver the required quantities to Ballera and Mt Isa. With compression, this pipeline could run at a maximum capacity of 108 PJ *per annum* by 2009 in the westerly direction.

Eastern Gas Pipeline (EGP)

The EGP has recently committed to adding mid-line compression that will take its capacity up to 93 PJ *per annum* by end-2008. This pipeline can be expanded further with additional compressors up to a maximum capacity of 132 PJ *per annum* by 2014.

Moomba to Sydney Pipeline (MSP)

We have not assumed any future expansion of the MSP. This is due to limitations of supply into the MSP going forward. With the decline of Cooper Basin production, the MSP is currently running below its full capacity. Supplementing this decline in Cooper Basin production requires augmentation of the SWQP, as well as the building of the QSN Link (see below). However, even with this augmentation, the SWQP and QSN Link will not provide sufficient supply capacity to meet the maximum capacity of the MSP. To help support a higher level of throughput for the MSP in the future, APT have proposed the development of a new pipeline to bring gas from Wallumbilla to Bulla Park (WBP), mid-way along the MSP (see below).

4.3.2 Potential New Gas Infrastructure

A number of potential pipelines are currently being evaluated to deliver gas from Queensland into NSW. We have provided an assessment of the possible capacity and timing for these possible pipelines. It should be noted that the ultimate capacity and decision to proceed will be based on the level of firm commitment to the capacity on these proposed pipelines.

Queensland to South Australia/New South Wales Link (QSN Link)

On the 13th July 2007, Epic Energy announced they had entered into a long term contract with AGL to transport gas from SE Queensland for delivery into the Moomba to Adelaide Pipeline (MAPS) and the Moomba to Sydney Pipeline (MSP). In order to achieve this delivery, Epic has committed to build a pipeline connecting the SWQP to the MSP and MAPS (ie around Ballera and Moomba) – to be called the QSN Link (Queensland to South Australia/New South Wales Link). The QSN Link was formerly known as the Ballera to Moomba Interconnect. This 180 kilometre pipeline is expected to have a capacity of around 70 PJ per annum. When completed, this development will provide a seamless gas transport service from the CSG fields in SE Queensland to customers in the southern states. The pipeline is expected to commence its first delivery in January 2009.

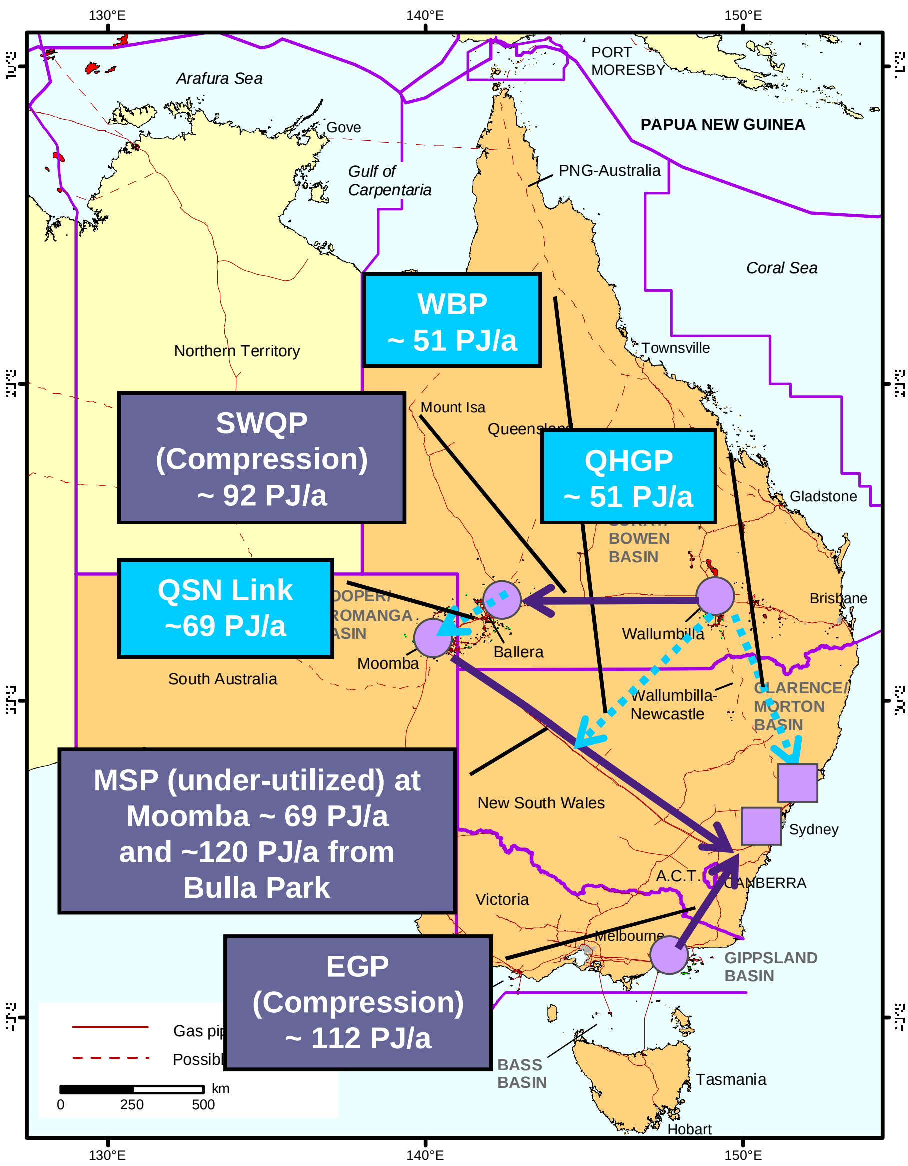
Wallumbilla to Newcastle (Queensland Hunter Valley pipeline - QHVP)

Hardie Holdings has proposed to connect the Wallumbilla Gas Hub in SE Queensland to Newcastle via the Hunter Valley. This pipeline would provide a key link in the Eastern Australian gas supply system, creating additional gas supply security to Newcastle and Sydney. Hardie Holdings is evaluating this project with its joint venture partners, Weston Aluminium, Hunter Land and ANZ Infrastructure Services. The proposed pipeline will have an approximate total length of 850 kilometres. We have assumed a capacity of 60 PJ *per annum* and development by 2013. In November 2006, the NSW Government declared this pipeline to be Critical Infrastructure under Part 3A of the Environmental Planning & Assessment Act. In February 2007, the Queensland Government granted Environmental Approval for issuance of a pipeline permit.

Wallumbilla to Bulla Park pipeline (WBP)

APT are evaluating a 753 kilometre new pipeline that would connect Wallumbilla in SE Queensland to Bulla Park on the MSP (approximately mid-way between Moomba and Sydney) in NSW. This pipeline would support continued supply into Sydney via the MSP as the Cooper Basin production declines. We have assumed a capacity of 60 PJ *per annum* and development by 2014. The rationale for this pipeline would be to utilise spare capacity in the MSP as the Cooper Basin production continues to decline and the QSN Link reaches its capacity.

Possible Pipeline Capacity by 2013-14 (Assuming 85% Load Factor)



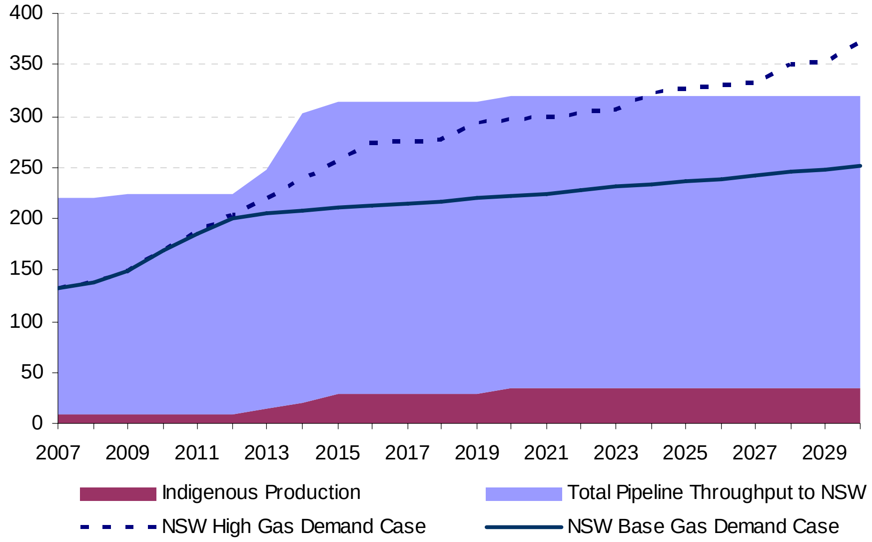
Source: Wood Mackenzie

4.4 Forecast Gas Pipeline Throughput

The following graph illustrates the forecast throughput capacity of the pipelines to meet the High Gas Case Demand requirements. This is based on Wood Mackenzie's assessment of the likely sequencing of capacity expansions and new build pipelines.

The building of the QSN Link and the reversal and compression of the SWQ Pipeline is required by 2009 to begin delivering gas supplies from Wallumbilla (the SE Queensland CSG projects) to NSW. A key driver for this investment is to help counter the forecast declining production from Cooper Basin.

Forecast Pipeline Throughput Capacity into NSW 2007 - 2030



Source: Wood Mackenzie

However, even with the QSN Link, further expansion of capacity into NSW would be required to meet growing demand. Therefore further expansion of EGP is expected to be required by 2013, up to a total throughput of 112 PJ/annum. However in the period 2013 to 2019, growing NSW demand could result in the requirement for an additional 100 PJ/annum of new transmission capacity. This demand growth would drive the need for a direct connection from Wallumbilla, south into NSW. At present two options from Wallumbilla have been proposed, to Newcastle via the Hunter region (QHGP) and to Bulla Park (WBP), mid-way on the MSP.

Both pipelines have logical reason to be built. The WBP pipeline supporting the MSP which would be under-utilised at this time and the QHGP providing gas to a developing gas region in the Hunter/Newcastle area. Both would also contribute to security of supply and system support. We have modelled both pipelines with ~50PJ/annum each starting between 2013 and 2014.

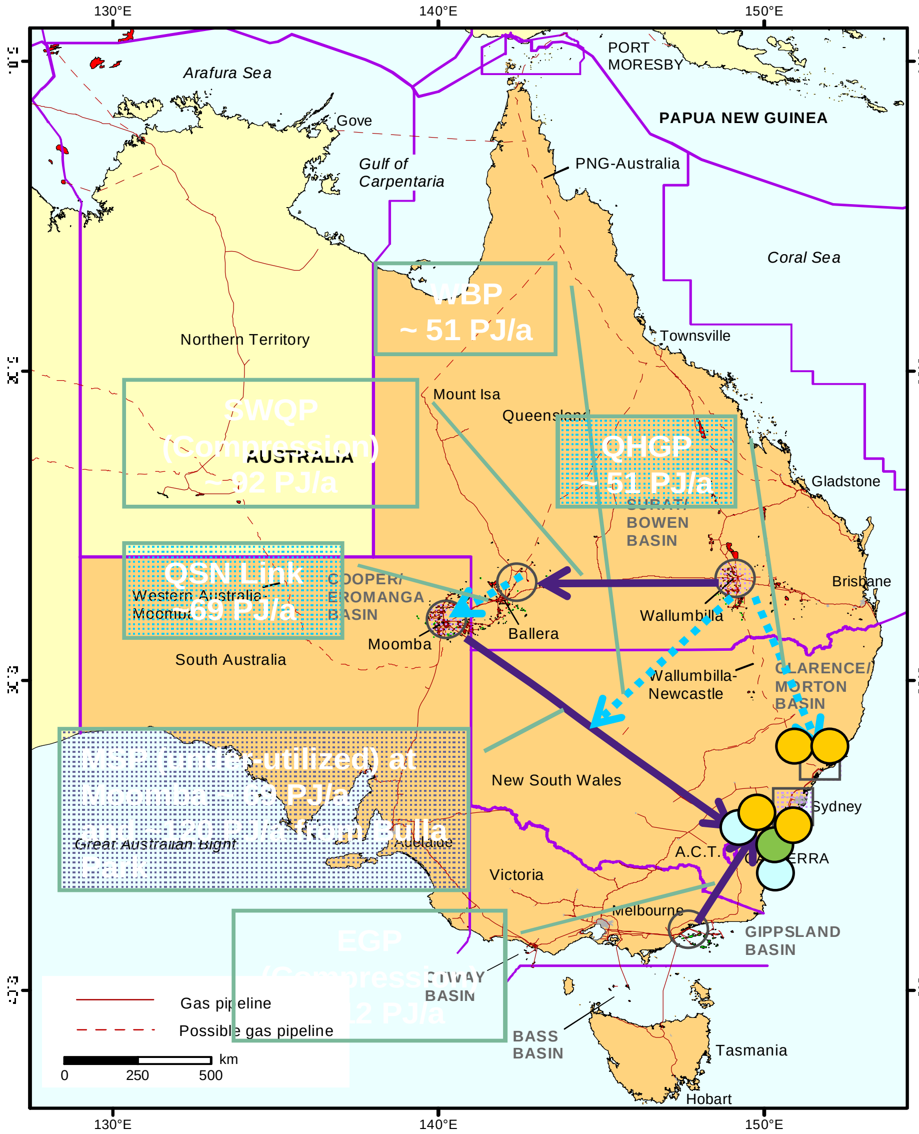
With continued growth in gas-fired generation demand post 2020, additional pipeline capacity would be required from 2024, and this could be met by further pipeline expansions (including looping) but could also be met if indigenous NSW gas supply is larger than our forecast.

Based on these pipeline developments and the future gas supply locations, we have illustrated the locations of potential CCGT developments in NSW, represented as follows;

- Green Dot – Tallawarra (under construction)
- Light Blue Dots – Assumed development of the possible Marulan and Bamarang gas-fired generation pre-2013
- Yellow Dots – 4 x 500MW gas-fired generators 2013 to 2016

Each CCGT would be based proximal to the main gas transmission line due to the relatively large load requirements. There would be additional cost for transporting gas on the distribution system.

Location of Gas Baseload Generation in NSW



Source: Wood Mackenzie

Our analysis shows that 6 new CCGT baseload developments (in addition to the Tallawarra power station) could be supported, with two each on the EGP, MSP and QHGP pipelines in the period from 2010 to 2016 (ranging 400 to 500MW CCGT's).

5. Gas Supply Contracting for NSW Generation

5.1 Gas contract terms

The price for gas sold under contract in Eastern Australia is usually a confidential agreement between the gas suppliers and the gas buyer. The gas price negotiated may be fixed for the term but is more likely to have some annual escalation (generally linked to CPI) and/or a price review at pre-determined intervals over the life of the contract.

Despite the confidentiality of gas contracts in Australia, Wood Mackenzie has a broad insight into the likely gas price of contracts in Eastern Australia based on our in-depth market knowledge, and generalised feedback from the key players within the market (both upstream operators and participants alike).

The current upstream price of gas in Eastern Australia falls between A$2.00 per GJ and A$3.50 per GJ. This broad range is a result of number of factors including;

- The time of the contract signing (contracts have been signed in different years across a variety of market conditions);
- Different contract terms such as contract volumes, firmness of supply, take-or-pay conditions, flexibility in daily quantity;
- Location of the supply source relative to the available market and competing supplies (transportation differentials); and
- Supply risk (the level of certainty on reserves and production for a supply source).

5.2 Recent contracts for generation

Some of the key contracts supporting base load gas generation projects in Eastern Australia in recent years include;

- International Power with BHP Billiton for gas supply to the Pelican Point 490MW CCGT in Adelaide. This gas agreement is believed to have a term of at least 10 years with a total supply volume of 279PJ. The gas is supplied from the Minerva Gas Project in Victoria.
- Enertrade with CH4 (now Arrow Energy and AGL) for gas supply to Townsville. Enertrade supplies gas to three major users including Transfield, the operator of the Yabulu gas-fired power station. The gas contract is for 15 years and has a maximum contract volume of 290PJ.
- TRUenergy – TRUenergy uses a portfolio of long term gas contracts to supply their gas-fired generation needs which included the Torrens Island Power station in Adelaide (recently sold to AGL). TRUenergy are currently building the Tallawarra 420MW CCGT in NSW and this will also be supplied from their portfolio of supply.
- Origin Energy – Origin recently announced the go-ahead for their Darling Downs CCGT in Queensland. Gas will be supplied directly from Origin's CSG upstream gas portfolio although they may also buy some gas from joint venture partners.

In Eastern Australia, large gas contracts still tend to be for terms of 10 to 20 years. Origin Energy recently announced a new gas contract with Rio Tinto Aluminium for a 20PJ *per annum* contract over 20 years (from Origin's CSG projects). These long term contracts help underpin the producers investments in developing the gas production (as well provide the security of supply for the buyers projects). Therefore it is likely that producers would be willing to sign long term contracts to support a CCGT power station development in NSW in the future.

With a load factor of 75%, the variability in annual and daily swing in volumes for a CCGT could be managed with a standard 80% load factor and 80% take-or-pay gas contract. However with a lower load factor of 50%, this type of gas contract would be much more difficult to manage and would incur additional cost such as storage, pipeline flexibility and/or offloading of excess gas supply.

The gas-on-gas competition in recent years has ensured that gas is competitive with coal for intermediate and baseload generation in most states. However, the higher transportation cost of gas to NSW does create a disadvantage for gas versus coal in this state. NGAC's have assisted gas become more competitive with coal in NSW. Longer term, gas will need the support of a carbon price to remain competitive with coal.

6. Delivered Gas Price Outlook

Wood Mackenzie's gas price outlook is based on an assumption that rational economic investment decisions would be made based on cost and price. To the extent that market impediments or distortions exist, this will impact investment decisions and distort the gas price outcomes. Some of the market distortions include;

- The level of Government ownership of the retail sector in NSW;
- The level of participation of Government owned generators in new-build capacity in NSW;
- The Government mandated outcome for the technology for new-build generation in NSW.

6.1 Delivered Gas Price Forecast Assumptions

The increase in competing sources of gas supply, together with the interconnection of the states through gas transmission, has lead to the convergence of regional gas pricing in recent years. Gas-on-gas supply competition now occurs on an interstate basis. Gas market prices in Eastern Australia reflect the differences in transportation distances from the competing supply hubs to the city-gate markets. As a result, gas prices in NSW and South Australia are higher than the gas prices in Melbourne and Brisbane.

The delivered gas price to NSW is based on both the commodity price and transportation cost. For the forecast period, Wood Mackenzie has analysed the factors that will drive changes to these price components. In regard to the transportation cost, the following assumptions were used;

- The transmission tariff is based on full firm supply tariff adjusted for load factor (at 75% and 50%)
- Pipeline expansions and new build tariffs estimated based on current cost estimates and industry accepted economic returns
- Sequencing of pipeline expansions and builds based on Wood Mackenzie analysis (recognising that valid alternatives are possible)
- Gas load for new gas-fired generation will provide the incremental demand to support development of the required new pipeline infrastructure.

It is important to recognise that other factors will determine the price at which gas transportation agreements will be written and therefore a negotiated tariff could be less than our return based calculated tariff.

The commodity price of gas at the key supply hubs is based on an average price for the producing projects around that hub. We have assumed that contracted supply would have 80% take-or-pay and 80% load factor terms to enable sufficient flexibility to manage the 75% load factor gas-fired generation requirement. Addition costs to the commodity price would be incurred in order to manage a gas-fired generator with 50% load factor. These costs would include such services as storage and/or pipeline park-and-loan. We have not included an assessment of these costs in our analysis.

In providing the forecast delivered gas price under each scenario, we have taken into consideration the factors influencing the availability and cost of gas supply, the forecast investments required to deliver gas to the required generation locations and the relative competitiveness of gas versus coal for generation in NSW. We have assumed that a Carbon Trading scheme will be implemented in Eastern Australia by 2010.

6.2 Generation Economics

Gas and coal fired generation are the most economically viable technologies that can achieve the scale and timing for development required under the scenarios being assessed for NSW. Therefore, in order to compare the relative competitiveness of new gas-fired generation versus coal-fired generation, it is important to compare the respective Long Run Marginal Costs (LRMC).

We have compared the LRMC of baseload gas-fired generation with black coal generation under a fixed 75% load factor. The capital cost of a new coal-fired generation is large compared to a CCGT. With the recent escalation in the cost of labour and materials, there is a large uncertainty as to the current cost of a new coal-fired generator. We have therefore assessed two cases (Lower and Upper) for coal fired-generation to illustrate this uncertainty.

- Coal_Lower represents the lower-end cost estimate for new coal-fired generation ($1,400/kW Capital cost and variable cost $10.20/MW based on a coal price of $0.90/GJ)
- Coal_Upper represents the high-end cost estimate for new coal-fired generation ($1,950/kW Capital cost, variable cost $14.60/MW based on a coal price of $1.10/GJ).

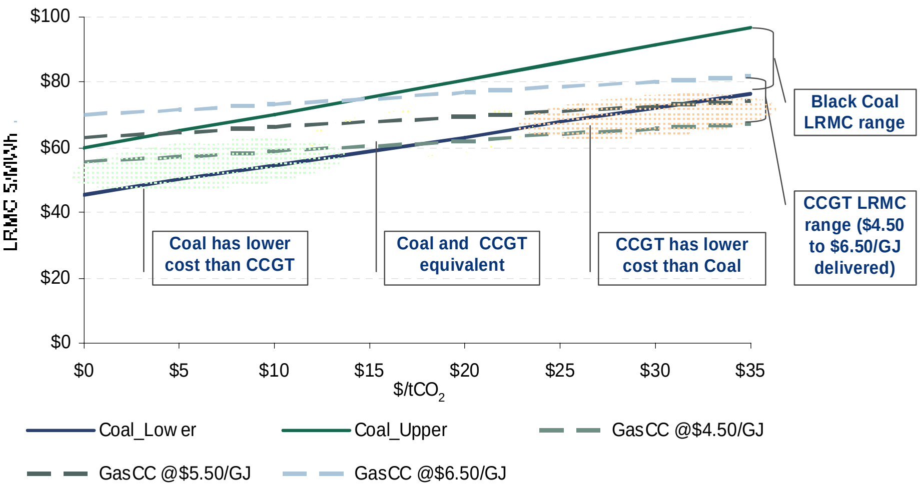
The resulting LRMC for coal represents a range of approximately $15/MWh.

As the capital cost is significantly lower for a new CCGT than it is for a new coal-fired plant, there is greater uncertainty with the variable component of the LRMC of a CCGT. We have therefore analysed the LRMC for CCGT under three delivered gas costs;

- $4.50/GJ;
- $5.50/GJ; and
- $6.50/GJ

The impact of a possible Carbon Trading Scheme is also an important consideration in this LRMC analysis. Gas-fired generation is a lower emitter of Carbon Dioxide then Coal-fired generation. As such, the price of carbon under a Carbon Trading Scheme will impact the relative economics of these two fuels. We have provided our LRMC comparison under a range of Carbon prices from $0/tCO_2$ equivalent up to $35/tCO_2$ equivalent.

LRMC of Black Coal versus CCGT (75 % LF) under different carbon signals and different delivered gas prices



Source: Wood Mackenzie

Summarising this broad comparison of coal versus gas-fire generation LRMC;

- New gas-fired generation under current delivered gas cost (~$4.50/GJ) would not be competitive against new coal-fired generation in NSW without some form of additional support (e.g. NGAC's).

- With NGAC's or a carbon price of approximately $15 to $20/t$CO_2$ equivalent, a delivered gas cost up to $5.50/GJ could compete with new-coal-fired generation.

- With a carbon price >$25/t$CO_2$ equivalent, new coal-fired generation is not competitive against new gas-fired generation, unless the delivered gas cost is >$5.50/GJ.

This broad comparison on similar terms provides some insight to the relative economics of gas and coal for new baseload generation in NSW. However, it is the future cost of delivered gas to NSW that is key to understanding the suitability of gas for baseload generation in NSW.

6.3 Delivered Gas Price Forecast

In 2006, gas contributed to approximately 6% of the total electricity output in Eastern Australia. This relatively small share of the electricity fuel mix is a result of the traditional reliance on low cost coal for baseload generation in Eastern Australia and the use of gas mostly in peaking to intermediate generation. However, in the future, gas is forecast to increase its contribution to the electricity fuel mix. This is a result of a number of factors including;

- Environmental and Social Issues – Gas is a lower emitter of greenhouse gases and therefore is perceived to be more environmentally friendly than coal fired generation. With the possible implementation of a Carbon Trading Scheme, gas should benefit more than coal in the development of future generation.

- Flexibility – Gas-fired generation is generally more flexible and suited to intermediate generation than coal fired generation.

- Availability – The increase in number of sources of gas supply and supporting infrastructure provide a greater opportunity to develop generation projects than has been the case in the past. In addition, with a lesser footprint than a coal-fired plant, a gas-fired plant may be seen as less intrusive in more populated locations.

Wood Mackenzie forecasts strong gas demand growth in Eastern Australia over the next two decades, driven by the increased use of gas in generation. However, this gas demand growth is strongly dependent on the competitiveness of gas relative to coal in generation (even with implementation of a Carbon Trading Scheme).

We have derived a range of delivered gas price forecasts (commodity plus transportation cost) for the New South Wales market, with the following demand cases (for gas-fired generation at 75% and 50% load factors):

- Business as usual;

- 1,000MW of gas-fired baseload power generation in NSW;

- 2,000MW of gas-fired baseload power generation in NSW; and

- 2,500MW of gas-fired baseload power generation in the NEM.

The derived gas price forecasts took into consideration the cost of gas supply (commodity and transportation), the relative competitiveness of gas versus coal for new generation (LRMC), proposed carbon pricing and the level of gas-on gas competition between gas suppliers. Initially, we expect a continuation of strong gas-on-gas competition between gas producers for new incremental demand. However, as gas demand increases through gas taking a larger role in the fuel supply for electricity, the gas-on-gas competition is reduced (as producers have committed their supply). Gas producers are expected to be able to achieve higher prices for the next incremental supply volumes. With a price for carbon likely to be imposed on generation in the future, the competitiveness of gas versus coal will be benefited. It is expected that producers will be able to increase the price which they sell gas up to the point where the alternative (new coal-fired generation) starts to become attractive.

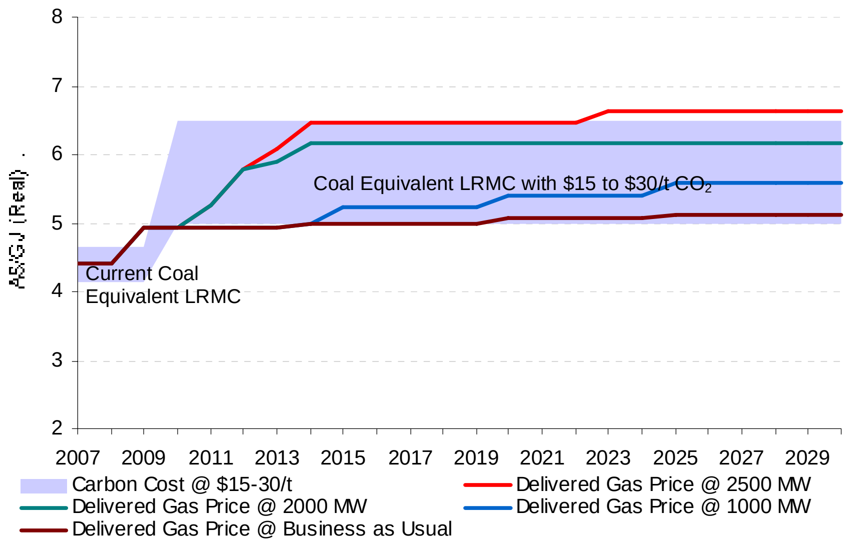
To illustrate the relative competitiveness of each of our delivered gas price forecasts with coal-fired generation, we have highlighted the range (blue shaded region of the following graph) in which delivered gas prices equal the LRMC of new coal-fired generation (with Carbon Cost ranging \$15 to \$30/tCO_2 equivalent). For example (post-2009)

- At a \$5.00/GJ delivered gas price (and \$15/tCO_2 equivalent cost of carbon), the LRMC for a new CCGT would be equal to the LRMC of a new coal-fired plant

- At a \$6.50/GJ delivered gas price (and \$30/tCO_2 equivalent cost of carbon), the LRMC for a new CCGT would be equal to the LRMC of a new coal-fired plant

Note: our LRMC of new coal plant utilised the mid-range capital cost estimate for new coal-fired generation capacity (\$1,680/kW capital cost). The LRMC analysis was also undertaken with the coal-fired generation at 85% capacity, a more realistic level for a coal-fired plant.

NSW Delivered Gas Price Forecast at 75% Load Factor



Source: Wood Mackenzie

Under the Business as Usual Scenario, we expect a limited increase in delivered gas price into NSW for the forecast period. With gas supplies required from Wallumbilla to replace declining Cooper Basin production, pipeline augmentation is required by 2009 including, compression on the SWQP and building of the QSN Link. This is expected to have an added cost impact in that year. Upstream producers will have limited scope to increase gas prices as gas would start to become uncompetitive with coal generation when competing for the first increment of generation in NSW in 2013. We would expect an initial price of carbon in the order of \$15/tCO_2 equivalent if a Carbon Trading Scheme was introduced. This would limit the delivered gas price to \$5.00/GJ if gas was to be competitive with new coal-fired generation on a LRMC basis.

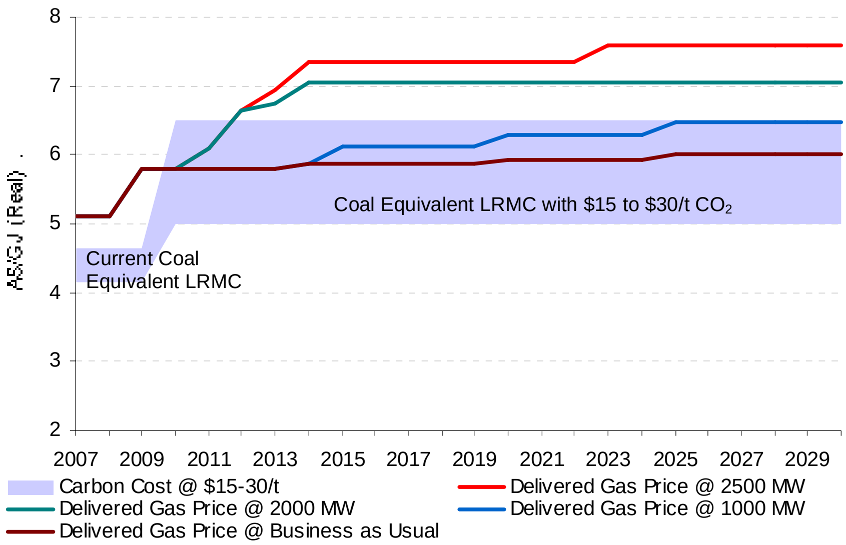
In the 1,000MW gas fired scenario, a new-build pipeline is required from Wallumbilla to NSW. In addition, with two gas-fired plants in NSW, gas prices are likely to increase as supply starts to tighten around 2014. Further prices rises are possible with the increase in the price of carbon above $15/tCO_2$ equivalent.

Under the 2,000MW and 2,500MW gas fired generation Scenarios gas demand will increase both the tightness of gas supply as well as incur the cost of the required transmission augmentation to deliver this gas to NSW. These scenarios are likely to cause a step-change in delivered gas price to NSW, pushing the boundaries of the competitiveness of gas versus coal for generation in future years. The level of carbon price will be a key driver for the level at which the delivered gas cost will rise to but at $30/tCO_2$ equivalent, the delivered gas price could rise to $6.50/GJ and still remain competitive with coal on a LRMC basis.

Other key aspects that need to be considered based on these results include;

- The inferred electricity price differential between NSW and other states such as Queensland, where the delivered cost of gas is much lower
- The trade-off between gas transmission versus electricity transmission and the security of electricity supply based on interstate electricity importation and indigenous generation
- The possible growth of indigenous gas production in NSW that could reduce the need and cost for gas importation
- Possible competitive premium to encourage gas sales into NSW

NSW Delivered Gas Price Forecast at 50% Load Factor



Source: Wood Mackenzie

Under the 50% Load Factor, gas is significantly higher as a result of the cost of reserving firm gas transportation rights but utilising less throughput. However, it is important to recognise that this coal fired generation at 50% load factor is a very inefficient operation (we have not adjusted out LRMC comparison to account for this). Gas fired generation does have the flexibility to operate at this lower lever of load factor and would be more ideally suited in regard to operational reliability than coal, if required.

6.3.1 Implications of proposed LNG projects for future gas price in Eastern Australia

Santos and Arrow Energy have recently announced proposals for LNG projects in Gladstone. A summary of the proposed projects is provided in Appendix I. The key drivers for both Santos and Arrow Energy in proceeding with their proposals for LNG projects in Gladstone are the potential for earlier monetisation of their significant CSG resources and the possibility for a higher net-back price for their produced gas. In particular, it is possible that by creating the opportunity to sell gas for a higher netback price from an LNG development, that there will ultimately be a linkage of the Eastern Australia gas price to an equivalent LNG net-back price.

If either of these projects were to proceed, there is no doubt the local gas price would come under upward pricing pressure. However, there are a number of other factors that will come into play that could reduce the degree of future linkage to LNG netback pricing including;

- The future growth in the domestic gas demand is strongly dependent on the level of growth in gas-fired generation development. If gas prices rise too high, gas will be less competitive with coal for generation and future gas demand growth could be limited.
- The ability to bring on incremental CSG production at relatively low cost has created the strong environment for current growth in CSG supply. With increased gas prices, CSG should become a more attractive investment, ensuring strong gas-on-gas competition remains.
- With strong gas-on-gas and coal-on-gas competition, the linkage to an LNG netback price is weakened.

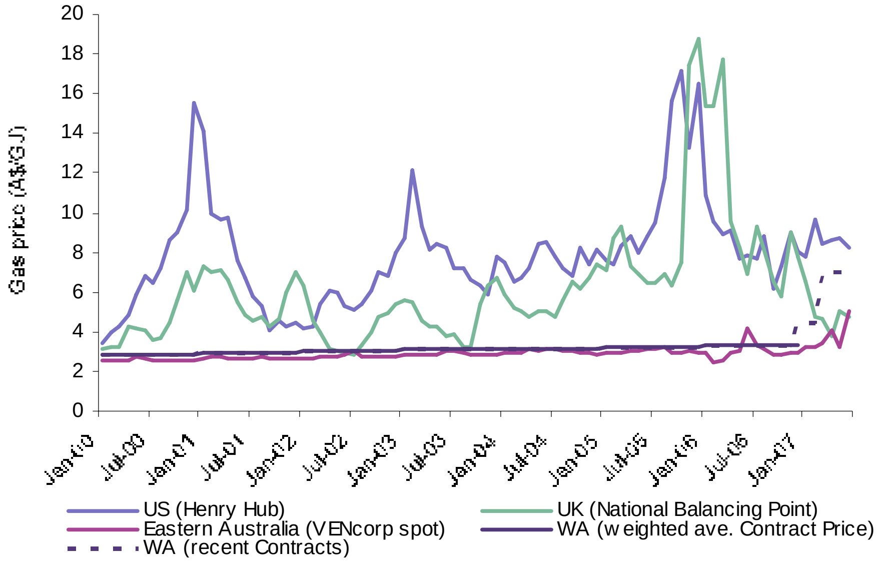
The recent announcements of Arrow Energy and Santos for proposed developments of an LNG export facility at Gladstone underline the growing confidence in the potential of CSG as a large volume, long-term gas supply source. Creation of a future LNG export link in Eastern Australia would likely place upward pressure on gas prices. However this would be tempered to a degree by the level of gas-on-gas competition and the relative competitiveness of gas as a fuel for electricity generation.

6.4 International Gas Price Comparison

Whilst the historical gas price is no indication for future gas prices, it is interesting to compare the gas price in Victoria (Eastern Australia's only transparent gas marker) with Western Australia and the international markets of the United States (US) and United Kingdom (UK). Note, in this comparison the Western Australia gas price is based on yearly weighted average contracted prices except for the last 6 months where we have included some recent, small volume, contract prices.

Both the UK and US gas price show a higher level of volatility and absolute price compared the Victoria and Western Australia gas prices. This is due to the strong linkage of the gas price to the oil price in the US and to a lesser extent in the UK. The UK's lesser link to the oil price is partially seasonal in nature, with the summer periods having strong gas-on-gas competition and lower demand contributing to a de-linkage with oil pricing. Whilst in winter gas is imported from Europe which has a strong linkage to oil price

Victoria and Western Australia Gas price compared to the US and UK



Source: Thomson DataStream, Vencorp and Wood Mackenzie

Victoria and Western Australia by contrast have no linkage to the oil price. With gas competing with coal in the electricity market the gas price has been relatively low compared to other regions of the world. Western Australia illustrates a significant upturn in gas price over the last six months. This is based on a few new small contracts that have achieved significant prices in a tight supply market. Possible future indirect linkage of the gas price to oil price in Western Australia could evolve due to the development of the LNG export industry.

In Victoria, recent increase in the spot price has been a result of significantly higher gas demand for generation as a result of the droughts effect on electricity prices. With increased gas production due to come online (Otway Gas Project) and the breaking of the drought, we expect the gas price to return to more normal levels reflective of the contracted gas market price.

7. Security of Gas Supply

The term security of supply is widely used to cover a range of issues spread over different time frames. It is important to define precisely what we mean by security of supply in order to enable us to compare different markets in a consistent manner. Our classification defines three distinct categories:

- **Operational** – This relates to the ability to maintain continuity of supply on a daily basis, for example in the face of exceptional demand. Operational security is primarily an "intra-State" requirement, and the demand profile is a very important variable in this regard (e.g. proportion of seasonal residential demand, volume of interruptible load, etc).

- **Strategic** – This is the ability to withstand a significant unexpected interruption of a major source (e.g. Longford or Moomba), and is therefore often the most sensitive issue and of greatest concern to governments. Those markets that are heavily dependent on one source or physical link need to seek strategic measures that can be introduced to mitigate the impact of such an event.

- **Longer-term** – In the future there is inevitably uncertainty about the precise availability of gas supplies, in terms of where it will come from and the cost of such supplies. For Eastern Australia, in the long term, the existence of gas reserves should not be a principal concern, rather it is the cost of delivering gas to market that is important.

The tragic events in Victoria during September 1998, when a serious explosion at the Longford gas processing and crude stabilisation plant suspended production, and led to curtailment of gas supplies to all consumers, highlighted the vital importance of strategic security of gas supply. The outage had forced shutdown of 95% of Victorian supply (with the NSW interconnect only able to supply 5% of peak demand) and demonstrated the level to which Victoria was dependent on Bass Strait gas output at the time. Whilst partial restoration of supply to the market took 9 days, it took more than 19 days for supply to be restored to households. However, the full plant restoration took longer than 6 months.

An equally serious fire on the 1st January 2004 led to the shut down of the Moomba gas plant in Southern Australia. Gas plant production was suspended, significantly impacting gas supplies to NSW and South Australia. However the impact on these markets was much reduced as alternative gas supplies were available from the Eastern Gas Pipeline and the SEAGas Pipeline. The SEAGas pipeline fortuitously had only recently been constructed and was under-going commissioning tests at the time of the Moomba fire. The Moomba facility was recommenced on 27th of January 2004. However, it took eight months to restore plant supply back to full capacity.

The Ministerial Council of Energy (MCE) has been working with industry in the development of arrangements for a national gas emergency response protocol for major supply disruptions. The MCE established a Memorandum of Understanding in relation to national gas emergency protocol (including use of emergency powers) in October 2005. The protocol seeks to minimise the impact on the economy and community of disruption to gas and electricity supplies by providing a more coordinated and efficient management of major gas supply shortages.

The MCE has sought to accelerate the development of a more reliable, secure and competitive national gas market. The continued move towards a liberalised and deregulated gas market will be enhanced by promoting such an environment. For example, the construction of the Eastern Gas Pipeline and the SEAGas pipeline provides New South Wales and South Australia, respectively, with alternative sources of supply, leading to greater diversity and enhanced security of supply, even though this was not the explicit intention of either project. The establishment of competition in downstream gas markets has encouraged the development of new sources of supply.

We have summarised below three potential types of incidents related to gas supply security that could impact gas supplies to NSW, the level of market impact and the likely timing to restore supply.

- Offshore Platform
  - o A major platform incident could result in a long-term supply disruption
  - o Catastrophic event could disrupt supply for 2 - 5 years (if platform or pipelines need to be replaced)
  - o Impact could be up to 70PJ/a if one field was affected
  - o Market supply impact is relatively small but potentially with long term effect

  There has not been a major platform incident in Australia of the kind described here. Internationally these events are also rare. The Piper Alpha platform explosion/fire in the North Sea (UK) is one example of this type of catastrophic event and fire that resulted in the complete destruction of the production facility and the tragic loss of many lives. The lessons learnt from this incident have been applied world-wide to improve the level of safety on offshore production facilities and reduce the risk of this event occurring again.

  In Eastern Australia, the development of new gas supply sources in recent years has reduced the significance of any one particular offshore gas field for supply. The increased development of onshore CSG projects will also help diversify supply risk to this type of event.

- Processing Plant
  - o Processing plant incident could result in short to medium term supply disruption
  - o Up to 1000 mmcfd of capacity could be lost out of the system (although in the future, only Longford will have this scale with most other gas plants in Eastern Australia having supply deliverability less than 300 mmcfd)
  - o Impact could last weeks to months (e.g. 1998 Longford gas outage – Partial supply restoration took 9 days, while full plant restoration took greater than 6 months)
  - o Market supply impact is large but potentially short term effect (of major disruption)
  - o Over the last 30 years, there have been two events of this type and scale in Eastern Australia
  - o With more plants and infrastructure, future impact is reduced

  The risk of major gas supply disruption from a potential processing plant incident in the future has been reduced in recent years with the development of new gas supply sources and infrastructure. The reducing dominance of supply from Longford and the Cooper Basin plants (Moomba and Ballera) is illustrated by their reducing market share of gas supply. In the year 2000, the Longford, Moomba and Ballera gas plants supplied 92% of the total Eastern Australia gas market. By this year (2007), these three plants will supply approximately 60% of the total market and this is forecast to fall to just under 40% by 2013.

- Pipeline
  - o Pipeline failure could cause short to medium term supply disruption
  - o Could take up to 400 mmcfd out of the system
  - o Impact could last days to weeks
  - o Market supply impact is large in the short term

In 1982, the Moomba to Sydney pipeline suffered an explosive rupture as a result of corrosive fatigue in the pipeline. Pipelines today are now routinely examined with sophisticated technology to monitor corrosion and fatigue. Preventative action such as replacement of sections of the pipeline may be required. However with routine monitoring, testing and maintenance, the risks of this type of event are significantly reduced.

Whilst each of these types of incidents can clearly have a significant impact on the security of gas supply, the risk and impact on the market today is significantly less then it was a decade ago. With continued market development, investment in infrastructure and supply, this supply security risk and impact will be reduced further still. The added benefit is a more dynamic and competitive gas market.

8. Conclusions

Concerns for the future gas supply for Eastern Australia have been raised in recent years based on the forecast decline in the Cooper Basin and the decision by the PNG Gas Project partners not to proceed with developing gas supply from Papua New Guinea to Queensland. However, rather than a bleak-outlook for future gas supply in Eastern Australia, Wood Mackenzie's analysis shows a gas industry that has demonstrated a very healthy growth in gas reserves and supply in recent years. The upstream industry in Eastern Australia has delivered a reserves replacement ratio of 260% over the last five years – a level indicating significant supply growth potential.

In particular, CSG reserves have grown from less than 500PJ to around 4,000PJ in the corresponding period. CSG is now generally accepted in the industry as a reliable source of gas supply (typified recently by Rio Tinto Aluminium's contract with Origin Energy for 20PJ/a over 20 years to supply the expansion of their Gladstone Alumina refinery). Wood Mackenzie forecasts that CSG production potential is such that by the end of next decade, CSG could account for more than 50% of the total gas supply in Eastern Australia.

Under the generation Scenarios provided by the Owen Inquiry Secretariat, the potential to increase the level of baseload gas fired generation in the state in the period to 2016, is substantial. The required gas supply to meet this forecast gas demand would be predominantly from Victoria and Queensland and would require expansion of existing gas transmission, as well as new pipeline investment. In particular, there is a need to develop a gas pipeline directly from Wallumbilla to supply gas into NSW. This pipeline could connect to Newcastle and/or Bulla Park in central NSW. This new pipeline would complete an important loop in the gas transmission system that would improve overall security of gas supply as well as support exploration and development of potential new gas supplies within NSW along the pipeline route.

Wood Mackenzie's analysis indicates that there is likely to be sufficient gas supply available to meet this demand out to at least 2020. Whilst beyond 2020 there is greater uncertainty, the CSG industry continues to increase gas reserves at an impressive rate and the ultimate potential of this industry in Eastern Australia could be enormous (with potentially decades of supply). There is scope for additional gas to be discovered and developed in the intervening period from conventional sources. Ultimately the option exists for importation of gas from Western Australia by new pipeline or as LNG. There is also scope for demand growth in this period to be reduced as new gas fired generation options switch to alternative fuels/technologies, delaying the requirement for long distance supply.

Environmental and social benefits exist with the choice of gas over coal generation. These include reduced greenhouse gas emissions, lower development footprint and lower water use. With the development of gas fired generation, gas supply security will be enhanced as additional gas transmission is developed and indigenous gas supply encouraged. Whilst still to be proven commercially, the indigenous gas supply of NSW has the potential to grow dramatically and reduce the need for interstate gas importation in the future.

Gas is currently not competitive with coal for baseload generation in NSW without NGAC's. This is a result of the additional cost of transporting the gas from inter-state. However if a Carbon Trading Scheme were to be introduced, gas could be competitive for baseload generation in NSW at a cost of carbon in the range \$15 to \$30/t CO_2 equivalent. Under the High Gas Demand Case, delivered gas prices will rise, with the price of carbon ultimately determining the level at which gas prices compete with coal for future baseload generation.

Appendix I - Proposed Eastern Australia LNG Projects

Santos' LNG Proposal. On the 18th of July 2007, Santos announced a proposal to construct a 3-4 million tonnes per annum (mmtpa) liquefied natural gas (LNG) facility at Gladstone. Santos will now embark on detailed engineering and environmental studies as well as preliminary marketing of the LNG. A Final Investment Decision is planned by the end of 2009 and would enable construction to proceed with first gas cargoes by early 2014.

Santos estimate the capital cost in the range of A$5-A$7 billion (including upstream development, liquefaction plant and associated infrastructure). The annual gas supply volumes required would be in the range of 170-220 PJ *per annum*. The total volume of gas required to support an LNG scheme of this scale (assuming 20 to 25 years supply) is estimated to be between 4,000 and 5,500PJ.

It is important to note that Santos have only proposed to enter into detailed evaluation at this stage. In addition to the studies, they will also need to establish sufficient gas reserves to allow them to sign long-term LNG contracts. This reserves certification will run in parallel to the studies. Santos have indicated that they will be using CSG gas from their Bowen and Surat Basin fields. With the scale of reserves required in the order of 5,000PJ, this would require a significant increase to Santos' current CSG gas reserves.

Santos are currently assessing the Gladstone LNG project on their own. Santos does have some experience with LNG through their equity in the Darwin LNG Project, although they have not operated or developed an LNG project in their own right. Santos could potentially bring in other partners as plans progress, including a partner with LNG development and operating experience.

Arrow Energy's LNG Proposal. On the 30th of May 2007, Arrow Energy announced it had signed a HOA with LNG International Pty Ltd ("LNGI"), to supply gas to a proposed LNG facility to be located within the Gladstone Port area and designed to produce approximately 1 mmtpa of LNG (with an option to expand to 2 mmtpa). The annual gas supply volume required for a 1 mmtpa LNG Train is approximately 55 PJ *per annum*. Arrow Energy have stated that the initial supply to the LNG terminal under the HOA is for a period of 12 years, commencing in late 2010. An option to supply a further 55 PJ *per annum*, starting as early as mid 2011, subject to the second LNG train being developed. Arrow Energy are targeting a gross reserves volume of 1,100PJ to support the initial LNG Train development of this project.

In addition to the smaller scale of this LNG project, the ownership structure is also different to the Santos' proposal. Arrow Energy currently only intends to sell the gas to the LNG project that would be developed by LNGI. Arrow Energy has indicated it could act as aggregator of gas supply from other sources including its joint venture partners.

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Report to the Owen Inquiry:

Securing Private Investment in New Generation in New South Wales

August 31, 2007

Morgan Stanley

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Main Cover Photo: Private Sector Investment: International Power's Pelican Point Power Station, South Australia

Photo Courtesy International Power

International Power began operations in South Australia in 1999 when it developed and constructed the State's first major private sector power station at Pelican Point, 20 kilometres north-west of the Adelaide central business district. The Pelican Point power station uses a combined-cycle gas turbine operation to produce 485 MW of electricity. Pelican Point has an energy efficiency of more than 53%, compared with older power stations which can be less than 35%, which in turn reduces greenhouse gas emissions per unit of energy consumption.

Key Findings and Recommendations

To optimise conditions for private investment in new power generation developments in NSW, the State of NSW would be best served by divesting itself of both its electricity retail businesses and power generation interests, and transferring existing greenfield generation development sites to the private sector. This will ensure that the private sector develops the generation capacity to secure supply for NSW electricity consumers into the future.

Prior to the introduction of electricity markets in Australia and elsewhere, government over-invested in capacity to deliver reliability. Market systems were then introduced to deliver investment efficiently. A 'half-market' that attempts to combine the old and new by continuing with significant government direction of investment is no market at all. Private sector investment will inevitably fail under such conditions. To ensure private sector investment in the National Electricity Market in NSW, the NSW Government needs to create a fully functioning market by divesting itself of both generation and retail interests.

Divesting itself of both retail and generation interests would:

- Create incentives for investment by the acquirors of the retail businesses seeking to hedge their retail exposure
- Create incentives for investment by the acquirors of the generation businesses seeking to develop their generation portfolio over time
- Maximise the number of parties with incentives to invest, and provide both retailer and generator investors with the right incentives to invest
- Maximise the competitive nature of the post-transaction market to the benefit of consumers and the economic development of the state; and
- Help ensure the maximum reliability and efficiency of the electricity system in the future

A divestment of retail is simply an acceleration of what will otherwise occur over time through retail contestability, but with value captured up front for NSW taxpayers rather than eroded over time. The current business model of the NSW Government-owned retailers is obsolete, and could not be updated to be fully competitive with the business models of the private sector without the state spending several billion dollars of taxpayers money on power and gas assets to make the current retail businesses truly sustainable and competitive over the long term.

A divestment of generation interests could be effected by way of sale, or by way of long term lease of the generation assets but with the state retaining the legal ownership of the assets.

An IPO of one retail business combined with selected generation interests could create a viable competitor to the incumbent private sector players and should be considered alongside other divestment options, with the NSW Government having the ability to move forward with the best option(s) at the appropriate time.

Divesting the existing NSW Government-owned development sites suitable for new generation will provide the private sector with the greatest number of options for new development and some of the most prospective development sites.

Key Findings and Recommendations (cont'd)

The process of transferring retail and generation interests to the private sector must commence in 2008. Peak generation is required early next decade. Baseload generation will be required mid-next decade, and realistic development timelines for new coal-fired generation span around six years. In order that coal, gas and any other viable technologies can be fully considered in an appropriate timeframe, the process of change needs to be implemented as soon as possible.

The private sector is largely an observer of the NSW market under the current industry structure. In order that the private sector instead becomes an active participant and investor in NSW, fundamental change is required to the NSW industry structure. Transferring retail and generation interests largely removes the threat of government sector competing with the private sector for both new investment and in ongoing commercial operations.

Without change, the NSW Government will inevitably have to fund most new generation development for the forseeable future, in a highly competitive marketplace. This funding requirement would come on top of the considerable funding already required for the transmission and distribution poles and wires over the next four years of around $9Bn. Estimates to 2020 of the new generation funding requirement alone are in the order of $7Bn–8Bn, without factoring in emissions related expenditure on sequestration projects and the like, which could easily amount to billions more, and without investing further billions of capital in improving the existing competitive position of the retailers.

This additional capital funding requirement would compete with other government priorities. The NSW Government would prefer private sector funding of new generation, and the private sector is ready, willing and able to fund new generation projects under the right industry structure in NSW.

While the principal issue underlying this report is the conditions for securing private sector investment, the consequences of the NSW Government's decision on the way forward go beyond just consequences for new investment. If the NSW Government wants to continue operating competitive retailing and generation businesses in the National Electricity Market, then it needs to invest considerable sums in ensuring these businesses are able to compete on a level playing field with the private sector, which has direct access to capital. Retaining the existing NSW Government-owned retail and generation businesses, and not investing in them, can not be sustained.

Morgan Stanley

31 August 2007

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Private Sector Investment: TRUenergy's Tallawarra Power Station Under Construction in Mid-2007
Photo Courtesy TRUenergy

TRUenergy is currently constructing a new gas-fired power station near Wollongong, in NSW. Using gas fired combined cycle generation technology for the first time in NSW, Tallawarra will produce 400MW of electricity and be able to react quickly when demand for electricity rises rapidly. The station will produce considerably fewer greenhouse gas emissions than traditional coal-fired power stations. Construction of Tallawarra is scheduled to be completed in Summer 2008/09.

Section 1
Executive Summary

1.1 Introduction

In May 2007, Morgan Stanley Australia Limited ("Morgan Stanley") was appointed to provide advice to the Owen Inquiry's examination of its fourth term of reference.

This fourth term of reference for the Owen Inquiry is to "Determine the conditions needed to ensure investment in any emerging generation, consistent with maintaining NSW AAA credit rating."

The fourth term of reference is not explicitly restricted to only considering baseload generation investment. The first three terms of reference for the Owen Enquiry, namely the need, timing and technology of new plant, are focused on baseload generation. Consistent with the main theme of the Owen Inquiry, Morgan Stanley has had primary regard to investment in baseload generation, but has also considered issues and made comment as they relate to other forms of generation investment.

Morgan Stanley's role was to provide advice to the Owen Inquiry as to:

- The conditions required for private sector investment in new generation in NSW
- Identify the options available to bring about these conditions for investment

Morgan Stanley did not carry out an assessment of the impact of new investment in generation on the NSW AAA credit rating, if this new investment were funded by the NSW Government rather than the private sector. This credit rating work was carried out by NSW Treasury which has the expertise and data to carry out this long-term fiscal modelling.

Our advice is contained in this report ("Report").

1.2 Approach

Morgan Stanley's scope of work required an assessment of a number of interrelated matters:

- Had the private sector delivered power generation, and particularly baseload power generation, in the past in the NEM? If yes, why, if not why not?
- What conditions would be most likely to maximise the development of new power generation on a commercial basis and in a timely manner?
- What conditions might frustrate or prevent new investment in power generation on a commercial basis and in a timely manner?
- Is there anything that distinguished the NSW market from other markets in Australia?
- If lessons could be drawn from offshore markets, good and bad, what were they?
- In seeking to secure new generation and particularly baseload power generation, but funded by the private sector, how should the government behave and how actively should it participate in securing this generation?
- What are the best options available to the NSW Government to establish the conditions most conducive to private sector investment?

In carrying out this assignment Morgan Stanley was less interested in predicting who might be the next investor or what might be the next investment, and more focused on how the market operated as a

1.2 Approach (cont'd)

whole and the associated underpinning commercial drivers of behaviour. Corporate identities and business plans come and go, but it is the fundamental structure of the market and its commercial incentives that will underpin and direct long-term private sector investment behaviour.

1.3 Context

The current industry structure in NSW is unique within the National Electricity Market ("NEM") that interconnects NSW, Victoria, Queensland, South Australia, the ACT, Tasmania and the Snowy region between NSW and Victoria. Tasmania has recently joined the NEM via the new Basslink subsea interconnection. Amongst the mainland states that have been an established part of the NEM for several years, in no other State but NSW does the State continue to own the vast majority of both electricity generation and electricity retail businesses. NSW also continues to own the regulated distribution and transmission networks (poles and wires), as does Queensland.

As a consequence the Government plays numerous and at times conflicting roles in the electricity sector. It:

- Owns and operates three retail businesses which compete against each other and against private sector retailers under Full Retail Contestability ("FRC") rules
- Sets the terms of reference for the determination of the State's retail tariffs
- Owns and operates three generation businesses which compete against each other, with Snowy Hydro and to varying degrees with other generation which supplies power from interstate
- Promotes state development and investment
- Owns and operates regulated monopoly electricity transmission and distribution assets ("poles and wires")
- Makes policy for environmental mechanisms (such as GGAS)
- Is the majority economic shareholder in Snowy Hydro Limited
- Is the authority for the issuing of development approvals for new investment in power stations, coal mines, transmission infrastructure etc.

It is in this unique context, where arms of government are clearly the dominant player at every level of the sector, that the NSW Government established the Owen Inquiry, and tasked Morgan Stanley to report on investment conditions for private sector investment in new generation in NSW.

Private sector investment is an alternative to further public sector funding. The NSW Government has a stated preference to have new power generation funded by the private sector, freeing up public monies for spending on social programs and areas of social infrastructure where the role of the private sector is less developed. We have not been required to examine this stance but have taken it as the logical starting point in our analysis. In this regard we note the stated positions of the NSW Government from which we have extracted the text in Box 1 below.

1.3 Context (cont'd)

Box 1: Stated Positions of NSW Government in Funding

"It is not my preference, or the preference of this Government to use public funds to build new power stations with such funding better used elsewhere such as hospitals and schools."

Source News release issued by the Premier of New South Wales, the Honourable Morris Iemma, 9 May 2007

The NSW Government recognises the importance of adequate, reliable electricity supplies to the NSW economy and to the living standards of NSW citizens. The Government's preference is that the private sector undertakes investment in new electricity generation capacity. If private sector investment is not forthcoming and the Government perceives that there are risks that supply demand imbalances may result in supply shortfalls, then the Government-owned businesses may invest in new capacity to meet that demand. The NSW Government will not allow NSW businesses and residences to suffer from blackouts and supply shortfalls.

Source 2007 NSW Infrastructure report to COAG

In formulating our analysis and recommendations, we have been cognisant that the NSW Government has:

- Shareholder control over the State-Owned Corporations [1] ("SOCs") (within the constraints of the State-Owned Corporations Act 1989) and control over state-based policy settings
- No unilateral influence over NEM-wide issues, but formal influence through the Ministerial Council on Energy
- Influence but no control over other issues such as potential emissions schemes introduced by the Commonwealth Government

We have framed our recommendations reflecting the extent of the NSW Government's control and influence, and so as to attempt to avoid any wider impacts on the operations of the NEM. To its credit, the NEM has coped surprisingly well with a host of different state-based mechanisms in the past. However, the imposition of multiple different instruments on the NEM is far from ideal. While the NEM appears to have dealt with differing state mechanisms to date, in an environment of tightening supply-demand balance, it should not be assumed it will take further potential distortions so easily in its stride.

Proponents of continued NSW Government funded investment in the sector should consider that this increases investment of NSW taxpayers dollars in highly competitive enterprises which are exposed to significant commercial risks, that could be deployed elsewhere:

- The retail businesses owned by the NSW Government are smaller than most of their competitors (excepting Energy Australia which is a large retail business in its own right) and as 'pure' retailers, are locked into a business model that the private sector abandoned several years ago. Without question Government ownership has limited the freedom of development of these businesses. While the private sector electricity players have rapidly changed shape and size around them in recent times, the retail SOCs are essentially unchanged from their form of several years ago, and as such their relative commercial position has deteriorated. Unlike their private sector competitors, these businesses own no generation assets and have no upstream gas reserves with which to manage risk and optimise returns. In the case of Integral and Country Energy, the businesses are almost entirely focused on electricity supply and have few or no gas customers, and do not have the economies of

Notes

1. Country Energy, Delta Electricity, EnergyAustralia, Eraring Energy, Integral Energy, Macquarie Generation. Snowy Hydro is not a SOC and the Government does not control it

1.3 Context (cont'd)

scale possessed by their competitors. The retail businesses are largely (but not entirely) confined to NSW and do not have the diversity of their large private sector competitors. In their current form the value of all of the SOC retailers will inevitably decline in the future under FRC, combined with the current Government ownership model and under ongoing investment constraints. In order to replicate the business model of their competitors, NSW tax payers would have to deploy billions of dollars in power generation and gas investment in competition with the private sector. The retail SOCs face considerable challenges under the status quo industry structure

- The generation businesses owned by the NSW Government compete with each other and privately-owned generators in Victoria, Snowy Hydro Limited, and mixed publicly and privately-owned generators in Queensland. NSW imports significant amounts of power from these other regions of the NEM. Going forward the NSW generators will also compete with increased private sector generation in NSW, although we would expect penetration of private sector generation to remain small in the absence of any widespread sector reform. To date these SOC generation businesses have been almost entirely fired with NSW black coal, with small amounts of gas and hydro based generation. The plant in the NSW generation fleet entered service between 1967 and 1993. In the future, even without investment in new plant, the Government may face considerable capital expenditure on its existing plant motivated by emissions considerations

What became clear during our study is that there is a great desire on the part of potential investors, and the market more broadly, for the Government to set out a clear way forward and implement it with the strongest possible commitment. It is public knowledge that the Government has reviewed the future of the electricity sector several times over the past decade. This process of occasional review has created some uncertainty and has contributed to private sector hesitance around the future investment climate in NSW—it has also created uncertainty inside the SOCs themselves and in some cases has deferred business decisions that the SOCs would otherwise have made. Regardless of the substance of the final Government decision, a clear way forward is required for the private sector energy market participants, fuel suppliers, major consumers and the government business enterprises alike.

1.4 Findings on Conditions

During the Owen Inquiry Morgan Stanley met with numerous parties and considered public and confidential submissions. Based on our discussions and analysis, there are a number of conditions for investment, some of which can be thought of as commercially driven enabling conditions (which facilitate investment decisions), and others which are frequently government policy or process conditions, which can be frustrating conditions that block investment when they exist. Morgan Stanley's findings on the most important conditions for investment are summarised in Table 1 below, and discussed in more detail in Section 4.

Table 1: Findings on Investment Conditions

Condition	Finding	Morgan Stanley Comment
Market Need (See Section 4.2)	The private sector will invest in baseload (or any other) generation when a demonstrable market need can be predicted, and an investment case can be made for economically viable operation and financing In the NEM, this market need is signalled primarily by the level of forward prices and future supply-demand modelling beyond the horizon of reliable forward pricing (around three years), or by way of retailers and/or major customers entering into long-term contracts to underpin investment Non-price based motivations for investment may include the desire for ownership of power assets rather than relying on contract markets, monetisation of fuel resources, or for strategic reasons such as the displacement of competing rival investments, or to support market entry	• General consensus of new baseload requirement mid-next decade—although each player has its own unique perspective (which is to be expected) and a range of projected required dates of initial operation spanning from 2012 to 2017. The range of views reflects different forecasts for demand growth, capacity factors of existing plant, imports from interstate etc. • Immediate investment focus for the private sector in NSW is additional peak and intermediate generation from early next decade • The private sector does not have the business exposure to NSW market currently that would justify building baseload and is more focused on the other (privatised) markets where it has existing exposures • In order to facilitate baseload investment in the middle of the next decade, the NSW Government needs to determine what changes it will make to its current interests in the electricity sector with some urgency. Planning, procurement, tendering and construction periods for a new greenfield power station could span as long as seven years (for coal) and as short as three to four years for gas-fired power stations
Access to a Sustainable Business Model (See Section 4.3)	Investors will seek a reasonably predictable revenue and earnings stream to underpin new investment. There are essentially four business models for new investment in the NEM: 1. Investment by vertically integrated retailer-generators 2. Investment by portfolio generators which already have existing plant 3. Investment in stand-alone plant underwritten by a medium to long-term power purchase agreement ("PPA") with a counterparty, typically a retailer or major industrial consumer 4. Investment in stand-alone "merchant risk" plant Of all of these different models, 1, 2 and 3 offer different forms of risk diversification from the naked "merchant" NEM risk offered by Model 4 which is the least predictable and most risky form of investment	• Relatively few parties appear willing to take a pure merchant exposure on a stand-alone power station investment (Model 4). Not surprisingly, this form of investment has been rare in the NEM • In particular, where a new investor develops a pure merchant plant with a relatively small market share, where the rest of the sector is controlled by a single shareholder as currently occurs in NSW, the returns experienced by the new investor could be perceived to be significantly influenced by factors outside its control and outside the normal operations of the market (see stranding risk below) • PPAs with Government retailers (Model 3 where the Government retailer is the off-taker) are favoured by some generators, as they see it as a means of getting a favourable risk allocation and creditworthy counterparty. However, such a PPA results in Government retailers funding and controlling timing of new plant—this is not "private sector investment". There is less likelihood of PPA funding by private retailers • This leaves two business models which are the most likely to facilitate private sector investment in NSW: – Model 1: Investment by vertically integrated participants with significant retail exposures to hedge

1.4 Findings on Conditions (cont'd)

Table 1: Findings on Investment Conditions

Condition	Finding	Morgan Stanley Comment
		their risks and ensure direct management control over a component of their overall electricity supplies. This business model can only occur in NSW if the private sector is able to acquire the existing retail businesses to create a material retail exposure to the NEM – Model 2: Generators with existing plant and portfolios are likely candidates to build new merchant plant, as they have operational expertise and may have the best access to low-cost development options, and are motivated to bring new plant more smoothly into the market with less overall disruption to market prices. This business model can only occur in NSW if the private sector is able to acquire the existing generation assets to serve as a platform for new investment on a portfolio basis
Access to Fuel and Other Material Inputs (See Section 4.4)	Investors will seek predictable input costs in the medium to longer-term. Costs will largely be commercially determined, and determined by way of contract (e.g. gas or coal supply contracts, construction contracts) Costs can be affected by policy settings. The private sector is unclear how future emissions policies will affect future operating costs, both in the short run and long run, which negatively affects confidence in new investment	• Lack of carbon pricing certainty is a major issue for new coal plant. There is a profound lack of appetite in the private sector to build new coal fired plant, not because of an aversion to coal per se, but because the future emissions regime and pricing remains so unclear • Future gas supply of lesser concern with pricing expected to be competitive with coal, although participants assume market will operate to allow market-wide gas price changes to flow through to electricity prices • Construction costs are perceived to be inflating rapidly, which in particular would affect the capital costs of new coal fired power stations which are more construction-intensive than gas-fired stations • Securing access to plant in the order queues of leading manufacturers is subject to market conditions and availability
Site Access and Planning (See Section 4.5)	Investors need access to a permitted site and supporting infrastructure in a timely manner in order to respond to market developments and install new capacity when signalled by the market	• Development application and environmental planning processes in NSW are seen as more costly, time-consuming and less coordinated than they can be. The new Part 3A process is seen to be an improvement on prior processes, but its implementation needs to be actively monitored to ensure acceptable development timeframes • This not only applies to generation stations—but development of new sources of fuel, such as coal mines and coal seam methane projects or transmission connections, which can also be subject to delays and uncertainties
Availability of Capital (See Section 4.6)	Investors need to attract sufficient capital, and at the right cost, to invest economically	• No perceived capital constraints for the "right" investment—access to capital not seen to be a major issue by the private sector • Baseload seen as an easier investment case than peak (for merchant investment), given that baseload can be relatively assured of dispatch, while peak is not • Many parties see gas-fired generation as an easier investment case than coal, due to lower capital investment, shorter construction time, smaller unit size and optionality (open-cycle closed-cycle conversion)—but this may also somewhat reflect the emissions uncertainty, in that the private sector is not focusing on coal-fired investment at present

1.4 Findings on Conditions (cont'd)

Table 1: Findings on Investment Conditions

Condition	Finding	Morgan Stanley Comment
Stable Policy Environment (See Section 4.7)	Significant market concern about a multitude of competing policies distorting market outcomes, with new policies emerging or existing policies changing on a regular basis across the NEM The lack of clarity on the future emissions regime that may apply to new generation is a large deterrent to investment, and is presently a stumbling block to any new investment in coal-fired plant. This lack of clarity is a policy gap that at present is a key risk to new generation investment—fortunately there is time for this to be resolved before the situation becomes critical, but it is absolutely critical for timely and efficient investment in NSW that it is resolved in a timely manner Financial and commodity markets can measure and trade many different things—but they cannot hedge regulatory and political risks. The only "hedge" is to do nothing and adopt a "wait and see" approach, which has a potential opportunity cost but no cash cost	• The frequency of electoral cycles in the NEM and the proliferation of different state-based electricity and emissions policies are unhelpful in developing a transparent single national market • In electricity markets, these have included amongst others ETEF (NSW), LEP (QLD), GECs (QLD), retail price caps (all states), VRET (Vic.), retail churn incentives (SA) • For example, while the NEM was designed as a national market, electricity generated in Victoria and Queensland, which is indistinguishable from any other electricity, and which might well be exported to the same NSW consumer, is subject to quite different regimes • The proliferation of state schemes will make the transition to a single unified national emissions scheme (if and when it comes into being) more complicated • To ensure timely investment, it is impossible to overstate the importance of clear rules being issued, as soon as possible, in relation to the following key parameters – How will different industries (e.g. trade exposed) be included or excluded – Medium-term emissions targets (say to 2020) which will affect near-term investment returns more than long-term/2050 type targets – Transition rules from existing schemes to a new national scheme – The penalty for noncompliance – The 'red line' in time for when new investment will be 'grandfathered' into the scheme as pre-existing investment, and so be issued with free permits, and when it will not
Commercially-Determined Electricity Prices, Free of Government Interventions (See Section 4.8)	This can be divided into two issues, both material: • Investment behaviour: The possibility of SOCs making "noncommercial" generation investment is a major concern for private sector investment, with consequences of excess capacity for market prices and subsequent stranding of private sector investment • Commercial behaviour: The possibility of SOCs making decisions on contracting, trading etc. that would not normally be made by profit-seeking private sector investors. This is exacerbated by the fact that all the SOCs have the same shareholder and may behave in similar ways	• While it may (or may not) be incorrect, at the same time this is not an irrational concern. The private sector takes as a given that Government will tend to invest early in generation, because political consequences of late investments are not tolerable, and the costs of early investment are not transparent in government-owned businesses (unlike public capital markets), and therefore while early investment comes at a cost to the community, there are few if any visible ramifications • The SOCs currently own a number of attractive sites. The continued development activities of the SOCs, while completely appropriate from their own perspectives and while providing their government shareholder with development options, sends very mixed messages to the private sector in relation to government investment intentions and heightens "stranding" risk perceptions • The private sector electricity market participants remain wary of commercial behaviour by SOCs, particularly during periods of market stress, where high prices may prompt more influence (even if tacit) from Government shareholder. Whether or not this perception reflects reality, the perception itself is the reality, and does affect private sector investment appetite

1.5 Recommended Options for NSW Government Action

By way of introducing our recommendations, we note that in the current industry structure of predominant Government ownership, without any changes being made, we believe the NSW Government will have to fund the next large baseload power station, and is also likely to fund other peak and intermediate generation in the coming years.

The industry structure is not currently established to optimise the potential for new private sector generation capacity.

The private sector views the risk of ongoing government sponsored generation displacing or competing with otherwise profitable private sector investment as high. In recent years the industry has understood that the NSW Government did not want to commit further funds to generation, consistent with the public position highlighted in Section 1.3. However the approval of Delta Electricity's gas-fired peaking power station at Munmorah (the "Colongra" power station) has left the private sector unclear and unsure as to whether the Government will endorse other state-owned generation proposals, and has materially increased the perceived level of stranding risk. We believe the Colongra experience is likely to be repeated in the future under the current industry structure.

Our recommendations have been prepared as a package of actions that, consistent with our brief, will optimise the conditions for private sector investment. In our opinion, implementing all of these recommendations will create the best environment for new private sector investment in NSW. The most critical recommendations that should be implemented in conjunction are Recommendations 1 and 2, namely the divestment of interests in State-owned generation businesses (by sale or long-term lease) and the sale of the retail operations. A retail-only transaction, while an improvements on the status quo, does not create the optimal conditions for private sector investment.

Our recommendations are set out in brief in Table 2 below.

Table 2: Morgan Stanley Recommendations in Brief

Recommendation	Description
1	Dispose of interests in generation businesses and generation sites
2	Dispose of interests in retail businesses
3	Actively monitor progress of reforms to development approval processes
4	Continue to implement scheduled wind-up of ETEF scheme
5	Support the review of effectiveness of retail competition
6	Encourage clarity on national emissions scheme as soon as possible
7	Review the implementation of the proposed NRET scheme in light of a pending national emissions scheme. Expedite clarity on transition from state-based emissions instruments to a national-scheme
8	Rule out underwriting emissions risks on project developments
9	Closely monitor national energy market reforms of key relevance to NSW
10	Restrict any future investment to reliability-specific mechanisms, not new investment in generation that participates in the NEM itself
11	Encourage and support demand-side response initiatives

Morgan Stanley's recommended options are summarised in the remainder of this section, and are discussed in more detail in Section 5.

1.5 Recommended Options for NSW Government Action (cont'd)

Recommendation 1a: To optimise private sector appetite for investment in new generation, the Government should exit the generation sector altogether by way of selling all of its existing generation assets, both existing plant and the development sites of the SOCs.

The sale to the private sector of all the Government's generation assets would address a number of preconditions to private investment, by:

- Enabling buyers of generation assets to incrementally add further baseload capacity by way of new developments to progressively grow a larger development portfolio. The development of new capacity as part of a larger diversified generation portfolio has proved an effective method of generation development in other states and markets
- Eliminating the threat of State-owned corporations investing in new generation in competition with the private sector. A wide range of private sector participants perceive that State-owned corporations are not subject to the same level of financial discipline and scrutiny as privately-owned corporations, and are therefore more likely to make noncommercial investments in generation capacity which can suppress the wholesale market price and reduce returns to other generators (including private sector investments). Irrespective of the actual level of capital discipline applying to State-owned corporations, the mere perception that they are not subject to rigorous capital discipline may be sufficient to deter the private sector from investing in competition to State-owned corporations
- Addressing private sector concerns regarding the bidding, trading and contracting behaviour of State-owned generators. While most private sector participants view State-owned generators as operating commercially in normal market conditions, there is a perception that State-owned generators may be subject to noncommercial pressures during periods of market stress e.g. intervention by government may result in State-owned corporations bidding noncommercially. We are not aware of any evidence to suggest that State-owned corporations behave other than commercially in their bidding and contracting. However, the mere perception of this risk can be sufficient to either deter private investment, or increase the risk premium that private investors require to invest, thereby increasing the overall cost of new generation investment
- Various SOCs have development sites for new generation and some of these are highly prospective. There is little to be gained by retaining such sites where the Government is seeking to optimise conditions for the private sector and eliminate stranding risk concerns
- Removes any motivations for the NSW Government to replicate market devices such as ETEF

A partial divestment (retention of some generation in government hands) would not be as effective in creating the right conditions for investment as a divestment of the whole.

Recommendation 1b: In the event that the Government decides not to adopt Recommendation 1a, the Government should transfer its economic interests in its generation fleet to the private sector by way of long-term leases.

1.5 Recommended Options for NSW Government Action (cont'd)

A transfer of economic interests in generation plant to the private sector via a lease could deliver equivalent market outcomes as Recommendation 1a, while retaining legal ownership of property and infrastructure. A similar model was used in the transfer of the South Australian generation businesses to the private sector.

Recommendation 2: The Government should sell the retail operations of Energy Australia, Integral Energy and Country Energy.

Sale of the retail operations of Energy Australia, Integral Energy and Country Energy will:

- Greatly strengthen the incentive for private parties to invest in new peaking and intermediate generation, thereby securing sufficient investment in capacity to cover future growth in peak demand
- Significantly enhance the prospects of private investment in baseload generation, as private companies with exposure to NSW retail load will have a commercial incentive to either invest in, or write contracts with, new baseload generators in order to supply emerging energy demand
- Protect the value of the State's investment in its retail operations by avoiding the likely decline of State-owned retailers over time, due to the growing market penetration of larger, integrated retailers with lower cost bases

Recent power generation investment in Australia has been significantly influenced by private sector retailers hedging their wholesale electricity risks by building and buying generation.

This behaviour has historically been concentrated primarily at the peak/intermediate end of the spectrum, but the available evidence points to this being driven by market need, not a lack of appetite for baseload generation per se.

For those parties who are retailers and whose principal generation strategy is to hedge their load, their investment appetite for new baseload in NSW will be considerably higher if they are able to acquire a material retail position. The prospects for those retailers to take a 'long baseload' position in NSW, absent a retail hedge, is remote.

While a sale of retail operations is necessary to greatly enhance the prospects of ongoing private investment in NSW generation, and if implemented alone would achieve some of the Government's objectives, it will not alone be sufficient to implement the full set of conditions required for private investment in generation.

Recommendation 3: The Government should actively monitor the progress of reforms to NSW planning, development approval and environmental licensing processes to ensure that proposals for new generation capacity, and associated fuel supplies, are considered expeditiously, cost effectively and predictably, without compromising the quality of environmental assessment.

The Government should also ensure that environmental planning approval processes are genuinely incremental, and do not unnecessarily duplicate or over-ride policy considerations which are handled by alternative regulatory or market mechanisms.

1.5 Recommended Options for NSW Government Action (cont'd)

For the private sector to be able to respond to community and government demands for timely new power supply, it must have the ability to respond to market conditions in a timely manner.

A number of parties made reference to the NSW development approval process being slower, more bureaucratic and more costly than other states. The revised 3A process is seen as a creditworthy improvement, but more needs to be done. Government will not be able to hold the private sector accountable for delays in investment if these in turn are due to cumbersome approval processes.

We recommend that the Government continue to review and make every effort to streamline the approval process for new power station sites and associated infrastructure.

In particular, the Government should ensure that the environmental assessment process is genuinely incremental, and does not unnecessarily stray into matters that are handled via other regulatory or market mechanisms. Environmental planning processes should also avoid attempting to regulate carbon emissions at the individual plant level, when alternative policy mechanisms (e.g. the Greenhouse Gas Abatement Scheme, or the proposed national emissions trading scheme) are being pursued to control aggregate sector emissions. Environmental planning authorities should not adopt a quasi-central planning role, by attempting to "second guess" the market need for a generation investment when an effective wholesale electricity market is already in place.

Recommendation 4: The Government should ensure it implements the phased removal of the Electricity Tariff Equalisation Fund (ETEF), under the timetable previously communicated to the market.

Different parties regard ETEF differently. Without wanting to debate the history and risk management reasons for the introduction of the mechanism, it is an example of government devices that have intervened in the market. In the case of ETEF, it provides an automatic hedge for the retail SOCs for part of their NEM exposure, provided by the generator SOCs. The consequences of ETEF might include reduced contract liquidity (since the SOCs have contract cover essentially provided by ETEF) and may, in conjunction with a lack of private exposure to retail customers, defer the construction of peaking generation (since the retail SOCs have peak risk partially covered by ETEF).

A pathway for the progressive removal of ETEF has been set and this should not change.

1.5 Recommended Options for NSW Government Action (cont'd)

Recommendation 5: The Government should support the planned review of the effectiveness of retail competition by the Australian Energy Market Commission in 2010, and consider the removal of regulated retail price caps at that time, should the review find effective competition in the NSW retail market.

If tariffs are not removed Government should ensure they are cost reflective and market responsive, with a positive bias towards providing appropriate margins to facilitate competition, new entrants and new investment. Any social policy objectives should be set by means other than by distorting price mechanisms, and any market power issues should be dealt with by mechanisms other than distorting price.

Further, the NSW Government should not support any moves to reduce the level of VOLL (the maximum wholesale price) from its current level, or otherwise seek to regulate or influence wholesale market prices. Reducing the level of VOLL may impact on private sector appetite for new investment, particularly in peak generation.

Where overseas markets have failed to bring about new investment, electricity price caps have at times been identified as one of the contributory causes (refer Section 4.8).

The reason for this is not hard to determine—if a regulator sets a cap at a low level, this caps the overall revenue for the sector at a low level. When generation becomes scarce, and prices should rise in response, a price cap may depress scarcity values, increasing the risk that signals for new generation will not be recognised and responded to in a timely manner. An artificially low price cap sends a signal to market participants that new investment is not valued.

Price caps are doubly dangerous in electricity for the following reasons:

- For the cap to have any impact, it must occasionally limit the price that would otherwise be charged on purely commercial grounds. Otherwise there would be no purpose in a cap. Proponents of caps must recognise that if and when this limitation occurs, it may be at exactly the point in time when wholesale prices are increasing as a genuine signal that new investment is required
- Price cap setting mechanisms cannot respond as quickly to market events as would an unrestrained situation. The process of arguing for and against a change in the price level, and the regulators' deliberations on this issue, necessarily take some time and if caps are inappropriately set, will add to the development timeframe for new generation plant
- A price cap that sets an artificially low price level does nothing to provide signals to end-users to curb their consumption, and in fact encourages excessive consumption and demand growth, since the price is artificially cheap. This may exacerbate a growing shortage of generation that would otherwise occur more slowly
- Price caps may be applied in order to try to reduce the cost of any anti-competitive behaviour. However we note that price caps may deter investment, and investment by new entrants, and as such may simply entrench the market position of incumbent firms
- Price caps can threaten the credit worthiness of retailers when wholesale prices are high, which can then have wider ramifications for contract counter parties

1.5 Recommended Options for NSW Government Action (cont'd)

There are clear and obvious risks to timely investment in new generation capacity when prices are capped at inappropriate levels, simultaneously encouraging consumption and deterring investment. An inappropriate price cap is not consistent with putting a high value on reliability in times of market disruptions or shortages.

In our view regular retail price reviews by regulators do nothing to enhance long-term decision-making in electricity markets, and may be contributing to short-term decision-making. There is no incentive for retailers in particular to enter into long-term wholesale supply contracts beyond the next retail tariff review date, since the costs embedded in that contract may not be carried through in any regulatory review. It has been noted in several submissions that the electricity market tends to short-term contracting, and that excessive short-term behaviour could jeopardise new investment.

In short, the 'law of unintended consequences' has particular application to price distortions in electricity markets and the potential unintended consequences are many. The deterrence of new investment is not the only consequence of a price cap, but it is the most critical and obvious risk.

Recommendation 6: The Government should encourage the Commonwealth to progress the design and implementation of a national emissions trading scheme as a high priority, in order for the market to have sufficient confidence of likely carbon pricing implications for investments in new generation capacity.

In particular Government should encourage the Commonwealth to release key parameters for the scheme as soon as possible to facilitate investment certainty, even if such key parameters are released ahead of the release of the full detail of the scheme.

Based on recent policy announcements by the two major political parties, the market is now factoring in a carbon trading scheme to be implemented between 2010 and 2012.

The fact that the market is expecting a carbon trading scheme to be implemented should not be taken to indicate that market participants have any real clarity on how to invest under such a scheme. The market now has (effective) certainty of a scheme, but uncertainty as to how it will operate in practice. The actual key economic and commercial parameters for the scheme are unknown, these include:

- Medium-term emissions targets (say to 2020), which will allow modelling of reasonable scenarios as to how this could be met and at what cost
- Which different industries (e.g. trade exposed) are included in or excluded from the target, which will influence supply and demand
- Transition rules from existing schemes to a new national scheme
- The penalty for non-compliance, as this will influence cost
- The 'red line' in time for when new investment will be grandfathered into the scheme as 'pre-existing' investment, and so be issued with free permits, and when it will not

As the actual parameters of the future scheme remain unknown, it is unrealistic to expect that the private sector can currently differentiate between investment decisions that are at or near the margin, or could swing either way based on different technology or fuel choice (e.g. coal or gas).

1.5 Recommended Options for NSW Government Action (cont'd)

As noted elsewhere in this report, private investors (and markets in general) cannot hedge against regulatory and policy risks, with delayed investment decisions (i.e. not committing cash in the face of uncertainty) being the only logical response.

In consequence, there is a risk that the private sector will not invest in the face of considerable emissions policy uncertainty, with investment delays meaning that prices rise above the new entrant level, such that new investment only occurs when the private sector has sufficient return headroom to absorb the emissions uncertainty with a project that is economic even if penalised more than expected. It should be self-evident that this policy uncertainty ultimately will come at a higher cost to the community (in terms of price and reliability) than would otherwise occur in an environment of clear policy with the parameters known years ahead of implementation.

Hesitancy in investment in the full range of new power generation options exists today. This will become critical to outcomes in the NEM over the next three to four years depending on the overall demand growth that occurs in the future in the NEM. We noted and concur with the comments of the Australian Business Council for Sustainable Energy *"It is important that the level of the target for future emissions is articulated sooner rather than later so that new investment in generation capacity can be planned."* (1)

At present the private sector appears reasonably comfortable building gas-fired plants. While a gas-fired plant adds to emissions, modern CCGT has a lower intensity than the average for the NEM. CCGT may or may not be the least cost baseload power for the NEM, but at present the private sector (to our knowledge) is not contemplating building coal, so gas-fired technology is the only option.

This relative comfort with gas technology may also reflect that peak and intermediate prices will be less affected by carbon price issues given (i) more lower-intensity gas and hydro dispatch will tend to occur at peak periods and (ii) carbon price factors will be a relatively smaller proportion of total peak and intermediate electricity prices and a larger proportion of lower off-peak prices (when baseload coal can be expected to be the dominant plant). It should be noted that carbon price expectations will impact forward electricity price expectations, and a lack of clarity on carbon settings may impact forward electricity prices and trading behaviour.

As the fuel mix in each state is different, and electricity prices will reflect carbon settings, the emissions regime will also impact on flows on the transmission lines inter-state and intrastate. At all levels, we expect the electricity market and its supporting infrastructure to function more effectively and efficiently the earlier clarity is provided on the emissions regime settings.

The lack of emissions certainty is a key potential 'frustrating condition' to new investment in power generation, and at present there is a complete lack of appetite to invest in new coal fired power given the high level of uncertainty. As at time of writing, this policy uncertainty risks compromising the efficiency and reliability of the NEM over the next 5–10 years, as delayed investment decisions will take time to "catch up." NSW electricity consumers would be best served by competition between gas, coal and other technology and fuel alternatives, in a regime where emission factors have been dealt

Notes

1. Australian Financial Review, 18 July 2007

1.5 Recommended Options for NSW Government Action (cont'd)

with via a single, transparent and uniformly applied national mechanism. At present the NEM remains a considerable distance from this ideal.

Recommendation 7: In the event a national emissions trading scheme is introduced, the Government should review the continued need for and implementation of state-based, technology-specific incentive schemes also aimed at reducing greenhouse gas emissions (e.g. the proposed NSW Renewable Energy Target).

Additionally, in the event of release of a national emissions scheme, the Government should work with the Commonwealth to rapidly issue clear rules on transitional mechanisms from existing schemes (e.g. GGAS) to the national schemes. The necessary consultation process to finalise these rules could be brought forward via the issue of discussion papers or similar processes.

Market participants have generally stated strong preferences for a single national emissions scheme, and for government to set the overall rules for emissions and let the private sector work out the optimum (most economic) way to deliver new investment.

In turn, if an overall national scheme has been instituted in order to target overall carbon emissions levels, most participants do not see a place for technology or fuel-specific policy settings, as these then confuse or distort the achievement of the overall emissions level and the role of any single national scheme. Some parties argue that subsidies are required to commercialise technology which otherwise would not get the opportunity to mature. If so, it would be better that commercialisation schemes are done on a level playing field nationally rather than on a state by state basis.

From our perspective, the key seems to be targeting the appropriate overall level of emissions, and then delivering on the target. How we get there is less important provided it is done so as efficiently as possible, with the least cost to the community. Consumers would appear to benefit most if there is unrestricted fuel-on-fuel, and technology-on-technology competition, with the least cost combination (with carbon settings factored in) winning out.

Recommendation 8: The Government should not provide any carbon-related concessions or guarantees to specific new generation projects, unless as a "last resort" step where it can be demonstrated that security of supply will be compromised because the market fails to invest in new generation capacity due to uncertainty regarding emissions trading.

It will be clear to all readers of this report that Morgan Stanley believes that emissions uncertainty is currently affecting investment decision-making, and will continue to do so in the future unless and until this uncertainty is removed.

However we also believe that:

- Markets will be able to quickly assess the impacts of the scheme once its key parameters are known
- Provided that these parameters are made clear during 2008, or 2009 at the outside, generation investment and system reliability are unlikely to be adversely affected. This does not mean that the absolute least cost configuration of power generation projects will be developed in the interim. That is, efficiency of the market may be less than would otherwise occur

1.5 Recommended Options for NSW Government Action (cont'd)

We do not believe the Government should take the step of underwriting emissions risk to facilitate investment in new baseload plants, and in fact should rule out taking this step for any new generation for the following key reasons:

- The possibility of project-by-project exemptions on future projects risks shifting the 'level playing field' that current prospective investors would otherwise expect
- This uncertainty risks delaying investment plans further, since prospective investors won't know if competing plants might receive a significant cost advantage, risking creating a self-fulfilling forecast of investment shortfalls due to emissions risk
- Exemptions will affect subsequent market outcomes for many years
- Underwriting emissions risk may well be more costly to NSW taxpayers than the alternative of less investment, or gas only-investment, and potentially (not certainly) higher interim prices
- Underwriting emissions risk may further jeopardise retention of the State's AAA rating

Recommendation 9: The Government should continue to closely monitor market developments and the progress of ongoing reform in the following areas which impact on electricity market performance and are of particular relevance to NSW as a net importer of gas and electricity:

- **Gas transmission development and frameworks for national gas market rules**
- **Electricity transmission augmentation and interconnection**
- **Electricity market contracting liquidity and availability**

At all times we would encourage Government to work with MCE processes and adopt national rather than state-based approaches to market development.

In our work a range of parties raised issues which go to the operation of an efficient and reliable electricity market. Most of these issues go to market operation and rules. As such they are outside the direct control of the Government in an environment where national approaches are preferred to state government intervention. However, as NSW is the largest electricity market in Australia and houses the largest population of any state, its status as a net energy importer make transmission and market development issues particularly critical for Government. These key areas were:

- Access to gas supply, adequacy of gas reserves and transmission to support large scale expansion of gas-fired power generation, and reliability of gas supplies. Many parties referenced the 22 June 2007 gas supply disruptions in NSW and their ability (or lack thereof) to be assured of firm supply at times of high demand due to the current gas market structures and conventions
- Electricity transmission planning and augmentation and whether this process could be integrated more closely with generation development. Locational signals and the firmness of trading across regional boundaries were also mentioned as areas that could be improved
- Contracting behaviour was noted as being relatively short-term (typically two to three years) as against long-term investment decisions for both new generation capacity (20–40 years) and investment decisions for major industrial users (similar time frames). There are likely to be multiple

1.5 Recommended Options for NSW Government Action (cont'd)

causal factors for short-term contracting behaviour. While contracting between parties is not completely transparent, Government should monitor outcomes and investigate more fully if contracting behaviour becomes problematic for decision-making for large scale investment in electricity or by end-users

Recommendation 10: Should the Government be concerned about the ability of the market to provide sufficient capacity to reliably service demand, it should not create new competitive investment in the NEM but rather implement a reserve capacity approach that does not distort wholesale electricity market outcomes and investment incentives.

Under no circumstances would we recommend fixed obligations compelling specific generation investment by private sector buyers of assets acquired in any sale process.

Based on our review, we believe the best approach to secure reliability is to give the market the highest confidence in future investment returns by avoiding Government involvement and intervention in the sector altogether.

Based on our extensive review of the NEM and offshore markets, we believe that:

- The current design of the NEM works to bring on new investment, despite many and varied imperfections in the market, and should be given a fair opportunity, free of Government intervention, to demonstrate that it can bring on new baseload investment in NSW
- The biggest single risk to new private sector investment is government intervention, whether explicit (new rule setting) or by omission (flagging new regimes for emissions but providing insufficient clarity on how these will function). Commodity and financial markets hedge many risks, or otherwise value them and deal to them efficiently, but regulatory and political risks cannot be hedged or accurately predicted. Government intervention in a market, no matter how well intentioned is subject to the law of unintended consequences, and in electricity markets, unintended consequences can be many, varied, and potentially disastrous. Investment and reliability is much more likely to occur smoothly where Government protects and champions a market structure rather than seeks to deal directly in it

Reliability in the NEM does not occur by accident and the market has been designed to ensure a 99.998% reliability standard (refer to Section 3). Various devices could be implemented to achieve even higher reliability levels, none of these are costless and each would result in higher overall electricity prices if they were implemented. These types of devices have been discussed most recently in the recent report by the AEMC Reliability Panel in its Comprehensive Reliability Review, Interim Report, March 2007. It should be noted that the Government would not be able to unilaterally implement several of these devices.

Morgan Stanley believes that were the Government to seek to impose development obligations on buyers of assets in a sale process, or "use it or lose it" rights on development sites, this:

- Would come at a significant cost, since developments are unlikely to be at a stage where risks can be fully priced and efficiently contracted away. The private sector would only take these risks if it received a material value transfer from Government

1.5 Recommended Options for NSW Government Action (cont'd)

- Is simply not commercially feasible to impose such obligations to build large plants (with high capital cost) or for coal-fired plant in the current environment
- Would only displace competing commercially-driven investment and not add to it, therefore not actually adding to reliability over the medium and long-term
- Is not recommended under any circumstances

Recommendation 11: The Government should encourage and support demand side response (DSR) initiatives wherever possible, whether through market reforms, regulatory settings, third-party access rules or technology initiatives like advanced metering rollout.

The NEM is a supply-side only market, and the demand side of the market only participates to a limited degree. Numerous academic papers on market design issues in international electricity markets revolve around the difficult issue of how to best design electricity markets where demand is essentially insensitive to price response. Without clear market-based signals as to how demand values supply at times of scarcity, markets invariably refer to regulated concepts such as VOLL price caps. This is not an esoteric issue—users demand reliability from electricity markets, yet the price of reliability is not transparent or even clearly observable, with a proxy price (like VOLL) set by regulation.

DSR is not a panacea to a fundamental lack of investment and studies that we are aware of have tended to show that DSR does not reduce overall consumption materially, but rather shifts consumption from peak into off-peak periods. Invariably DSR requires not only market/tariff signals, but also behavioural change, which will no doubt be slow. However greater DSR could potentially play an important role in:

- Shaving peak demand at times of market stress
- Potentially mitigating the amount of peak generation investment that may only be required for a few days each year; reducing wholesale energy costs
- Potentially mitigating the amount of network (poles and wires) investment that may only be required for a few days each year; reducing cost through lower regulated tariffs
- Providing a price signal to the supply side, and progressively increasing the elasticity of demand to electricity price, hence improving the functioning of the NEM over time

1.6 Risks

1.6.1 Risks of No Action

If the Government does not act to reform the current electricity industry structure then:

- It will have no choice but to pursue new investment in generation, not only baseload generation but likely also peak and intermediate generation. In the absence of change there is no reason to expect that the Government would not repeat the experience where the Government felt it needed to proceed with the Colongra plant to ensure new investment. In the absence of genuine reform in NSW the private sector is likely to look elsewhere for investment opportunities
- It will have to choose between competing generation projects proposed by competing generator and retail SOCs. Under private ownership multiple projects might proceed as private sector participants seek to compete with each other. However funding multiple competing projects seems an irrational outcome under the current industry sector where the Government is the same and sole shareholder of the six retail and generation SOCs, and endorsing competing projects that each lowered the returns of the other would be a waste of taxpayers money. In such an environment of Government selected projects and fiscal restraint, less generation development might actually occur under Government ownership than would be experienced in private ownership
- It will allocate capital to competitive generation projects which will reduce the capital available for other social programs and investment, in the absence of further borrowings. We understand that additional borrowings for generation investment may place additional pressure on the State's AAA credit rating
- The values of the retail businesses in their current form will continue to slowly erode over time under FRC. Substantial investment is required to place these businesses on an equal competitive position with the private sector
- It will continue to bear all the emissions risk in the electricity sector as it does now. While this may affect returns from ongoing trading, it may also multiply the amount of capital required for investment
- It may be compelled to invest substantial capital to improve the emissions footprint of its generation fleet over time, in addition to normal ongoing stay in business capital expenditure. This may have a compounding effect on the State funding in the electricity sector. Emissions-related development (such as pilot tests for carbon capture) may reduce the net sent out energy of the existing plant, as the capture process necessarily consumes some energy. The loss of energy from the existing plant may then require further capital expenditure on additional plant to compensate
- The consequences of the Government's decision on the way forward clearly go well beyond just consequences for new investment. If Government wants to continue operating competitive retailing and generation businesses in the National Electricity Market, then it needs to invest considerable sums in ensuring these businesses are able to compete on a level playing field with the private sector, which has direct access to capital. Retaining the existing government owned retail and generation businesses, and not investing in them, can not be sustained.

1.6 Risks (cont'd)

1.6.2 Ongoing Risks to Investment

If the Government accepts our recommendations and reforms the sector, risks to timely new investment are minimised but can never be completely eliminated (and in any event are not zero under Government ownership). In our view a lack of timely new investment is less likely to be caused by one isolated event or single issue (with the possible exception of emissions uncertainty), but would be more likely if there is a confluence of several risks over a period acting in combination. These might include the following risk factors, some of which are being experienced at the present time:

- Ongoing emissions uncertainty. It should be clear from this Report that Morgan Stanley views emissions uncertainty as a significant risk to timely investment in new power generation by the private sector, especially coal. As this is essentially a Commonwealth issue, the Government cannot remove this risk without committing NSW taxpayers' money to underwriting outcomes (which we do not recommend and which would further pressure the AAA rating of the State)
- Escalating fuel prices, in particular gas but not only gas, for those parties that do not have access to contracted or significant internalised fuel reserves
- Escalating construction costs
- Delays in obtaining site approvals
- Extended procurement timetables for new equipment from manufacturers
- Retail price caps. The continuance of caps on the extent to which cost pressures (such as fuel and existence costs) can be passed through to consumers. We note that the introduction of an emissions regime necessarily has to increase electricity prices in order to have any impact on consumption behaviour

If several or all of the factors listed above were to act together in combination at once, it is not difficult to imagine delayed investment by the private sector. There would be little or no appetite to invest where the private sector did not have confidence that its costs would not be able to be recovered. We note that if government-owned enterprises are acting on a commercial basis on a par with the private sector, they should also have exactly the same aversion to new investment in these circumstances.

Conversely, if retail prices were uncapped and permitted sites were available, then we would expect private sector investment would occur as desired even in the face of escalating input costs. The electricity sector is multifaceted and many factors ultimately play on investment decisions.

Readers will note that of the six main risk factors we have identified, three (emissions uncertainty, development approval and retail price caps) relate to government policy settings or processes and are not, strictly speaking, market-driven issues. In our terminology, these policy and process issues are all potential 'frustrating conditions' to new investment. Government can de-risk timely new private investment by eliminating these risks or reduce them to the lowest possible levels.

Private Sector Investment: Babcock & Brown Braemar Power Station in Queensland
Photo Courtesy Babcock & Brown Power

Braemar Power Station is a newly constructed 455MW OCGT generator, commissioned in late 2006, located in southern Queensland, 35km south-west of Dalby. Braemar's location is close to competing gas supply sources, being adjacent to the Queensland coal seam gas fields and gas pipelines. Braemar was built to service long-term electricity hedge contracts with the then Energex electricity retail business owned by the Queensland Government.

Section 2
Approach to Assignment

2.1 Introduction

Morgan Stanley Australia Limited ("Morgan Stanley") was appointed as adviser to the Owen Inquiry in late May 2007.

Morgan Stanley's scope of work was to provide advice to the Owen Inquiry pursuant to its fourth term of reference as to:

- The conditions required for private sector investment in new generation in NSW
- Identify the options available to bring about these conditions for investment

Our advice to the Owen Inquiry is contained in this report.

2.2 Work Program

Our work program incorporated research, analysis of public and confidential submissions to the Owen Inquiry and discussions with market participants to determine the conditions for private sector investment in new generation in NSW.

The list of parties consulted during this work is set out below in Table 3. Our focus was discussions with those parties most likely to invest, and/or enter into long-term contracts and so this list is a subset of the full list of parties that made submissions to the Owen Inquiry across all four terms of reference.

Table 3: List of Parties Consulted by Morgan Stanley

AGL Energy	Energy Australia	OneSteel
Alinta Limited	Energy Response	Origin Energy
APT Group	Eraring Energy	Santos
Babcock & Brown Power	Integral Energy	Standard & Poors
Bluescope Steel	Intergen	Transfield
Centennial Coal	International Power	TRUenergy
Country Energy	Macquarie Generation	Visy
Delta Electricity	Major Energy Users	

2.3 Assumptions

Morgan Stanley has made a number of simplifying assumptions in carrying out its work, in order to set the framework for the market structure and the investment conditions and options. These assumptions are set out in Table 4 below. While these are assumptions, the continuation of these factors is important for private sector investment as set out in this report.

Table 4: Morgan Stanley Assumptions

Assumption	Description
No Change in Fundamental Market Structures	No change from the compulsory gross pool, energy-only market structure with a VOLL cap set at $10,000/MWhr
No Change to FRC	Full retail contestability continues in force in NSW
ETEF Windback Continues	No change to the progressive scaling back of the ETEF risk management mechanism between the SOC retailers and generators
No Change in Reliability Standard or Mechanisms	No change to the existing targets for reliability and mechanisms supporting reliability

2.4 Research and Evidence from International Markets

Morgan Stanley has reviewed numerous academic economic papers on the function and design of offshore electricity markets, to draw on experiences of other markets in determining our recommendations for investment conditions in the NSW market.

However we caution that almost every offshore market has its own unique mix of market design, regulatory institutions, fuel and technology types, transmission interconnections (or not) and different composition of private and public firms operating in the market. Each of these differences can in turn cause differences in how markets operate.

Accordingly, while some of the evidence from offshore markets is useful and insightful, it has to be interpreted with caution and should not be relied upon as complete predictors of how the Australian NEM might react in circumstances that appear superficially similar. Factors that appear to affect investment in one setting may not appear to affect investment in another. Academic studies produced by different authors emphasise different and sometimes conflicting factors in assessing how markets have performed. Studies are current at the point in time at which they were produced, often after a period of stress, and these conditions may now have changed.

The process of electricity industry reform in Australia is relatively advanced in a global context. There is not an extensive pool of other comparable markets which have been liberalised for a significantly longer period than our own market, which would allow for easy observation and firm conclusion.

2.5 About Morgan Stanley

Morgan Stanley is a global financial services firm and a market leader in investment banking, securities, investment management and wealth management services—with more than 55,000 employees in over 600 offices around the world. Since 1935, Morgan Stanley has adhered to the highest standards of integrity, excellence and client focus as well as demonstrated a long-term commitment to the development of our businesses and financial markets worldwide. Building on these foundations, the Firm's objective is to be the "first choice" financial services firm for governments, corporations, and both institutional and individual clients. Morgan Stanley Australia has conducted business for over 50 years, and has provided advice on over A$100Bn of investment banking assignments.

This report has benefited from the international reach of Morgan Stanley and the experiences of personnel with experience across Asia, U.S., U.K. and European energy, power, commodity and emissions markets.

This assignment has been carried out by a team of Morgan Stanley executives with considerable experience in advisory and corporate finance assignments in the power and utilities sector in Australia, collectively totalling several decades of corporate advisory experience.

Except where noted to the contrary, the views and opinions expressed in this report are those of Morgan Stanley alone. This Report should be considered as a whole and, parts of the discussion and analysis should not be considered with consideration of the remainder of the Report.

Morgan Stanley received a fixed fee for the preparation of this report. These fees are not linked to or contingent in any way on the outcome of any transaction that may or may not be carried out by the Government subsequent to this report.

This Report was prepared solely for the purposes of the Owen Inquiry and the discussion and analysis contained herein should not be relied upon or used in any other manner or context. Readers should refer to the disclaimer inside the front cover.

Private Sector Investment: Intergen's Millmerran Power Station in Queensland
Photo Courtesy Intergen Australia

InterGen (Australia) Pty Ltd's 880MW Millmerran Power Station is sited near the town of Millmerran on the Darling Downs in southern Queensland, and commenced operation in 2003. Millmerran uses supercritical steam cycle technology which requires about 10% less fuel than an equivalent conventional unit. This technology saves coal and reduces carbon dioxide (CO_2) emissions by 400,000 tonnes per year when compared to conventional coal-fired power stations. The power station combines engineering technology and effective water conservation techniques to reduce daily water consumption by 90% compared to conventional coal fired-power projects. Millmerran Power won the Banksia Environmental Award in 2006 in the water category for outstanding achievement and national leadership in protecting or enhancing Australia's water resources.

Section 3
NEM Market Design, History and Performance

3.1 Introduction and Scope

Many parties have provided comments in submissions to the Owen Inquiry on issues which go to market design of the NEM and potential alternatives that could be considered. We readily acknowledge that market design is a fundamental issue as it frames commercial incentives, regulations and outcomes.

However, it is not our intention to provide a complete analysis on the structure and history of the NEM and the issues that arise compared to alternative market designs. For our purposes, the NEM is what it is, and Morgan Stanley has assumed that the fundamental structure of the NEM and its reliability targets and settings remain unchanged in the foreseeable future. Morgan Stanley's client is the NSW Government, and even if the NSW Government wanted to change the NEM, it is not within its power to do so unilaterally.

Proposals to make significant changes to market design would almost certainly defer new generation investment in NSW, as market participants would need to assess the economics of investment under new market models. As such we do not believe fundamental change to the market model (however well intentioned) would be a positive for short-term investment decision-making. While we have considered all comments in the various submissions, this report does not debate issues of market design, except as they go to the conditions for private investment in the NEM, which is discussed in Section 4.

The NEM (and all electricity markets) are complex and this report necessarily assumes that readers have some level of existing understanding of its function, and background understanding of associated markets like gas. To completely describe all of the workings of the NEM and related factors would double the size of this report and is not within our scope of work. In preparing this report, we have attempted to explain concepts as simply as possible. Readers who are interested in learning more about the NEM and electricity market design issues should refer to the Owen Inquiry Report and the references and further reading sections in the appendices to this report.

In this Section 3 of this report we:

- Provide a short outline of the development of the NEM
- Provide a quick overview of its workings for those readers who are less familiar with the operation of the NEM
- Seek to outline how the existing design of the NEM already proactively attempts to achieve security and reliability goals
- Assess investment performance in the market to date, causes of interruption, and how the NEM has performed against its reliability targets

We have attempted to draw attention to the positive aspects of market design for new investment and also highlight negative aspects, though these are mainly covered in the topics discussed in Section 4.

3.2 Development of the NEM

The NEM began operating as a wholesale market for the supply of electricity in Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia in December 1998 with

3.2 Development of the NEM (cont'd)

precursor markets operating between NSW, Victoria and the ACT prior to that time. In 2005 Tasmania joined the NEM as a sixth region, with operational effect from April 2006.

Prior to the creation of the NEM, the east coast electricity supply industry was characterised by:

- Vertically-integrated State government-owned generation and transmission monopolies
- Regionally-based distribution business, responsible for both distribution system operations and maintenance and retail electricity supply
- Centralised, coordinated planning of generation and transmission system development
- Prices at all levels of the electricity supply chain were set via regulation, i.e., there was no market to generate price signals for new capacity investment

Partly in response to security-of-supply issues in the late 1970s/early 1980s, and partly anticipating "state development" projects, State electricity authorities had invested heavily in generation capacity over the pre-NEM period (particularly during the 1980s).

This large investment program resulted in significant surplus capacity, as evidenced by the high reserve margins set out in Table 5 below.

Table 5: Reserve Plant Margin ("RPM") by State, 1986–1987 to 1989–1990 (%)

	State				
Year	NSW	Vic	Qld	SA	WA
1986–1987	73	50	47	62	46
1987–1988	70	46	53	50	42
1988–1989	69	38	47	38	24
1989–1990	46	27	37	45	25

Source Industry Commission, Energy Generation and Distribution, Report No. 11, 1991

A degree of reserve margin is typical of electricity supply systems, and clearly is both required and prudent for risk management purposes. As electricity consumers place a high value on reliability of supply, investment in reserve capacity is a necessary contingency against unforeseen "spikes" in demand, and/or unplanned unit outages.

However, the then Industry Commission (a predecessor organisation to the current Productivity Commission) considered the above reserve margins excessive, compared to its view of an "optimal" reserve margin of 20% (we note this is broadly consistent with 15%–25% reserve margins typically seen as appropriate in international markets). While the pricing arrangements applying pre-NEM may not have made the costs of excess margins transparent, surplus capacity comes at a cost in that the capital that funded the surplus reserve capacity has an opportunity cost (i.e., it could have been diverted to other more valuable uses). In the case of Government funded capacity, this capital has been drawn from taxpayers or borrowed against future tax revenue.

Using an 8% real rate of return as the opportunity cost of capital, the Industry Commission estimated the opportunity cost of capital of excess generation capacity across Australia as set out in Table 6 below.

3.2 Development of the NEM (cont'd)

Table 6: Estimated Cost of Excess Capacity

	NSW	Vic	Qld	SA	WA
Reserve Plant Margin 1989–1990 (%)	46	27	37	45	25
Assumed Best Practice (%)	20	20	20	20	20
Excess Capital Stock (%) (1)	18	5	12	17	4
Capital Annual User Charge (8% Real Return) ($MM) 1989–1990	2,487	1,978	1,272	452	440
Cost of Excess Reserve Plant Margins ($MM)	443	109	158	78	18

Source Industry Commission, Energy Generation and Distribution, Report No. 11, 1991

Notes
1. Calculated as: 100x (Existing RPM—Optimal RPM)/(100 + Existing RPM)

The Industry Commission estimated that the surplus generation capacity in New South Wales alone in 1989–1990 had an *annual* opportunity cost of $443MM.

This implies that in 1989–1990:

- NSW electricity consumers paid $443MM more in electricity charges than they would have paid, had the excess capacity not been built (assuming that electricity prices were set to recover the cost of excess capacity); or
- The NSW Government would have had an additional $443MM of annual spending capacity, had the excess generation capacity not been built (assuming that electricity prices did not recover the cost of excess capacity); or
- The opportunity cost of excess capital investment were shared between electricity consumers and the NSW taxpayers that had directly or indirectly funded its creation

The NSW fiscal position was weaker in the 1980s and 1990s than it is today, and yet the evidence shows that the State was at the same time investing in increasing an existing surplus of nonproductive generation capacity. In the mid 1990's NSW was recovering from a recession and faced large deficits, high debt levels and heavy subsidies to public trading enterprises.

It should be noted that the surplus capacity in 1989–1990 was significantly below that of a few years earlier (73% reserve margin in 1986–1987) due to the de-commissioning of old generation plants in 1989–1990. Consequently, the opportunity cost of excess generation would have been higher in the mid-1980s compared to 1989–1990.

This over-investment in generation capacity was possible because there was no wholesale electricity market in place to generate price signals for new capacity investment, retail prices were not set with reference to "efficient" costs of supply (so the costs of surplus capacity were able to be passed through to consumers) and State governments were prepared to support electricity generation investment without commercial rate-of-return requirements.

In short, the NEM was brought into being because the pre-NEM electricity market arrangements were reviewed and found to be lacking. This move to "liberalised," market-based systems for electricity supply was not restricted to Australia. Many countries had similar disappointing experiences with the shortcomings of centrally-planned highly regulated electricity and moved to liberalise and deregulate their electricity markets during the 1990's.

3.2 Development of the NEM (cont'd)

The NEM is a wholesale market for electricity. Only a fraction of the total end price paid by domestic and business consumers is accounted for by wholesale electricity costs. In a recent publication by the AER, this wholesale fraction was estimated at 41% in Victoria and 35% in South Australia. [1] Additional components of total retail costs include transmission and distribution network usage (regulated), market charges from NEMMCO, the retailer's costs and profit margins (now set competitively under Full Retail Contestability ("FRC") now being fully implemented in most NEM regions, but also subjected to regulatory caps in each state) and the GST.

3.3 Regulatory Settings in the NEM

The institutional frameworks for the NEM are a series of interwoven laws, rules and bodies. Those with national application, highlighting those most relevant to this report, can be briefly described as follows:

- The National Electricity Law, which all participating jurisdictions have enacted as statute
- The National Electricity Rules, which govern the operations of the NEM. The Rules may be changed from time to time under a formalised rule change process and are given force of law by the National Electricity Law
- The Australian Energy Markets Commission ("AEMC"), which was established to oversee the Rules and provide policy advice covering the NEM. The AEMC will progressively also oversee market development and rule making in gas markets
- The National Electricity Market Management Company ("NEMMCO") which was established in 1996 to operate and manage the wholesale power market and system security
- The Australian Energy Regulator ("AER"), which is part of the ACCC. Amongst other things the AER enforces the Law and the Rules, and acts as economic regulator to electricity and gas transmission and in the future will regulate other forms of infrastructure (e.g. distribution). Regulation of retail pricing may ultimately be transferred to the AER from the various states, pending a review of competitiveness in electricity markets
- The Reliability Panel, established by the AEMC, which has as its primary role to
  - Monitor, report and review the safety, security and reliability of the national electricity system
  - Provide advice on the safety, security and reliability of the national electricity system

The Independent Pricing and Regulatory Tribunal ("IPART") is an independent NSW body and amongst other functions also currently regulates electricity retail tariff pricing in NSW. Other states also currently maintain state-specific regulatory bodies. At present retail price regulation remains under the control of the Government. It may in the future transfer to the AER but this is a future decision for Government.

Notes

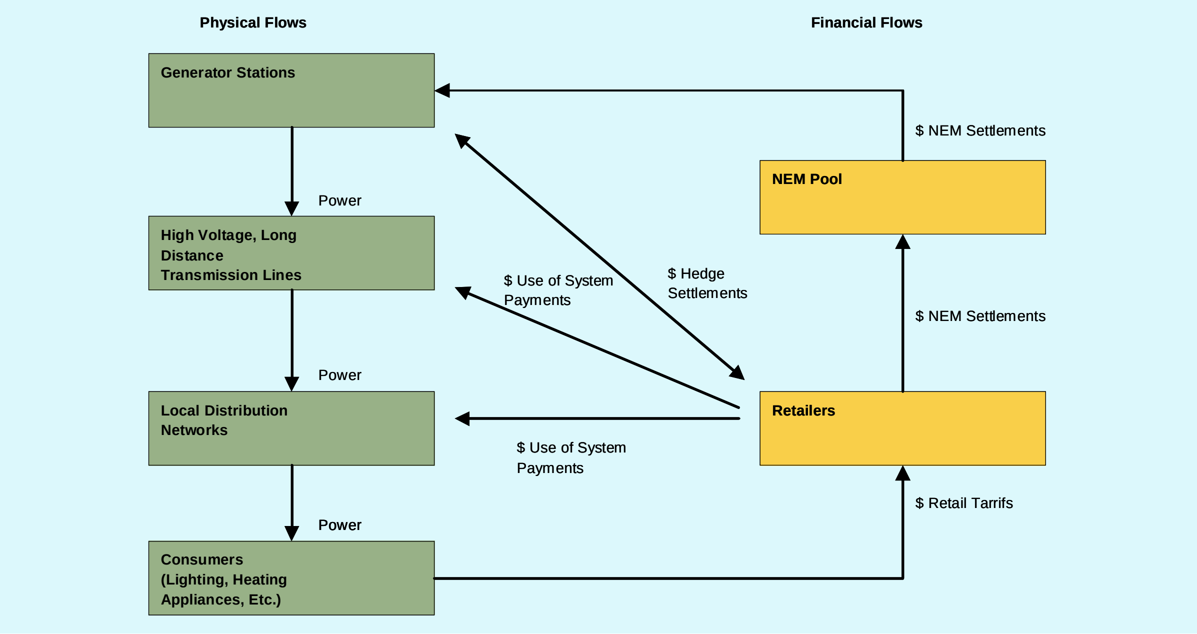
1. Source: AER, State of the Energy Market, July 2007

3.4 Workings of the NEM

Electricity has unique characteristics which govern the principles of market design in electricity markets, and make it well suited to be traded using centralised and highly formalised pool arrangements. Electricity cannot be efficiently stored for future use in large volumes, so supply has to respond to changing demand in order to keep the system in balance. Additionally, while output and consumption can be measured and metered at appropriate points in the system, it is not possible to determine which generator produced which electricity in the system as a whole.

Physical and financial flows in the NEM can be thought of conceptually as outlined in Exhibit 1 below.

Exhibit 1: Conceptual NEM Supply



The NEM electricity pool is a set of procedures and processes that NEMMCO manages, and is often described as a "gross pool" in that it dispatches and trades all power from scheduled generators as opposed to "net pool" models which dispatch surplus power only.

Wholesale trading in the pool is conducted as a real-time spot market where supply and demand are instantaneously matched through a centrally-coordinated market process. Demand is monitored continuously by NEMMCO. Generators bid to supply the market with specific amounts of electricity at offer prices. Offers are submitted for every five minutes of every day. From all offers submitted, NEMMCO's systems determine the generators required to produce electricity based on the principle of meeting prevailing demand in the most cost-efficient way. It should be noted that in the NEM, cost-efficiency is determined by the offer prices specified by generators in their dispatch bids, not by the underlying LRMC of the generators in a "merit order" concept. While short-term offer prices may reflect LRMC economics, they may (and frequently will) not. NEMMCO dispatches the least-cost generators into production so that dispatch occurs in a 'rising stack' of price from lowest to highest.

3.4 Workings of the NEM (cont'd)

As the NEM is a compulsory energy-only gross pool structure, there are some key characteristics of the market which differ from some other electricity markets:

- Generators have to be dispatched by NEMMCO in order to generate revenue from the pool. Unlike some other markets there is no capacity payment mechanism which remunerates generators for availability alone regardless of dispatch. Generators that are dispatched will gain pool revenue, those who are not dispatched (or are unable to dispatch, for example, because they are out of service) face the full opportunity cost of not being dispatched
- There is no restriction, limitation or compulsory contracting between counterparties in the NEM. While all scheduled generators are dispatched via the NEM gross pool, the pool price does not represent the true energy costs for retailers (or revenue for generators) as these parties will typically enter into swaps, options and other derivatives that significantly determine overall weighted electricity costs (or revenues) for an electricity retailer across a period. Retailers are exposed to spot pool price variations to the extent they are unhedged
- There is no direct or absolute pass through of wholesale electricity costs granted by regulators of retail tariffs caps. Actual costs experienced by retailers may differ materially from the level of costs imputed into retail tariffs
- The price signal in the NEM (and the price signals conveyed by parties willingness to enter into forward hedging contracts with generators) acts as the investment signal in the NEM. Investment is not mandated or centrally controlled by NEMMCO or other regulatory bodies
- High peak prices driven by short periods of high demand are expected and necessary under the energy-only market design. Prices that reflect underlying supply and demand will help induce appropriate investment in power stations, which in the case of peaking stations have to recover their investment in a relatively short operating span. Peaking stations that can respond to peak demand needs provide a more efficient model than installing surplus baseload capacity, which can never efficiently recover its investment if it operates over short periods, unless its costs of operation are otherwise subsidised. Likewise prices fully reflecting underlying supply and demand which provide attractive average revenues over sustained periods are more likely to incentivise the construction of baseload power stations, which more efficiently meet energy needs than peaking stations when operated on a continual basis. The roles of different types of station are illustrated in Box 2 below

3.4 Workings of the NEM (cont'd)

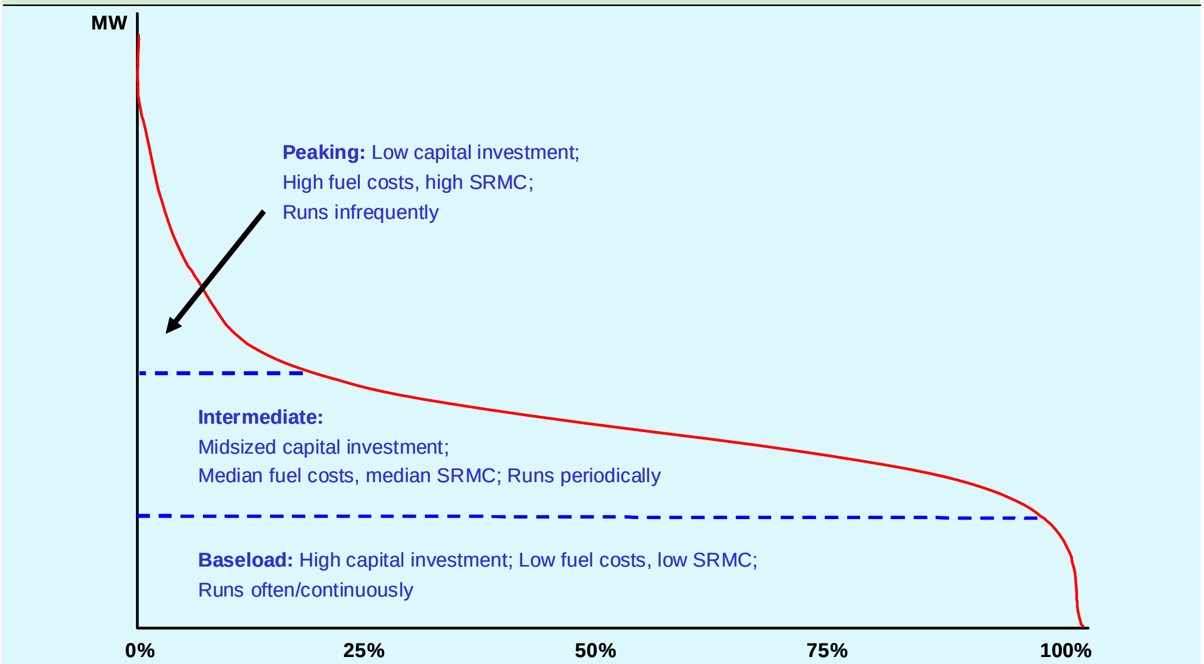
Box 2: Roles of Peak, Intermediate and Baseload Stations

Power stations in Australia are generally classified into the following broad categories:

- Baseload: which run more or less continuously, through the day and night, at high capacity factors. This plant generally has low ongoing fuel and operating cost, and in Australia has generally been coal fired plant. These stations generally take some time to "ramp up" to meet demand, and are not designed to respond rapidly to short-term events. Baseload stations have capacity factors up to and around 90%
- Peak: which are stations that are almost the inverse of baseload; generally open-cycle gas turbines that can often run on diesel fuel as backup, with low capital cost but relatively high fuel costs, these stations can respond quickly to market events and can "ramp up" quickly. Such stations are the cheapest way to meet high weather driven demand that may only occur a few days every year—installing baseload style plant, with high capital costs, to run for only short periods each year would be uneconomical. Peak stations would rarely have capacity factors exceeding 15% and very often under 10%, and may not run for long durations during periods of modest demand
- Intermediate: plant that sits in between peak and baseload plant and that might run, for example, during peak hours during weekdays, but less often overnight and on weekends when demand is typically lower. Intermediate plant has capacity factors broadly around 50%. CCGT and black coal plants comprise significant proportion of current and likely future intermediate plant in NSW

The common way to think about demand in the NEM is through what is called a 'load-duration curve'. This maps demand against time. The left hand side of the chart shows peak demand, which occurs only a small percentage of the time. The right hand side of the chart shows demand levels that form the base level of demand that occurs during low demand points, but is often exceeded—this ever-present 'base' demand level gives baseload generation its name. Exhibit 2 below shows a typical load duration curve and illustrates the roles of peak, intermediate and baseload generation.

Exhibit 2: Typical Load Duration Curve



3.4 Workings of the NEM (cont'd)

In the NEM a dispatch price is determined every five minutes, and six dispatch prices are averaged every half-hour to determine the spot price for each trading interval for each of the regions of the NEM. Each region has its own spot price, and these will frequently differ due to the prevailing economics of the predominant fuel supply in that region, loss factors, and transmission constraints between regions.

NEMMCO uses the spot price as the basis for the settlement of financial transactions for all energy traded in the NEM. Retailers and generators then separately settle amounts due under derivative contracts between them, so that difference payments between the parties account for the differences between the outcomes in the pool and the financial outcomes entered into under various hedging contracts.

The Rules set a maximum spot price of $10,000 per megawatt hour, and a minimum price of minus $1,000. The maximum price at which generators can bid into the market is also called Value of Lost Load ("VOLL") and it is an important part of the overall market economics and reliability framework as described below.

We have looked at experiences in other markets for evidence of responsiveness of generation development to wholesale market price signals. Selected examples are set out in Boxes 3 and 4 below. These examples suggest that generation supply can respond efficiently and rationally to prices set in the wholesale market.

Box 3: Lessons from Other Markets: Generation Response to Market Price Signals

Norway and Sweden

Prices in NordPool are below entry cost for new generators, which is evaluated at a minimum of 25 – 30 NOK/MWh. Low prices have been a major factor in discouraging investment in power generation and seem to have contributed to the closure of some peaking plants in Sweden. Since 2000, prices have risen steadily in both Norway and Sweden, which has provoked public concern and led to investigations in the Swedish market. However, these 'high' prices are still considered to be below entry costs and hence they may not be enough to create incentives for electricity generation investment…

…Investment has been modest in Norway and Sweden over the last decade. This has actually resulted in a slight decrease in installed capacity in recent years. Reserve margins fell in Sweden in the years after liberalisation. They remain, however, at more than 20 per cent in both countries, although this is less significant in Norway because of its reliance on hydroelectricity.

A key factor explaining the weak investment performance is wholesale prices well below entry costs for new generation. Much new investment has been directed towards technologies which are eligible for subsidies. Low prices have been a particular problem for investment into peaking capacity. Seasonal and annual variations are very large depending on rainfall and winter temperatures.

Entry into the generation markets of Sweden and Norway is limited, particularly in Norway, by a significant number of policies and procedures that restrict the choice of technology and make obtaining authorisations difficult. However, policy constraints did not appear to play a major role in a context in which low prices rendered most investments unprofitable. Policy barriers to investment could become binding in a different context, should prices rise high enough to induce investment.

Source © OECD/IEA, 2002, Security of Supply in Electricity Markets. Evidence and Policy Issues. International Energy Agency 2002

Box 4: Lessons from Other Markets: Generation Response to Market Price Signals

United Kingdom

Subsequent to the closure or mothballing of a number of plants in 2002 and 2003, following low wholesale electricity prices, capacity margin forecasts for the 2003/2004 winter in Britain tightened considerably, to around 16%.

The market reaction to this tightening was increases in forward prices for late calendar 2003/early 2004 for both baseload and peak pricing.

The price increases in turn motivated some generators to bring back on line some previously mothballed plants for the tight winter period. The result of this activity was that capacity margin returned to over 20% by January 2004. The operation of the market in this case appears to have followed a logical price-driven supply and demand sequence.

Source Morgan Stanley research

3.4 Workings of the NEM (cont'd)

The NEM rules, adequately high level of VOLL and transparent compulsory pool structure in our view will help wholesale prices reflect prevailing supply and demand balances, and incentivise the appropriate generation response. We note the comments of the IEA in its recent review of the Australia energy markets in Box 5 below.

Box 5: Comments from IEA on Australian NEM

Government can seek to guarantee security directly through ownership of the electricity supply industry's assets or through the creation of a suitably regulated market in which private actors participate. What Australia has done well is to avoid framing the problem as a trade-off between security and market efficiency. It has instead used market incentives and resulting efficiencies as a guarantor for security.

Source © OECD/IEA, 2005, Energy Policies of IEA Countries, Australia, 2005 Review

We also noted the comments of Intergen, the only private sector developer of coal-fired baseload plant in the NEM, is its submission to the review, repeated at Box 6 below.

Box 6: Intergen Comments on Price Signals

"… from this experience IGA recognises that the electricity market, functioning free of externally imposed distortions, sends effective signals about the required timing, type and size of new generating capacity"

and

"InterGen considers that no changes to the energy only market design are needed to ensure adequate investment. The NEM is very successful at creating signals and incentives. The price signals it sends reflect the effects of government interventions"

Source Intergen Australia submission to the Owen Inquiry, June 2007 and further correspondence with Morgan Stanley

3.5 Security and Reliability in the NEM

NEMMCO's "paramount objective is the management of power system security." [1]

For the purposes of this report, we have adopted the distinct definitions of "security" and "reliability" set out below, both for consistency but also to distinguish between these different but related concepts in a clear way. Security and reliability are not the same and NEMMCO prioritises each system security over reliability.

Longer-term power system security and reliability (and efficiency for that matter) can only be achieved through a combination of technical, economic and regulatory factors acting together and in concert. If there is a failure in any one of these three key areas, it may not have immediate short-term consequences but is certain to in the longer-term.

The security and reliability interpretations used in this report are set out below in Box 7, which has largely been sourced from NEMMCO and Reliability Panel documentation. Note that these standards differ from household reliability standards, as these exclude local distribution network performance. Where unserved energy is the result of a controlled response to prevent power system collapse due to multiple unanticipated disruptions, rather than as the result of insufficient generation or bulk transmission capacity being made available, it should be noted that this is formally classified as a security issue and is not considered part of the Reliability Standard.

Box 7: Security and Reliability Definitions and Settings

Security

Security of electricity supply is a measure of the power system's capacity to continue operating within defined technical limits despite the disconnection of a major power system element, such as a generator or interconnector.

The maintenance of power system security ensures the ongoing and reliable supply of electricity to satisfy demand at all times.

Power System Reliability

Reliability is a measure of the power system's capacity to continue to supply sufficient power to satisfy customer demand, allowing for the loss of generation capacity. The shortfall of supply against demand is referred to as unserved energy. Reliability standards are established in the NEM that determine that unserved energy per year for each region must not exceed 0.002 percent of the total energy consumed in that region that year.

The Reliability Standard for Bulk Energy Supply

The reliability standard was set at no more than 0.002% unserved energy (USE) 'over the long-term' by the Panel at market start in 1998 and has remained unchanged since that time. The standard describes the minimum acceptable level of bulk electricity supply measured against the total demand of consumers. The practice to date has been to measure the standard over the long-term. The standard does allow for significant variations from year to year providing the long-term average is within the standard. Currently, in order to operationalise the standard, NEMMCO calculates minimum reserve levels for each region. It then compares forecast and actual reserve levels with those minimum levels to manage against the risk that the reserve standard will not be met at the time of dispatch.

Supply Reserve

The power system is required to be operated at all times with a certain level of reserve in order to meet the required standard of supply reliability across the NEM. Calculation of the minimum reserve requirements recognises reserve sharing in a national context. Under current standards, NEMMCO is required to ensure 850 MW of reserve is carried across the entire NEM—including during periods of extreme demand—to provide the required level of supply reliability.

Source An Introduction to Australia's National Electricity Market, NEMMCO, June 2005 and the Comprehensive Reliability Review Interim Report, Australian Energy Market Commission, AEMC Reliability Panel, March 2007

Notes

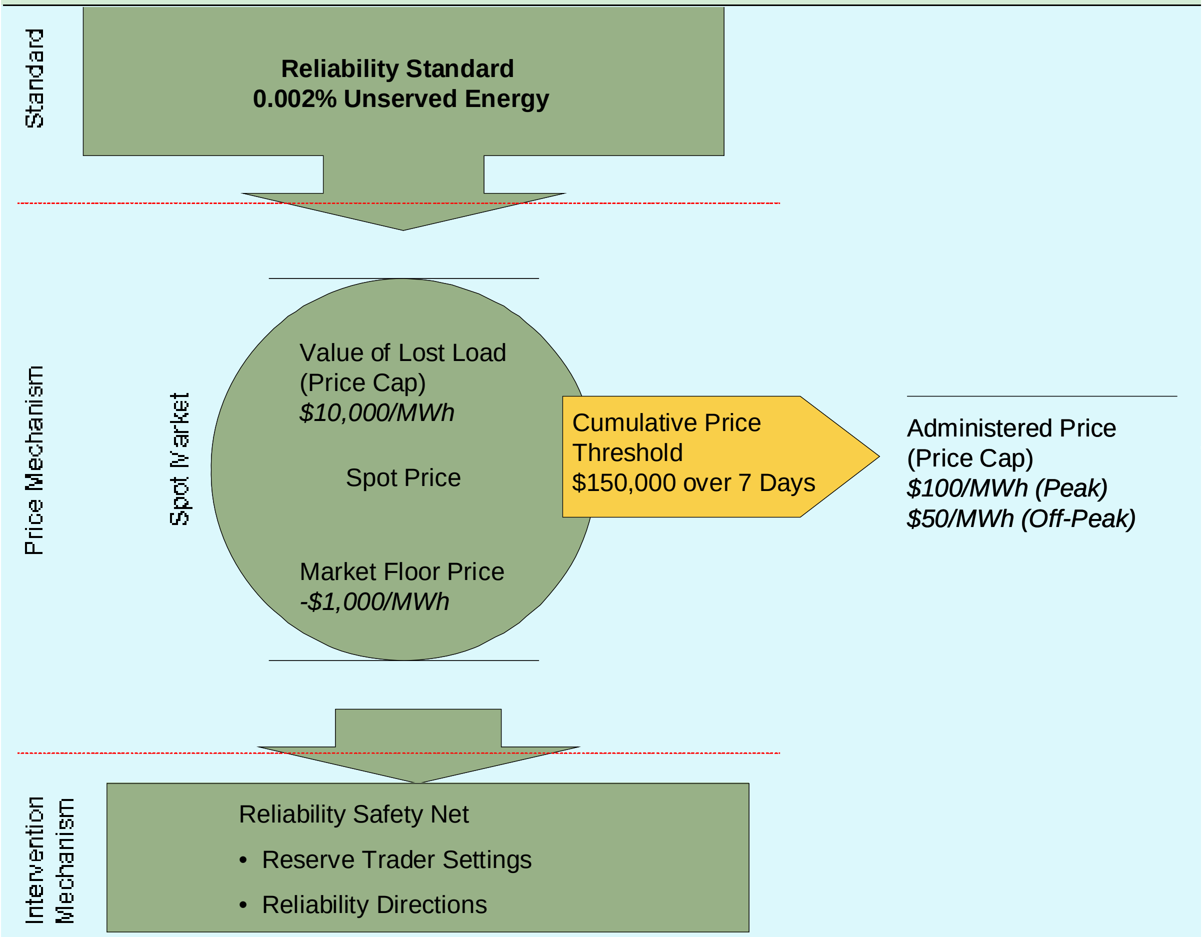
1. NEMMCO 2006 Annual Report

3.5 Security and Reliability in the NEM (cont'd)

The reliability settings in the NEM include price mechanisms, but also safety net or intervention mechanisms in the event that reliability is threatened. These are depicted in Exhibit 3 below. It is important to note that volatility in electricity prices and the VOLL price cap are deliberate and important parts of the overall reliability settings:

- Under the energy-only gross-pool design of the NEM, high prices at time of scarcity are required to reward investment in needed capacity
- VOLL is a price cap and it is important that it is set at a high enough level so that the level of the cap minimises the amount of revenue lost due to its existence, since too low a cap may limit revenues that would otherwise be available to reward investment in needed capacity. As such, the pricing mechanisms in the market are an important part of designing reliability in to the market itself. While $10,000/MWh may seem like a high figure relative to average prices closer to $40/MWh, credible estimates of the value of reliability for different categories of customers (e.g. Smelters) exceed the current level of VOLL

Exhibit 3: Schematic of the NEM Reliability Settings



Source Comprehensive Reliability Review Interim Report, Australian Energy Market Commission, AEMC Reliability Panel, March 2007

3.6 Tools for Managing Security and Reliability

In normal circumstances, security is rarely threatened in the NEM. Peak demand in the system tends to occur over a number of hours on a few days every year, driven by high summer temperatures. This generalisation is particularly true for the Victorian and South Australian electricity systems, where peak demand tends to be weather driven and these two adjacent states also tend to experience similar weather patterns at similar times. However, in circumstances where system security or reliability of supply is threatened, NEMMCO has the authority to use a variety of tools to restore balance to the system. The tools include the power of directions, load shedding and reserve trading set out in Box 8 below. Appropriately used, these 'safety net' provisions provide a buffer to system reliability that should not deter normal investment behaviour.

Box 8: NEMMCO's Tools for Security and Reliability

Security and Reliability Directions

NEMMCO has the power to direct registered generators into production when a supply shortfall is expected and some generators are known to have withheld some of their total capacity from the market. NEMMCO only uses this power of direction to protect power system security or supply reliability.

Load Shedding

In the event that demand in a region exceeds supply and all other means to satisfy demand have been implemented, NEMMCO can instruct network service providers to disconnect some customers. This action is only taken when there is a need to reduce demand and return the system to balance. Load shedding implemented in this way results in serial blackouts across areas serviced by the NEM.

The load shedding process is undertaken because system security is a higher priority than reliability in that the operating condition of the entire power system must be safeguarded as a priority to interrupting supply to part of the network. During a period of load shedding, supply is withdrawn from those NEM regions affected by the shortfall in proportion to the demand levels at the time the shortfall began. The proportioning process determines the amount of load shedding for each affected region up to the point were interconnectors are operating to their maximum transfer capacity. Once the interconnectors reach their maximum transfer capacity, the importing region must bear any additional load shedding locally.

By implementing load shedding, NEMMCO protects the integrity of power system operation so that widespread and long-lasting blackouts are avoided. It also ensures that the hardship caused by a sustained supply shortfall is shared in an equitable fashion.

Reserve Trading

When there is sufficient notice of an upcoming shortfall of supply that threatens to compromise minimum reserve margins, NEMMCO may tender for contracts for electricity supply from sources beyond those factored into NEMMCO's usual forecasting processes. At these times, Emergency generators and other generators connected directly to the distribution network who submit tenders may enter contracts to boost supply in the NEM so the widespread supply interruptions that may otherwise have occurred can be avoided. In the same way, some electricity consumers may offer for a financial consideration to decrease their demand at times of supply shortfall so that demand and supply are brought into balance.

Source An Introduction to Australia's National Electricity Market, NEMMCO, June 2005

3.7 The NEM's Performance Against the Reliability Standard

The Reliability Panel's most recent assessment of the NEM's performance against the reliability standard is contained in its Annual Market Performance Review ("AMPR") 2005–2006. (1) The Reliability Panel reported that for the measurement period since market start in 1998, the long-term averages for unserved energy due to supply shortfall were as follows:

- New South Wales, 0.0001%
- Queensland, 0%
- South Australia, 0.0025%
- Victoria, 0.0101%

In practice there has been high reliability of generation in the NEM, with two instances of generation failing to meet demand as measured by the reliability standard:

- South Australia and Victoria fell outside the reliability standard in the year 2000, when industrial action coincided with high demand and temporary loss of generating units in Victoria during January and February. Load shedding resulted. In every year since then, both states have met the reliability standard. Because the reliability standard is measured since market start, it is due to the 2000 event that the long-term averages in South Australia and Victoria remain outside the standard
- An incident in NSW on 1 December 2004 caused by generation unit failure at a time of record summer demand. A relatively small amount of load was voluntarily shed, and the shed load began to be restored after 10 minutes

Other than for the December 2004 incident, the Reliability Panel reported that there had been sufficient capacity from the energy market to meet consumer demand at all times and in all regions for the fifth consecutive year.

We note that the reliability standard measures events that are defined as 'credible contingency events,' which in broad terms means events that are reasonably possible in the circumstances, and which the design of the power system should be able to cater for—so credible contingency events which do cause disruptions will therefore affect performance against the reliability standard. It excludes 'noncredible' events which are not considered 'reasonably possible' in the circumstances, namely multiple simultaneous disruptions, which would not normally be catered for in market design, as only extraordinary system redundancy could cope with such events. There have been noncredible events in the system in recent years involving generation and transmission lines, but these fall outside the market standard definition of reliability.

It is important to note that the long-term averages of system reliability were based on only seven years' experience, a relatively short span of time given the recentness of the NEM, the gradual absorption of prevailing excess supply, and the investment timeframes for equipment of 20–40 years. It would not be prudent to rely solely on these results to conclude that there will not in the future be any problems with reliability.

Notes

1. Located on the AEMC's website at www.aemc.gov.au.

3.8 Adequacy of Reserve Levels

Reliability Panel

The Reliability Panel reported in the 2005–2006 AMPR that, overall, there has been a general reduction in forecast and actual shortfalls in reserves in each region over time such that they have fallen below the NEMMCO-determined minimum reserve levels [1]. NEMMCO determines these reserve levels through projecting a minimum amount of generation capacity that will deliver the reliability standard in each region (that is, an expected USE of 0.002%), assuming a demand condition that has all regions at their maximum 10% POE demand and taking into account reserve available across interconnectors. This is shown in Table 7.

Table 7: Duration Below the Minimum Reserve Levels [1]

	Year	Qld	NSW	VIC	SA
Forecast Duration Below the Threshold (Hours)	2005–2006	0	0	0	0
	2004–2005	17.5	0	0	6
	2003–2004	11.5	4.5	17.5	645
	2002–2003	2.5	3.5	7	115.5
	2001–2002	1	0	0	45.5
	2000–2001	188	8	67	716
	1999–2000	43	33	145	699
Actual Duration Below the Threshold (Hours)	2005–2006	0	0	0	1
	2004–2005	0	2	0	0
	2003–2004	0	1	4	6
	2002–2003	0	1	0	0
	2001–2002	0	0	0	0
	2000–2001	0	0	3	24
	1999–2000	5	4	36	88

Notes
1. Reliability Panel, Annual Market Performance Review 2005–2006

Impact of the Drought on Reserve Levels

NEMMCO recently released two reports on the impact of the drought on electricity supplies in the NEM [2]. These reports looked at the impact of low and average rainfall impacts on generation supplies from 2007 to early 2009. They found that the drought could impact both capacity (reduction in the power of generators) and energy production of generators over time under both average and low rainfall scenarios, albeit the most recent modelling, post significant rainfalls, projected much more modest effects on the potential risk of USE.

It is clear that drought impacts can materially affect generation supply, unless and until generation moves (where possible) to (i) use of nonpotable manufactured water supply that does not compete with other sources of demand in a drought, or is sea-water cooled where this is available (ii) dry cooling.

Notes
1. Located on the AEMC's website at www.aemc.gov.au.
2. NEMMCO, Potential Drought Impact on the Electricity Supplies in the NEM, Final Report, May 2007, and Drought Scenarios Investigation, August 2007 Update

3.8 Adequacy of Reserve Levels (cont'd)

In our discussions with private sector investors it has been clear that the private sector is reacting to the drought in its new investment planning, by expecting higher water pricing in the future (which will flow into electricity prices) and is also planning dry-cooled power where possible, expecting that potable water usage will be restricted.

What we find a little surprising is that:

1) Notwithstanding drought conditions in the adjacent New Zealand market in 2001 and 2003, which resulted in energy restrictions, and drought-driven issues in other electricity markets internationally, planning and forecasting for drought appears to have had little focus in the NEM until recently

2) The potential impact of drought conditions on future electricity supplies was the source of public comment by mid-2006. Notwithstanding this, prices did not appear to respond until early this year, and consumers did not appear to bring forward their periodic recontracting despite the risk that drought could impact materially on supply and hence prices

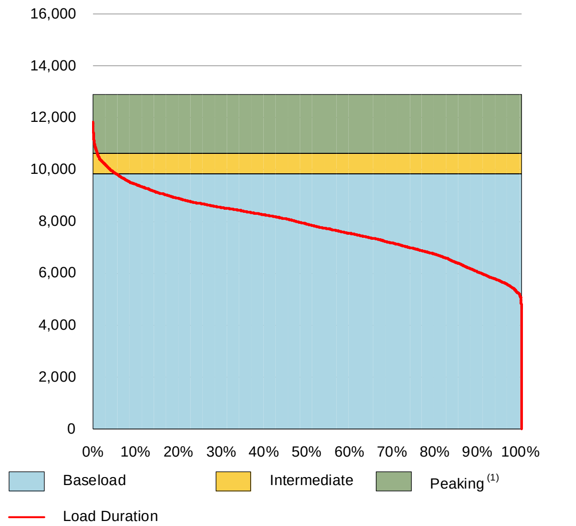
3.9 How the NEM Has Delivered New Investment

At the commencement of the NEM in 1998 there was a significant oversupply of baseload generation in the two largest states of New South Wales and Victoria. At the same time, there was relatively less peak generation capacity, and South Australia had a tighter supply-demand balance.

In the exhibits below we set out generation capacities as against load duration curves for NSW, QLD, VIC and SA for 2000 and 2006. In NSW, it is clear that the state has historically had a very large baseload fleet and peak supply via Snowy. With a rise in overall demand levels from 2000–2006, signals for new investment are emerging.

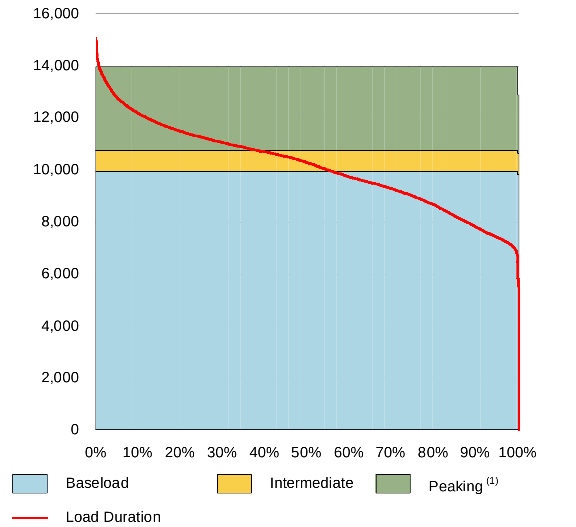
Exhibit 4: NSW Supply-Demand Balance 2000–2006

NSW 2000 Demand vs. Capacity
Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006, Company Releases, Industry Reports, Various Publications

NSW 2006 Demand vs. Capacity
Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006, Company Releases, Industry Reports, Various Publications

Notes

1. Peaking includes maximum interconnector power transfer capability from Snowy into NSW. Morgan Stanley has multiplied generation capacities availability factors to derive the supply-demand balance

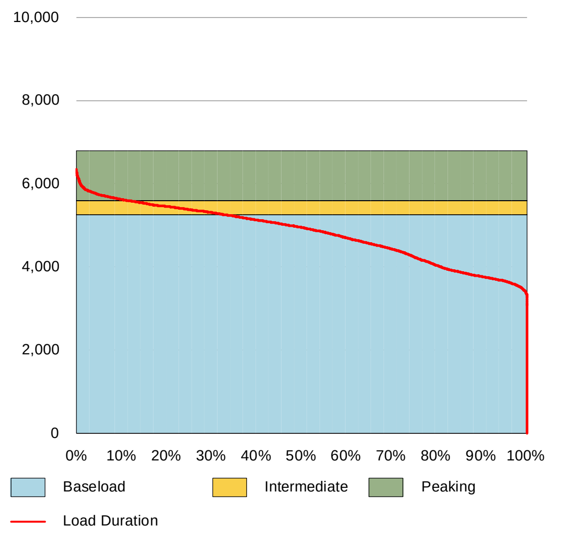
3.9 How the NEM Has Delivered New Investment (cont'd)

In Queensland, significant investment in all types of generation has kept pace with and/or exceeded demand growth, with plentiful baseload supply. Some of this Queensland generation is now exporting into NSW.

Exhibit 5: QLD Supply-Demand Balance 2000–2006

QLD 2000 Demand vs. Capacity

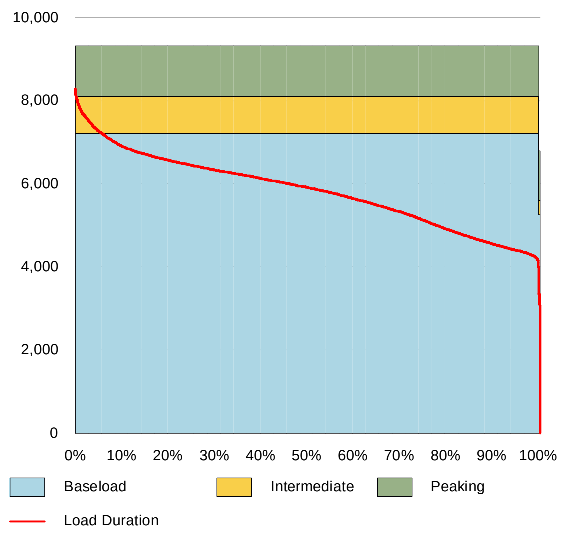
Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006

QLD 2006 Demand vs. Capacity

Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006

Notes

1. Morgan Stanley has multiplied generation capacities by availability factors to derive the supply-demand balance

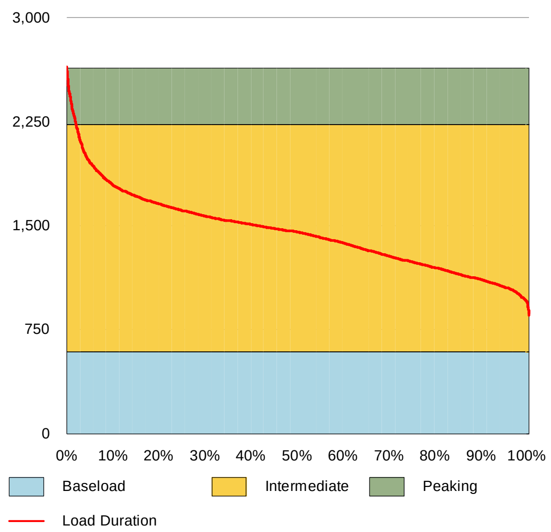
3.9 How the NEM Has Delivered New Investment (cont'd)

South Australia is the most 'peaky' market in the NEM, and is well supplied by intermediate and peak generation. Relative to other states South Australia had a lower proportion of baseload in its supply mix on formation of the NEM.

Exhibit 6: SA Supply-Demand Balance 2000–2006

SA 2000 Peak Demand vs. Capacity

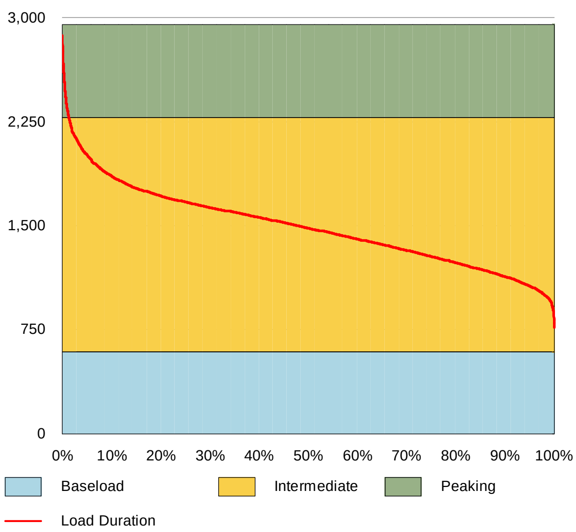
Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006

SA 2006 Peak Demand vs. Capacity

Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006

Notes

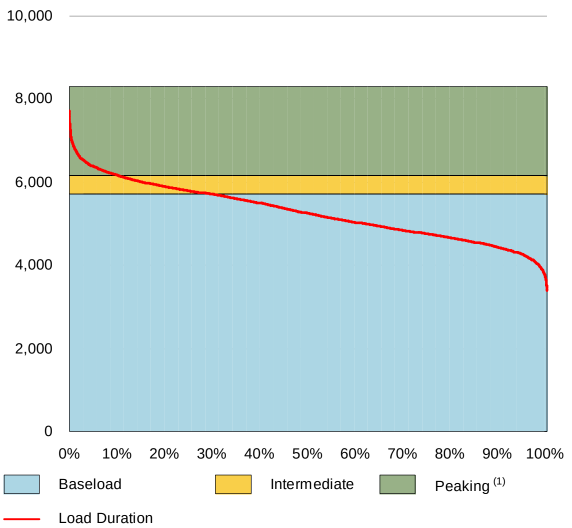
1. Morgan Stanley has multiplied generation capacities by availability factors to derive the supply-demand balance

3.9 How the NEM Has Delivered New Investment (cont'd)

In Victoria, in 2000 the baseload capacity covered much of the demand, with only peak demand exceeding baseload capacity. Growth in demand from 2000–2006 has further balanced supply with baseload now covering around the bottom 50% of supply, with the balance of the demand met through peaking and intermediate generation, and interconnection. This explains the investment in peaking generation by a number of parties in the region. Note that these charts do not factor in the Basslink connection with Tasmania which also augments supply to Victoria.

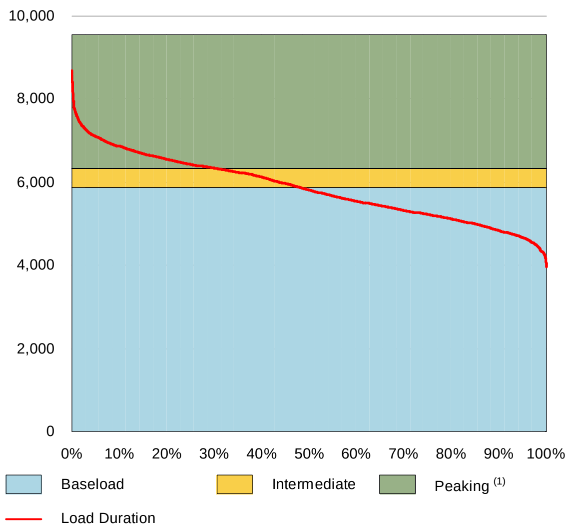
Exhibit 7: VIC Supply-Demand Balance 2000–2006

VIC 2000 Peak Demand vs. Capacity
Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006

VIC 2006 Peak Demand vs. Capacity
Load Duration Curve, Generation Capacity



Sources NEM Review, ESAA Electricity Gas Australia 2006

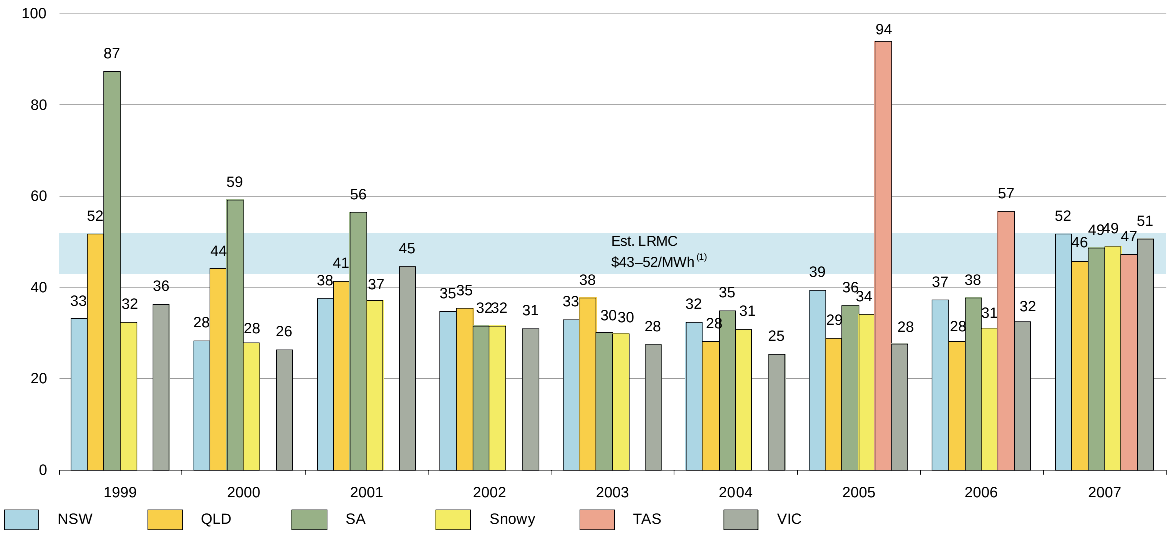
Notes

1. Peaking includes maximum interconnector power transfer capability from Snowy into VIC. Morgan Stanley has multiplied generation capacities by availability factors to derive the supply-demand balance

This surplus in baseload capacity generally and particularly in NSW and Victoria early this decade has been reflected in average wholesale electricity prices which have been below the long-run marginal cost of new capacity. Generators consequently have not, on average, been able to bid capacity at prices which support new baseload generation investment. There has been little need for the private sector to commit to baseload projects in recent years, as the economics in the wholesale market have not justified it, with average prices being noticeably flat across 2002–2005 in the mainland NEM states. This period also coincided with increased interconnection and relatively low transmission constraints being experienced in 2002 and 2003 (refer Section 3.11).

3.9 How the NEM Has Delivered New Investment (cont'd)

Exhibit 8: Average Annual Pool Prices by State
YE June



Source NEMMCO data, Frontier Economics Reports to IPART April 2007

Notes

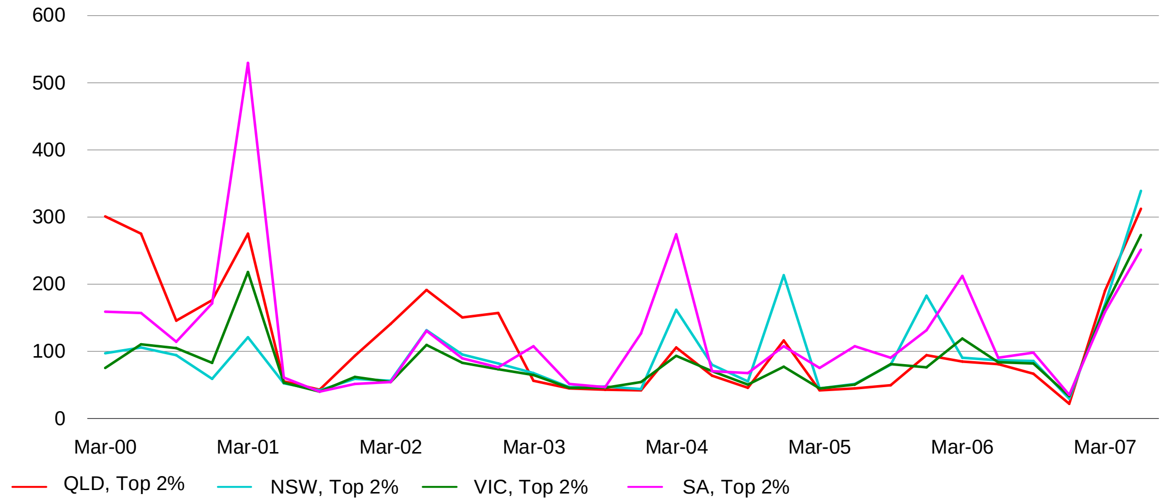
1. Based on estimates for the LRMC (energy-only) of energy purchased by NSW retailers by Frontier Economics, Energy Costs, prepared for the Independent Pricing and Regulatory Tribunal

Price spikes have brought on new peak investment, especially in VIC and SA around the start of the decade, and it is noticeable that the investment early in the decade in Queensland and SA appeared to result in a drop in pool prices in those regions, but this also reflected increased interconnection (Queensland interconnected from the second half of 2000, SA increased interconnection in late 2002). Only recently have average prices risen above those required to justify new nonpeak generation investment. However, this is in part a result of water constraints resulting from the drought and whether this will be sustained into the medium-term is unclear. What is relevant to an investor is the post-investment wholesale price outcomes. In order for new investment to be triggered, prices need to rise to levels that, adjusted for the impact of the new investment, will provide acceptable economic outcomes.

Exhibits 9 and 10 below show peak period prices in the different NEM regions over recent years, and highlight the peakiness of the top few percent of time (typically hot days), the weather-driven season ability, and generally more subdued behaviour from 2002 to 2006.

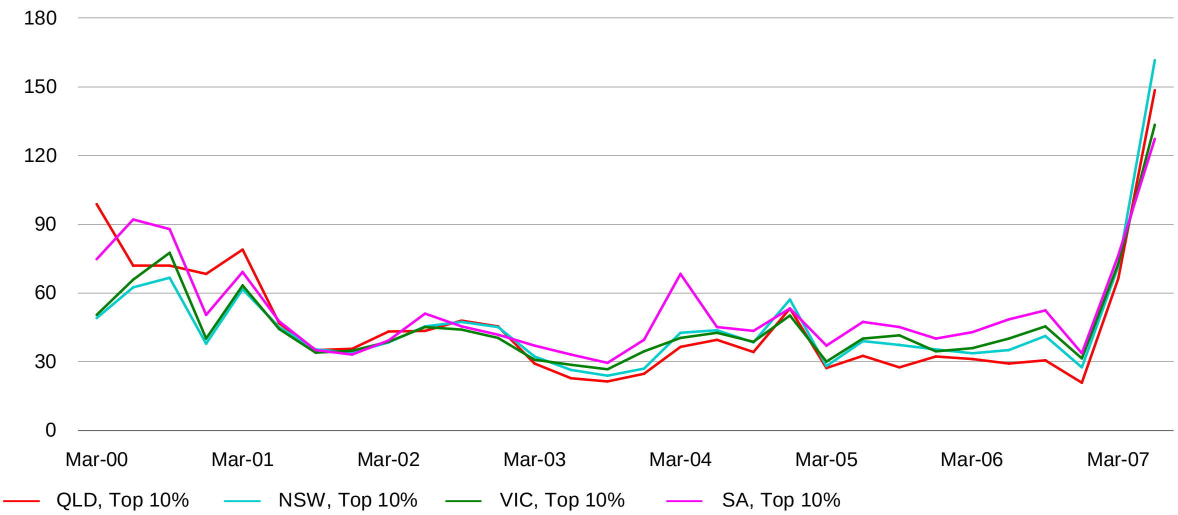
3.9 How the NEM Has Delivered New Investment (cont'd)

Exhibit 9: Peak Pool Prices by State
Top 2% Percentile Price (A$)



Source NEMMCO data

Exhibit 10: Peak Pool Prices by State
Top 10% Percentile Price (A$)



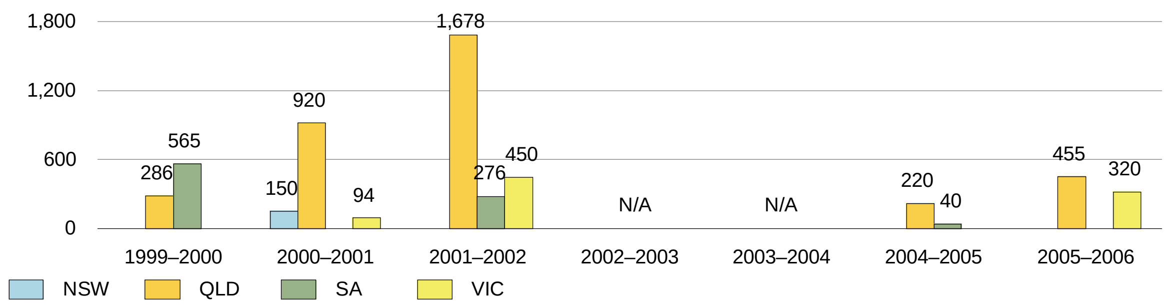
Source NEMMCO data

Notwithstanding the supply-demand balance at the commencement of the NEM, significant power station development has taken place in the NEM since 2000. It is noteworthy, and supportive of the NEM price mechanism, that investment in Queensland, SA and Victoria at the beginning of the decade (refer Exhibit 11 below) tends to be aligned with the higher-priced peak and average periods shown in the figures above, and that there has been little new investment in the period 2003–2006 when prices have been relatively flat.

3.9 How the NEM Has Delivered New Investment (cont'd)

Private sector investment to date has been made largely in peak and intermediate plant, and have been driven by volatility of electricity prices, rather than average electricity price levels. Volatility is to be expected, and in an energy-only market like the NEM plays an important role in incentivising new investment and is a deliberate part of the market design for reliability as noted earlier in this section.

Exhibit 11: Annual Investment in New Generation Capacity [1]
MW



Source NEMMCO, based on registered capacity data

Notes
1. These are gross investment estimates that do not account for decommissioned plant. Excludes power stations not managed through central dispatch

Excluding intermittent wind generation of 817 MW (as at 2006), [1] and ongoing unit upgrades and enhancements to existing plant, these new developments are described in Table 8 below. Notwithstanding the historic surplus in generation supply, since 2000, approximately 9,000 MW of new generation capacity has been built in the NEM, or is to Morgan Stanley's understanding, currently committed. This excludes intermittent wind generation which has been driven by the MRET subsidiary. In addition to these actual committed developments, there are at least a further 20–30 further power projects under consideration across the NEM by a variety of developers.

Table 8: Significant Power Station Developments in the NEM Since 2000

Power Station	Year of Actual/ Initial Operation	State	Capacity MW	Technology	Developer	Development Driver
Pelican Point	2000	SA	485	Gas (CCGT)	International Power	Merchant—portfolio generator
Ladbroke Grove	2000	SA	80	Gas (OCGT)	Origin	Vertical integration with retailer
Oakey	2000	Qld	286	Gas (OCGT)	Babcock & Brown/ERM	PPA with Enertrade
Callide C	2001	Qld	920	Coal	CS Energy/InterGen	Merchant—portfolio generator (Public-Private JV)
Redbank	2001	NSW	150	Coal	National Power	PPA with Retailer
Bairnsdale	2001	Vic	94	Gas (OCGT)	Duke Energy	PPA (network support contract)/merchant
Tarong North	2002	Qld	443	Coal	Tarong Energy/TEPCO	Merchant—portfolio generator (Public-Private JV)
Swanbank E	2002	Qld	385	Gas (CCGT)	CS Energy	Merchant—portfolio generator—Government investment
Millmerran	2002	Qld	850	Coal	InterGen	Merchant—portfolio generator
Hallett	2002	SA	180	Gas (OCGT)	AGL	Vertical integration with retailer
Quarantine	2002	SA	96	Gas (OCGT)	Origin	Vertical integration with retailer
Valley Power	2002	Vic	300	Gas (OCGT)	Edison Mission Energy	Merchant—portfolio generator
Somerton	2002	Vic	150	Gas (OCGT)	AGL	Vertical integration with retailer

Notes
1. Per Auswind submission to the Owen Inquiry

3.9 How the NEM Has Delivered New Investment (cont'd)

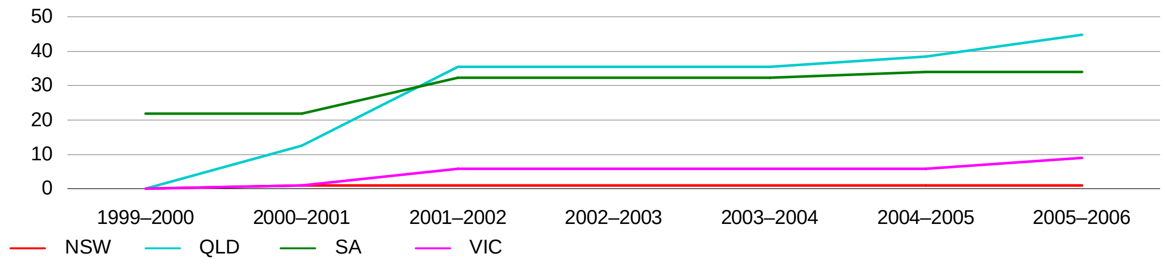
Table 8: Significant Power Station Developments in the NEM Since 2000

Power Station	Year of Actual/ Initial Operation	State	Capacity MW	Technology	Developer	Development Driver
Angaston	2005	SA	40	Oil	Infratil	Vertical integration with retailer
Yabulu	2005	Qld	220	Gas (CCGT)	Transfield	PPA with Enertrade
Braemar	2006	Qld	455	Gas (OCGT)	Babcock & Brown	Part PPA/Long-term hedge contract with retailer
Laverton North	2006	Vic	320	Gas (OCGT)	Snowy Hydro	Merchant—portfolio generator—Government investment
Kogan Creek	2007	Qld	750	Coal	CS Energy	Merchant—portfolio generator—Government investment
Quarantine Expansion	2008	SA	120	Gas (CCGT)	Origin	Vertical integration with retailer
Tallawarra	2008 (1)	NSW	400	Gas (CCGT)	TRUenergy	Merchant—portfolio generator/future vertical integration
Bogong	2009	Vic	140	Hydro	AGL	Vertical integration with retailer
Munmorah GT	2009	NSW	667	Gas (OCGT)	Delta	Merchant—portfolio generator
Uranquinty	2009	NSW	640	Gas (OCGT)	Babcock & Brown	Merchant—portfolio generator
Braemar CCGT	2010	Qld	630	Gas (CCGT)	Origin Energy	Vertical integration with retailer

Sources ESAA and Morgan Stanley analysis

Exhibit 12 below shows that while most growth in absolute MW terms has occurred in Queensland, generation expansion growth in South Australia has been just as significant when measured as proportion of capacity. NSW has seen the least growth of all the states.

Exhibit 12: Cumulative Growth in Net Generation Capacity Since 1999–2000 (1)
%



Sources ESAA, Morgan Stanley analysis

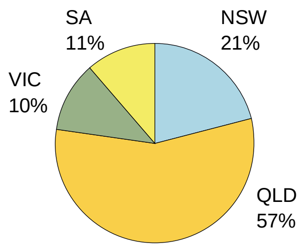
Notes

1. Gross generation capacity. Excludes reductions in capacity (e.g. deratings, decommissionings, etc.)

Most new generation in absolute terms has occurred in the high-growth state of Queensland, and in this case often funded by Government or in partnership with government entities. The Millmerran merchant power station was the only baseload power station built wholly by the private sector in the state in recent times, until Origin Energy's recent announcement that it was building a combined cycle baseload station at Braemar. Refer Exhibit 13 below.

3.9 How the NEM Has Delivered New Investment (cont'd)

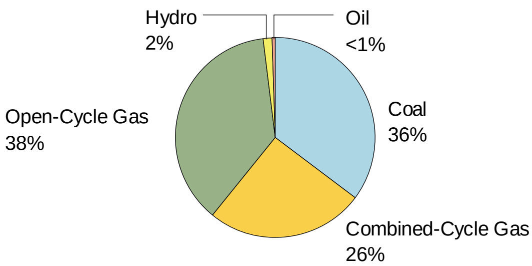
Exhibit 13: New Generation Investment by State
By MW, Since 2000 (Actual and Committed)



Sources ESAA, various public documents, Morgan Stanley Research

Most generation has been gas-fired, reflecting historical surpluses of coal-fired baseload plant and increased peak demand growth in the market, with increased penetration of air conditioning contributing to escalating peak demand level. All coal-fired investment has been in Queensland. Refer to Exhibit 14 below.

Exhibit 14: New Generation Investment by Fuel Type
By MW, Since 2000 (Actual and Committed)

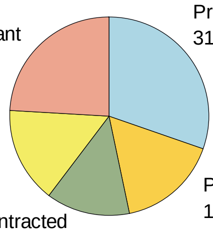


Sources ESAA, various public documents, Morgan Stanley Research

For non-government investment, new power plant has been significantly driven by retailers/vertically integrated parties, portfolio generators with an interest in the market expanding their fleet, or by developers contracting with government (often government-owned retailers) to build generation under contract. Notwithstanding significant government investment in Queensland, the private sector has developed (wholly or in joint venture) 75% of new generation in the NEM. Refer to Exhibit 15 below.

3.9 How the NEM Has Delivered New Investment (cont’d)

Exhibit 15: New Generation Investment by Investment Type
By MW, Since 2000 (Actual and Committed)



Source ESAA, various public documents, Morgan Stanley Research

The available data suggests the NEM has been effective in bringing about new generation development. While the apparent volatility is of concern to some market observers, this same volatility appears to have been the main driver of new investment, particularly in peak capacity, in an era where there has been a legacy of oversupply of baseload capacity. These investment motivations are articulated in Section 4.

We note in Box 9 below the following comment from the AER in its recently released report on the State of the Energy Markets in Australia.

Box 9: Extract from AER Report on Generation Investment in the National Electricity Market

“Figure 1.12 compares total generation capacity with national peak demand. The chart includes actual demand and the demand forecasts published by NEMMCO two years in advance. The chart indicates that the NEM has generated sufficient investment in new capacity to keep pace with rising demand (both actual and forecast levels), and to provide a ‘safety margin’ of capacity to maintain the reliability of the power system.”

Source AER, State of the Energy Market, July 2007. Refer Section 1.3

3.10 Timeliness of Investment Delivered by the Market in the Context of the Reliability Standard

Exhibit 16 below presents the number of years from each NEMMCO SOO to a projected shortfall of generation capacity for each region (except Tasmania). That is, the number of years from the publication of the SOO until, in the absence of appropriate investment, it was anticipated that the level of reserve generation would not meet the Panel's reliability standard. In particular, the exhibit shows:

- Considerable spare reserve in Queensland and New South Wales prior to 2001 which has reduced in recent years, converging to between two to five years' anticipation of when additional capacity will be required. This implies that new capacity has been built a considerable period prior to projected shortfalls of generation. Such responses included additional generation capacity and interconnector refinements but some of the apparent response was due to revisions to the minimum reserve levels for these regions. It should be noted that in Queensland, new power generation development has been dominated by the State, but in New South Wales, two of the three most recent committed plant have been driven by the private sector
- Shorter time horizons on average before requirement of additional capacity in Victoria and South Australia, including three years where the SOO projected a shortfall for the following summer. This implies that responses to anticipated shortfalls are happening closer to the time at which they are forecast to be needed. It should be noted that delays to the commissioning of Basslink and Laverton North power station are considered to have impacted these capacity shortfall projections

Exhibit 16: SOO Projections of Time Until Shortfall Against the Reliability Standard
Years to Shortfall

Sources Comprehensive Reliability Review Interim report, AEMC, AEMC Reliability Panel, March 2007

The following should be noted in reviewing Exhibit 16:

- The years to shortfall for New South Wales in the 2000 SOO and for Queensland in the 2000 and 2001 SOOs were reported as being beyond the 10-year outlook period (denoted as 11 years for presentation purposes)
- The 2003, 2004 and 2005 SOOs projected a generation shortfall for Victoria and South Australia for the following summers (2003/04, 2004/05 and 2005/06 respectively). In consequence NEMMCO used its reserve trader power for the 2004/05 and 2005/06 summers, although the contracted reserves were, in the event, not required
- Tasmania is not included in the figure

3.10 Timeliness of Investment Delivered by the Market in the Context of the Reliability Standard (cont'd)

It should be noted that notwithstanding these projections by NEMMCO, the market did in fact meet the reliability standards and the reserve trader reserves were not required.

The current two year Medium-Term Projected Assessment of System Adequacy issued by NEMMCO, which does not fully reflect every limitation imposed by drought conditions, is forecasting adequate reserves in all regions other than Queensland over this coming summer period which is drought affected, and also affected by planned maintenance outages. We understand that some of the drought-affected generation could be made available with 48 hours notice which may mitigate reserve adequacy issues.

We also note below the concluding comments of the Reliability Panel on the historical investment patterns and their implications for the outlook for reliability.

Box 10: Summary Comments of the Reliability Panel on the Implications of History for Outlook for Reliability

Historical analysis suggests that the reliability mechanisms are not always able to protect against the kind of extraordinary or coincident exogenous factors that were observed in South Australia and Victoria in 2000. The existing mechanisms also did not bring about sufficient capacity to allay NEMMCO's concerns in 2004 and 2005 that a high load scenario could breach the reliability standard, as a result of which NEMMCO contracted for reserve capacity. However it is unlikely that incidents such as these would have been prevented by adjusting the reliability standard or by redesigning the reliability mechanisms themselves. For that reason, the Panel's preliminary conclusion is that the reliability settings themselves, which are the focus of this Review, have performed satisfactorily.

As noted, delays to the commissioning of new generators can impact reliability when the design is only delivering 'just in time' outcomes. From that perspective the Panel considers that some prudence should be adopted when designing the mechanisms such that the reliability standard is not susceptible to ordinary events such as construction delays…

… The Panel's observations on these matters can be summarised as follows:

- The fundamentals of the market design are sound and, with the current settings, the reliability standard is likely to be met in the near-term, provided the fundamentals occur in practice
- However, there is increasing risk, in the medium to long-term, that reliability may be compromised if reduced investor confidence as a result of uncertainty about other policy settings created potential delays with new generation investment

…The Panel has concluded that while the basic format of the energy-only market appears able to allow the market to deliver revenue streams over the longer term that would sustain sufficient investment to meet the reliability standard, it is less clear that the external environment in which the market operates will allow the market to function freely enough to succeed.

Sources Comprehensive Reliability Review Interim Report, Australian Energy Market Commission, AEMC Reliability Panel, March 2007

3.11 Importance of Transmission in the NEM and NSW

NSW benefits substantially from interconnections with other regions of the NEM. NSW is a net importer of power from other regions. This reflects:

- The availability of substantial quantities of competitive generation from Queensland
- The treatment of the Snowy region as a separate region in the NEM, not withstanding its physical location partly inside NSW. Snowy in effect has been the main provider of peaking generation to NSW historically

Interconnector maximum transfer capabilities are set out in Table 9 below.

Table 9: Maximum Interconnector Power Transfer Capabilities into/out of New South Wales
As at June 2006

Interconnector	From	To	Market Flow Direction Power Transfer Capability into New South Wales (MW)	Market Flow Direction Power Transfer Capability out of New South Wales (MW)
QNI	QLD	NSW	1,078	589
Directlink (1)	QLD	NSW	196	152
Terranora (1)	QLD	NSW	234	30
Snowy	Snowy	NSW	3,559	1,150

Source Page 10–4, NEMMCO 2006 Statement of Opportunities

Notes

1. Directlink and Terranora form part of the same interconnector, following Directlink's conversion into a regulated interconnector on 21 March 2006. However, the transfer limits are measured at different points and therefore have different maximum transfer capabilities

While interconnection capacities are substantial, they can also be constrained. This means that supply in the exporting region is able to be transferred to the region of high demand. Table 10 shows historical intra-regional and interregional constraints. It shows connections between States are far more prevalent than within States, and that constraints between regions are increasing, not decreasing, and the pattern is also somewhat volatile. This suggests generation expansion and transmission augmentation are not as well coordinated as they could be. Given NSW is a net importer of energy from other regions, the performance of transmission (electricity and gas) should be a particular focus for Government. Comparing Table 10 and Exhibit 10 (top 10% peak pricing) is interesting, with less price separation between the States in 2002–2003 is consistent with the periods of low inter-regional constraint, with more frequent constraint (and price separation) post-2003.

3.11 Importance of Transmission in the NEM and NSW (cont'd)

Table 10: Historically Binding NEM Transmission Constraints
2001–2006

	Hours of Constrained Flow						% of Total Time Constrained					
Region	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**
Intra-Regional Constraints by Region												
Queensland	201	449	40	44	434	141	2.3	5.1	0.5	0.5	5.0	1.6
New South Wales	105	48	20	5	61	7	1.2	0.5	0.2	0.1	0.7	0.1
Snowy	–	–	54	18	58	–	0.0	0.0	0.6	0.2	0.7	0.0
Victoria	7	17	80	167	101	106	0.1	0.2	0.9	1.9	1.2	1.2
South Australia	–	–	–	–	–	51	0.0	0.0	0.0	0.0	0.0	0.6
Tasmania	–	–	–	–	62	163	0.0	0.0	0.0	0.0	0.7	1.9
Inter-Regional Constraints by Region (1) (2) (3)												
Queensland Import	193	243	380	47	131	477	2.2	2.8	4.3	0.5	1.5	5.4
Queensland Export	391	249	540	1,719	1,477	1,808	4.5	2.8	6.2	19.6	16.9	20.6
NSW Import	391	250	545	1,721	1,518	1,925	4.5	2.9	6.2	19.6	17.3	22.0
NSW Export	195	243	380	57	150	535	2.2	2.8	4.3	0.6	1.7	6.1
Snowy Import	715	437	636	1,051	716	264	8.2	5.0	7.3	12.0	8.2	3.0
Snowy Export	78	39	17	30	82	324	0.9	0.4	0.2	0.3	0.9	3.7
Victorian Import	94	102	181	74	63	299	1.1	1.2	2.1	0.8	0.7	3.4
Victorian Export	2,032	757	1,757	3,112	2,881	2,208	23.2	8.6	20.1	35.4	32.9	25.2
South Australian Import	1,319	319	1,121	2,071	2,185	1,798	15.1	3.6	12.8	23.6	24.9	20.5
South Australian Export	16	65	168	45	22	57	0.2	0.7	1.9	0.5	0.3	0.7
Tasmanian Import	–	–	–	–	–	204	0.0	0.0	0.0	0.0	0.0	2.3
Tasmanian Export	–	–	–	–	–	34	0.0	0.0	0.0	0.0	0.0	0.4

Source Page 13–27, NEMMCO 2006 Statement of Opportunities

Notes

1. FCAS constraint equations were not included in calculations for this table
2. Periods of constraint were identified using a filter of form 'MW flow (target) ≥ limit – 1 MW'
3. Inter-regional constraints by region (import and export) were calculated by adding the number of hours that any interconnector flow was constrained in the relevant direction (import or export) for all interconnectors applicable to the region. Whether or not the constrained flow across different interconnectors for a region were coincident was not taken into account in the summation

3.12 Sources of Interruptions to Service to Customers

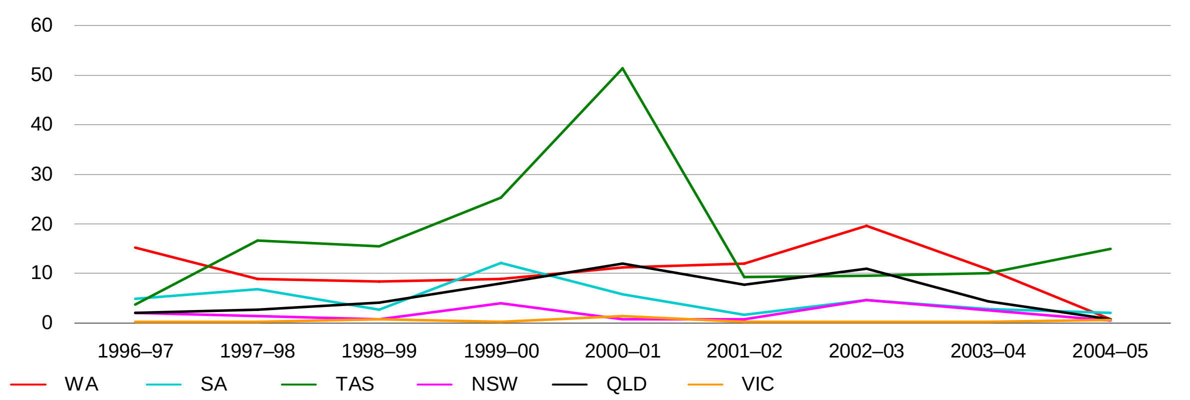
Power generation failure is only one source of potential interruption to end-users. Clearly, as the source of supply to the market as a whole, power generation failure has potentially wide significance. However as noted earlier, the NEM has been reliable when measured against the set standards.

Nongeneration elements in the physical supply chain also have considerable impact on end-users, who may experience the same outcomes from disruption regardless of where system faults occur, since from the end user perspective they can not distinguish between different sources of fault.

Transmission lines carry high voltage power over long distances from generation stations to demand centres (where they connect into distribution networks) and major industrial customers. Like generation, transmission line failure can have significant ramifications and bulk transmission disruptions are factored into the Reliability Standard. It should be noted that not all transmission events will fall within the definition of unserved energy. Recent examples of transmission disruption include the disruption to Victorian power supplies that occurred on 16 January 2007 due to bushfires tripping transmission lines, resulting in load shedding, and the damage to the Queensland transmission networks from Cyclone Larry on 20 March 2006.

Exhibit 17 below captures minutes off supply for major transmission systems across Australia. The data indicates high reliability, with fewer than ten minutes off supply due to transmission outages and faults, for all regions except Tasmania.

Exhibit 17: Transmission Outages—System Minutes Unsupplied [(1)]
Minutes



Sources ESAA, Electricity gas Australia 2006 and previous years

Notes

1. System minutes unsupplied is calculated as megawatt hours of unsupplied energy divided by maximum regional demand. ESAA data not available for Queensland and Western Australia in 2004–2005

3.12 Sources of Interruptions to Service to Customers (cont'd)

Distribution networks, the lower voltage 'poles and wires' that run to residential homes and business, are the most common source of disruption to supply. This is not surprising given the extent and spread of these networks and the numerous incidents and accidents that can affect power supplies in suburban networks (e.g. storm damage, falling branches etc.). Standards differ between states and between rural and urban customer categories. As a rough average, the System Average Interruption Duration Index ("SAIDI") for most urban/metropolitan customers for most customers around Australia varies between 1–2 hours based on 2004–2005 data, and significantly longer for rural customers. This indicates that local distribution networks are by far the largest contributors to end user disruptions for most consumers—not generation or bulk transmission.

We note below recent commentary from the AER on reliability and security matters.

Box 11: Extract from AER Report on Reliability in the National Electricity Market

There is a common perception that a lack of generation capacity or overloaded transmission systems cause most power system outages. As this essay will show, the Australian data indicates there is no chronic shortage of generation or transmission capability. Rather, when 'the lights go out' for electricity customers, it is generally caused by an issue in the local distribution network.

Sources AER, State of the Energy Market, July 2007. Refer Essay B

3.13 Morgan Stanley Conclusions on Private Sector Investment and NEM Reliability to Date

The submissions from stakeholders and discussions with potential generation investors, which are referred to in the following Section 4, revealed that the most significant risks to future investment in and timing of generation, hence reliability, are perceived to be the uncertainty arising from greenhouse policy and the risk of government intervention in the market. The effect on reliability outcomes of these two factors was generally considered to be of much greater significance than other normal commercial factors. These risks can and should be removed by governments to the maximum extent possible. It would be refreshing to see governments protect and champion a market structure, rather than to seek to directly deal in it to influence its outcomes, which has tended to be the practice to date.

Morgan Stanley notes that these concerns were also cited in the recent ERIG review cited at Box 12.

Box 12: Comments in ERIG Review on Threats to Private Sector Investment

Private sector operators cited government ownership, and particularly the apparent willingness of government owners of these assets to be guided in their investment decisions by drivers other than purely commercial considerations, such as political factors and/or desires for regional development, as one of the biggest impediments to private investment in the energy sector. Perceptions, strongly held, whether well founded or not, can be real barriers to market entry and timely capacity expansion.

Source A report to the COAG by ERIG, January 2007

We conclude this section of our report by noting the following:

- Reliability for end-users of electricity cannot be absolutely guaranteed regardless of cost. Some level of disruption in any substantial system is inevitable when measured across a substantial time period. The relevant questions for determining reliability are “how much do we need?’ and “what are we prepared to pay for the standard we want?”
- Reliability in the NEM has performed well against the set market standard of 99.998%, albeit over what is a fairly short period in the evolution of a market, and in a period where historic government over-investment in generation (in particular baseload) was still being absorbed
- The NEM appears to have worked surprisingly well given the number of actual and potential distortions imposed on it from a variety of external sources, in particular the proliferation of state based energy and renewables policies and instruments
- Centrally directed government investment experiences prior to the NEM start showed that government was relatively poor at ensuring an efficient investment profile for generation. Government historically over invested in total capacity, but also simultaneously over invested in capital-intensive baseload capacity, at a considerable cost to the community
- The market has delivered new investment, with a substantial amount of this coming from the private sector, particularly in wholly privatised markets. Absent externally imposed shocks or uncertainties there is no reason to expect that this will not continue. The private sector has hedged its risks (in retail) and taken other development opportunities where they have presented themselves, notwithstanding a legacy of excess supply in some markets
- There is a large number of power projects in the planning and development phase across the NEM, which suggests there is no lack of appetite by the private sector to invest, under the right conditions

3.13 Morgan Stanley Conclusions on Private Sector Investment and NEM Reliability to Date (cont'd)

- The market has delivered timely new investment. However the margin for error (as against the forecast minimum reserve standards) has at times been small, and NEMMCO has tendered for reserve trader on a number of occasions. Significant unforseen delays to completing construction of generation and transmission interconnection projects do have the potential to reduce system reserves and reliability below what might otherwise have been expected in the ordinary course. This is true regardless of whether new investment is created by the private sector or government entities
- The data suggests that market forces in the NEM have to date delivered new generation investment in line with the reliability standard, and that regulatory forecasts of threats to reliability may have tended to be conservative (which for regulatory purposes is understandable), with the exception of forecasting under sustained drought conditions, which appears to have had comparatively little focus until recently. We note the market may have also benefited from mild weather conditions at the times when thin reserves have been forecast
- In our view it is unlikely that centrally imposed reliability settings, or conventional levels of investment by the private or public sector, will protect the market from large-scale interruptions or unusual events that are inherently unpredictable or (hopefully) rare such as mass industrial action, extreme drought or acts of god such as cyclones or widespread and unusually fierce bushfire events. Future investment is likely to consume less potable water and be less likely to be susceptible to drought
- Generation is only one factor in system security and reliability. The available evidence suggests that power generation itself is the smallest contributor to historic rates of system interruption in the NEM, with distribution networks being the most prevalent source of disruptions
- To date demand side response appears to play a small role in the market and in enhancing reliability

The weight of evidence is that there is little reason to suggest that the NEM will not bring about private sector investment, and in a timely manner. There are risks to future reliability, which we discuss in Section 4, and government intervention in the market is a key risk to private investment.

We close this section by reviewing below in Box 13 the performance of investment in the U.K. market which was the first market to open up to competition. This experience shows the private sector to be more than capable at investing in substantial plant, and maintaining adequate reserve margins—in a fully privatised market—across a 17-year period.

Box 13: Lessons from Other Markets: Private Sector New Investment Behaviour—United Kingdom

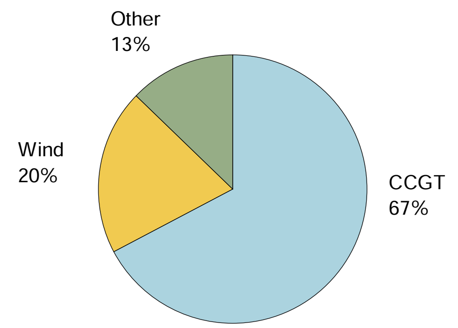
Within the United Kingdom, the electricity supply system of England and Wales commenced profound industry restructuring and liberalisation from 1990, and as such is the oldest market based system available to be studied.

During the period from 1990, the industry has undergone changes in market design (notably the requirements on incumbent generators National Power and Powergen to divest capacity, and the replacement of the wholesale pool market with revised trading arrangements known as NETA), and periodic special rules relating to fuel choices and emissions regimes. Within this framework, generation development has been left entirely as the responsibility of the private sector (with the exception of certain nuclear generation assets). The private sector has favoured investment in gas-fired generation, as shown in Exhibit 18 below.

3.13 Morgan Stanley Conclusions on Private Sector Investment and NEM Reliability to Date (cont'd)

Box 13: Lessons from Other Markets: Private Sector New Investment Behaviour—United Kingdom

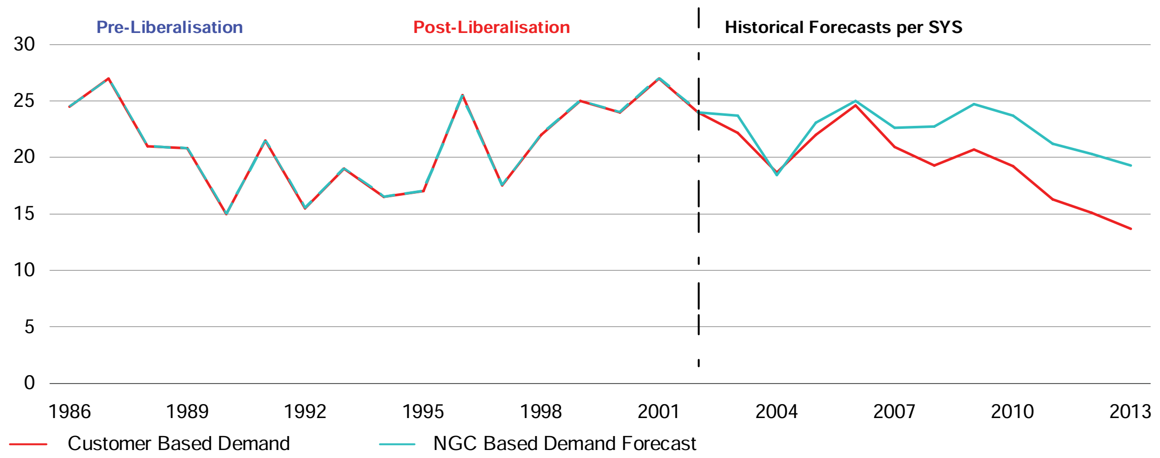
Exhibit 18: U.K. Generation Investment Since 1992
Gross Additions by Type (%)



Source Chart data sourced from National Grid Seven Year Statements available at www.nationalgrid.com/uk

Prior to competition, the Central Electricity Generation Board ("CEGB") targeted reserve levels of 24%. In the decade following competition, reserve levels fluctuated between 16%–26% and mostly in the range 20%–25%. Forecast reserve margins, particularly for more than 2–3 years ahead, tend to underestimate the margin achieved in practice, as plant build decisions tend not to be made this far in advance. This is shown in Exhibit 19 below.

Exhibit 19: U.K. Plant Reserve Margin Since 1986 (1)
%



Sources Chart data sourced from Department of Trade & Industry and National Grid Seven Year Statements available at www.nationalgrid.com/uk

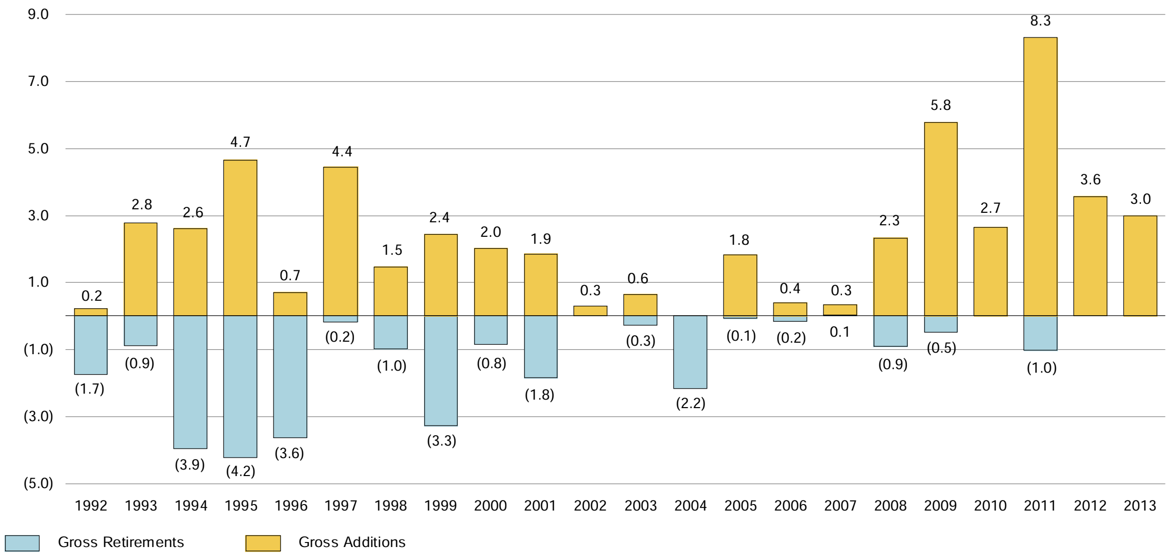
Notes

1. Have applied the "Consents Background". This background includes all existing plant and plant under construction that has obtained regulatory development consent. It does not include all potential plant development projects. From 2001 onwards plant margin is derived from customer based demand forecast and National Grid's own view of future demand growth

3.13 Morgan Stanley Conclusions on Private Sector Investment and NEM Reliability to Date (cont'd)

Considerable generation has been installed and funded by the private sector, over 21GW of capacity in the decade 1990–2000 alone, refer Exhibit 20 below.

Exhibit 20: Actual and Projected Changes in U.K. Generation Capacity Since 1992
Capacity (GW), Year-End December



Source Chart data sourced from National Grid Seven Year Statements available at www.nationalgrid.com/uk

Private Sector Investment: Origin Energy's Quarantine Power Station in South Australia.
Photo courtesy Origin Energy

Origin Energy currently owns and operates the Quarantine Power Station on Torrens Island, north of Adelaide in South Australia, which it developed in 2001–2002 to meet summer peak demand. This gas-fired power station has a capacity of 95MW. In order to meet the growing demand for electricity in the region, Origin has announced it is expanding the capacity of the plant by adding another gas turbine generator to the four already in place at the existing Quarantine Power Station. The new generator will have a nominal capacity of 120MW.

Section 4
New Investment Conditions

4.1 Introduction

This Section 4 describes the key commercial, policy and process conditions required to establish new private sector generation investment in NSW, with the highest degree of confidence.

Clearly investment could occur under the presence of suboptimal conditions and market distortions and has done so in the past, for example, in the presence of retail price caps. However as articulated earlier, the scope of our role required us to identity those conditions likely to maximise the prospect of private sector investment. Investment may still occur under suboptimal conditions, but it may differ from that which would occur under a more ideal environment, the probability and likely efficiency of timely new investment will be lower, and “hoping” for investment in a suboptimal environment is not consistent with simultaneously targeting high reliability and high efficiency.

Sections 4.2 through 4.6 relate largely to commercially-driven conditions for investment, those which if present will enable investment. Subsections 4.7 and 4.8 relate largely to policy-driven investment conditions which, if inappropriate, could frustrate investment.

In each section we have stated our key findings and set out the supporting evidence and analysis.

4.2 Market Need

Key Findings

The private sector will invest in new generation when there is a clear market need reflected in wholesale electricity prices, and/or when the risk management portfolio of a business requires it.

To date, the existence of surplus baseload capacity in the NEM, has meant that there has been limited market need for additional investment in baseload, and this has been reflected in wholesale electricity prices generally below the LRMC of new generation in recent years. In the early years of the NEM, prices in Qld and SA were signalling a need for additional capacity and this was delivered.

Notwithstanding a lack of market need for baseload investment, the NEM has delivered significant new capacity particularly in the form of gas-fired peaking plant.

This investment has been driven by price volatility. Retailers in particular have responded to price volatility by building gas-fired peaking plant.

Due to the long lead times for new baseload power stations, an investor will need to form a view of likely wholesale prices some four to seven years in the future. The NEM does not currently have a liquid forward market for power this far out. However, major energy users have expressed to Morgan Stanley a willingness to partially underwrite new generation with long-term contracts that meet their commercial objectives.

In the absence of liquid long-dated forward markets, participants tend to conduct their own fundamental analysis of supply and demand in order to determine the likely timing of new investment. Default retailers have particularly strong commercial reasons to forecast supply and demand.

While views inevitably vary, most market participants appear to agree that new baseload capacity to supply New South Wales is likely to be economic around the middle of next decade, which will require investment commitments as early as the next one to three years.

4.2.1 Introduction

Private sector investors require a sufficient return from their investments to cover their cost of capital (debt and equity), as they do not have they the ability to subsidise noncommercial investments. The return from an investor in a power station in the NEM is obtained largely from the wholesale electricity market which comprises the spot market and, to the extent the power station provides hedge contracts to energy retailers and other customers, via contract revenues. Revenues can also be earned through the provision of ancillary services such as frequency control.

Private participants will generally not invest in new generation capacity unless they can form a reasonable expectation that the price available in the spot and contract markets will provide a sufficient return on their invested capital.

Clearly market price is the major driver of investment and new investment in generation is less likely to occur if alternative electricity supplies can be procured more cheaply (for example by procuring alternative supplies from other market participants by way of contract). However there are other motivations for considering new investment which can bear upon the final decision, such as:

- Ownership may provide long-term control and optionality over future decision-making that is not fully replicable via contract markets

4.2 Market Need (cont'd)

- Risk aversion, in that the consequences of not investing are sufficiently adverse so as to compel the investment decision regardless of contractual substitutes. Retailers investing in peak generation are a case in point
- The opportunity to create or realise value in other assets, such as existing fuel positions (owned or contracted fuel)
- A desire to invest ahead of competing investments by rival firms and/or to displace potential investments that might otherwise be contemplated
- To support market entry strategies

Clearly each market participant will have its own view on market need, and the first party to invest is likely to have one or more of the highest risk appetite (or highest risk aversion), access to the lowest cost of capital, business synergies (e.g. earlier monetisation of gas reserves) or strategic reasons to invest.

The level of prices required to justify investment in new baseload generation capacity is known as the Long Run Marginal Cost ("LRMC") of new generation. The LRMC is comprised of:

- The direct, avoidable costs of producing energy, such as the cost of fuel and any direct operating costs that would be avoided if the power station had not run (known as the Short Run Marginal Cost, or "SRMC")
- The indirect costs of operating the power station, such as corporate overheads, ongoing maintenance costs and labour
- The depreciation of the capital invested in the power station
- A return on debt and equity invested in the power station, sufficient to compensate the owner for the risk of the power station investment

The LRMC of power station investment required to supply the three default retailer's retail load in New South Wales has been estimated by Frontier Economics [(1)] at between $43 and $52 per MWh. The Frontier analysis is not the only analysis in the market. Other calculations for CCGT and black coal generally put current estimates of LRMC in the $40–$55 range.

4.2.2 Recent Investment Behaviour Has Reflected Market Need

As noted in Section 3, the NEM has historically had a surplus of generation capacity, particularly baseload capacity, and the effective capacity of the NEM has also increased over time due to improved availability performance. The combination of these factors has resulted in wholesale prices which have been below the LRMC of new generation, as incumbent generators have bid their output, on average, at between SRMC and LRMC in order to be dispatched.

Notes
1. Frontier Economics, Energy Costs (prepared for the Independent Pricing and Regulatory Tribunal), March 2007

4.2 Market Need (cont'd)

As noted in Section 3.9 in NSW, and in most regions of the NEM, the average spot price has been below the estimated LRMC of new generation i.e., below the level required to support new generation investment.

In the 2007 year-to-date, average spot prices have for the first time consistently been within the LRMC range. This has been caused by energy constraints arising from the current drought, principally:

- Restrictions in output caused by low water availability to cool baseload power station in Queensland, and to a lesser extent in New South Wales
- Low dam levels in the Snowy Hydro Scheme, which have resulted in Snowy Hydro making additional use of pump storage generators. These pump storage generators take energy from the grid during off-peak times, to pump water back into dams, which is then available for generation in peak times. The effect of this is to increase power demand and prices during off-peak times, resulting in an increase in the average price of energy

It is important to note that investors in power stations will not base their investment decisions on current market prices, but on their *expectation* of market prices when the power station is completed and operating. Accordingly, to the extent that the current high wholesale prices are caused by short-term energy constraints arising from the drought, it is unlikely that investors will respond by making immediate new generation investment, as they will expect prices to revert to more normal levels once drought conditions ease. Notwithstanding that average power prices have generally not been at sufficient levels to support new generation investment, as noted in Section 3, significant new investment in the NEM has been forthcoming.

This new investment has taken place for three key reasons:

- Some of the investment has been directly government-funded (e.g. some of the Queensland investment) or underwritten by long-term contracts with government entities. Unlike private sector investment, government investment is not directly exposed to capital market disciplines, and may not necessarily be made on purely commercial grounds. For example, governments may be prepared to accept subcommercial returns on “state development” grounds
- Some of the investment has been commercial, but has been driven by revenue incentives operating outside the energy revenues derived from the NEM. For example, some gas-fired generation investment has been driven by revenues available under the NSW Government's Greenhouse Gas Abatement Scheme or the Queensland Government's 13% Gas Scheme. Investment in renewable generation has been driven by the Commonwealth's Mandatory Renewable Energy Target. In addition, some investors have used generation as a means of monetising other assets they own, e.g. Origin Energy's investment in its Braemar CCGT station has been driven in part by its ownership of gas reserves in Queensland
- Some of the investment has been commercial, but hasn't been driven directly by energy revenue available via the NEM, but by the risk management benefits available to a party from owning and controlling generation capacity. This is particularly true of open-cycle gas-fired generation development by retailers, who are exposed to the volatility of electricity prices and can substitute ownership of a highly-flexible open-cycle gas plant for certain types of hedging contracts (e.g. caps). To a retailer, the capital cost of building and owning peaking capacity are analogous to the premia they would pay to a generator to write them a cap contract. Examples of such investment include

4.2 Market Need (cont'd)

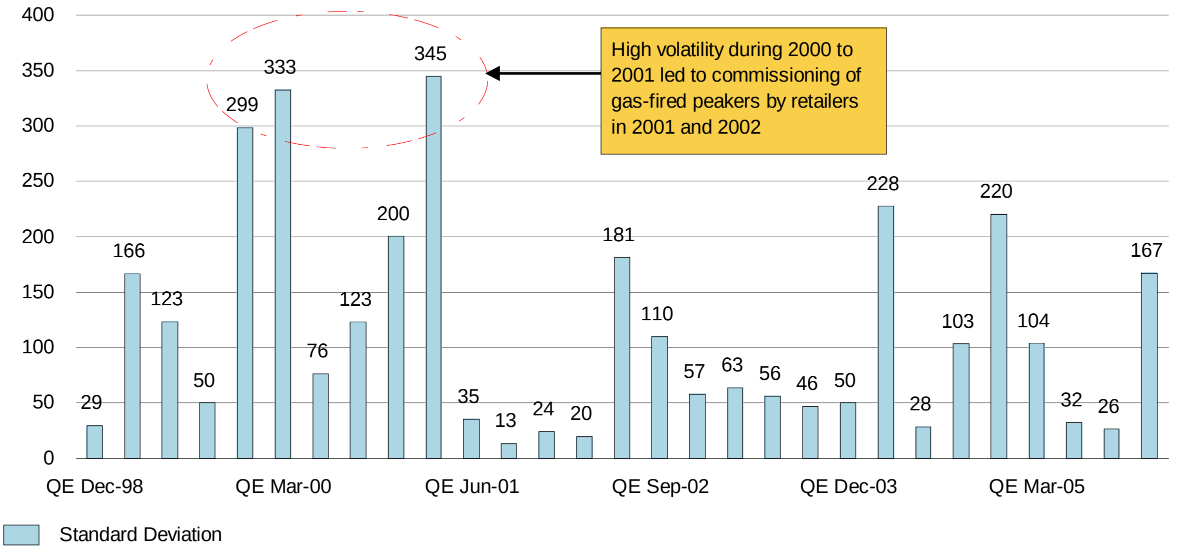
AGL's development of the Hallett and Somerton open-cycle gas plants, and Origin Energy's development of the Quarantine open-cycle gas plant

Development of peaking plant by retailers is a natural market response to wholesale electricity price volatility, rather than average electricity prices. It is not surprising that retailers have led the development of peaking plant. Mass market retailers face the statistical certainty over time that peak days will happen and have the potential to be highly expensive to the exposed retailer if it is not hedged at that time. Generator incentives to build peak are slightly less in that missing a peak revenue period is an opportunity cost, but does not have the same risk of certain loss as faced by an unhedged retailer.

As the charts in Section 3.9 indicated, when the NEM was established, there was significant surplus capacity in baseload generation in most regions. However, the market was relatively "short" of peaking capacity (i.e., flexible, open-cycle gas plants that can operate at short notice to supply peak demand). The lack of flexible peaking plant was reflected in relatively high levels of wholesale price volatility (because the supply-side of the market wasn't able to readily respond to spikes in demand), which created incentives for investment in capacity which allowed the volatility to be most cheaply managed (i.e., open-cycle gas). Retailers, who were most exposed to the volatility of wholesale electricity prices, were the natural investors in these plant.

As an example of market price signals driving investment, the exhibits below show the quarterly volatility in wholesale electricity prices in Victoria and South Australia from 1998 to 2005. As can be seen, significant price volatility, as represented by the standard deviation of wholesale electricity prices, was particularly significant during 2000 and 2001, which led AGL and Origin to invest in peaking plants shortly thereafter.

Exhibit 21: Volatility in Wholesale Electricity Prices in SA
Standard Deviation in Pool Price per Quarter [(1)], Since 1998

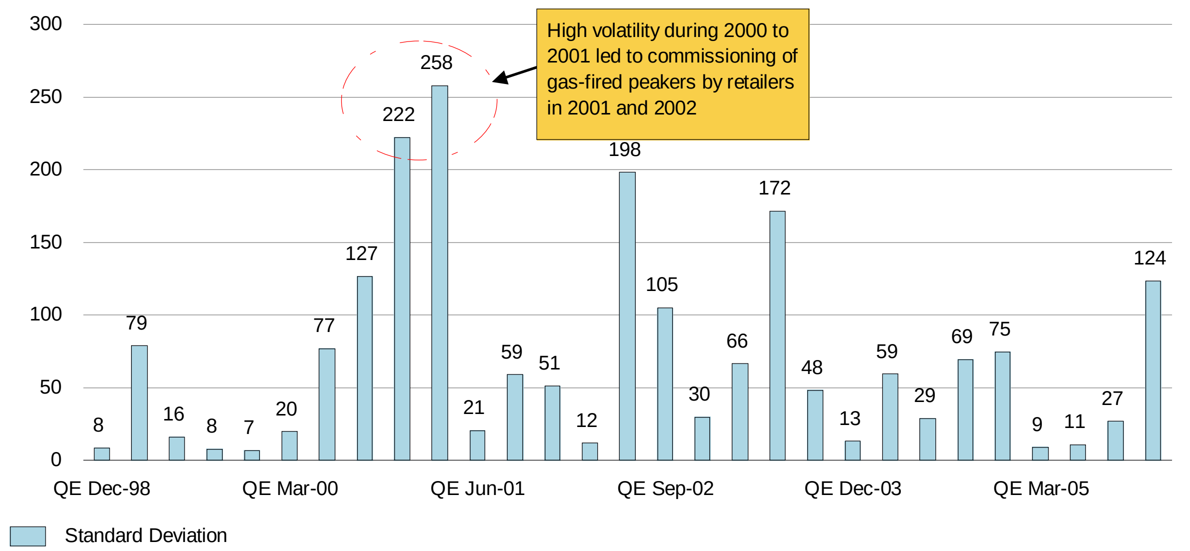


Source NEMMCO, Morgan Stanley analysis

Notes
1. Only 17 days in QE Dec-98

4.2 Market Need (cont'd)

Exhibit 22: Volatility in Wholesale Electricity Prices in VIC
Standard Deviation in Pool Price per Quarter [1], Since 1998



Source NEMMCO, Morgan Stanley analysis

Notes
1. Only 17 days in QE Dec-98

The investment behaviour of retailers in response to the volatility of prices in 2000 and 2001 is a demonstration of the effectiveness of the market's response to price signals.

Submissions to the Owen Inquiry from parties representative of those likely to invest in NSW generally expressed a high degree of confidence that an effective market can provide appropriate signals for required new investment, and is superior to a more centrally planned approach to delivering generation investment:

… it's our belief that a properly functioning, efficient and informed environment it is the market that will respond most efficiently to the energy needs and timing of supply.
– Infrastructure Partnerships Australia

… retailers are generally confident that the National Electricity Market (NEM) can deliver investment of the right type to the right locations in a timely fashion. In the regard, the Association does not consider there to be a need for the government to intervene in the market or directly underwrite new investment in any way … We note that to date wherever price signals have been strong enough in the NEM investment has been delivered; particularly in Victoria, SA and Qld.
– Energy Retailers Association of Australia

Due to the significant uncertainty in forecasting parameters, a centrally planned approach is unlikely to deliver an optimum investment plan. A market based process is likely to be much more efficient in working through the various assumptions and deliver the optimum investment outcome.
– TRUenergy

4.2 Market Need (cont'd)

4.2.3 Determining Future Market Need

Given the long lead times of major baseload power stations, investors will need to form an expectation of likely wholesale power prices around four to seven years in the future.

In commodity markets, an important signal of the market's expectation of future commodity prices are those derived in the forward contracts market. The NEM has an associated forward contracts market. While this market is reasonably liquid over a horizon of around three years, there is limited contract availability and liquidity beyond three years. The effect of the short-term nature of the contracts market is that prospective investors are unable to derive an "objective" market view of the requirement for new generation capacity via long-term traded forward price signals. (1)

In Morgan Stanley's view, the relatively short-term nature of the forward electricity market to date has been in part a function of the market's excess capacity. While excess capacity has existed, and prices have been below LRMC, electricity retailers and large electricity users may have had less incentive to enter into long-term contracts (which would need to be close to LRMC in order to be commercially-attractive to generators) because they have been able to purchase electricity at prices below LRMC on the spot and short-term forward markets.

There are other structural reasons why the NEM may tend towards short-term contracting. Under full retail contestability, mass market customers can churn away from retailers, leaving retailers with excess long-dated supply contracts. Retail tariff caps, periodically reviewed by state-based regulators, may also have played a role, since costs of long-term supply contracts may not have been reflected in future tariff cap reviews.

Under the prevailing environment of FRC this makes larger commercial and industrial customers particularly important sources of long-term contracting. In discussions with major users, there was a clear desire for stable long run supply contracts, and with some generators, a desire for long-term off-take contracts to reduce merchant risk exposure. Both the supply side of the equation (generators) and the buy side (major users) share the same view as to the desirability of certainty provided by long-term contracting—but for whatever reasons, to date there appear to have been relatively few long-term contracts entered into between these different counter parties that did not predate the NEM.

More recently, uncertainties as to future costs under carbon regimes may also have played a role in reducing incentives to long-term contracting, and in very recent times, drought restrictions have clearly played a role.

In the absence of direct long-term forward price signals via contracts, market participants tend to conduct their own analysis of potential future supply and demand conditions, and therefore probable future prices, in order to determine the likely need for further generation investment.

Retailers with default obligations to supply customers have a particular interest in forecasting future supply and demand conditions, because they have a continuing, long-term obligation to supply customers, and can suffer adverse financial and reputational exposure if sufficient generation capacity is not available to supply demand. They use their analysis of supply and demand to determine hedging

Notes

1. Even with a liquid, long-dated forward contract market, it may not actually signal the need for new generation investment via high future contract prices, as market participants may factor in an assumption that new generation investment is made when they price contracts.

4.2 Market Need (cont'd)

strategies, the prices they are willing to pay for hedge contracts, the prices at which they market electricity and ultimately, their willingness to make or underwrite new investment in order to meet any future supply gaps.

4.2.4 Private Sector Views on Market Need

Based on their own fundamental analysis of emerging supply and demand conditions, a number of potential private investors provided the Owen Inquiry with their view of likely future market need for new generation capacity.

Understandably, these views vary, as different investors have different views on likely future demand and supply developments, and different assumptions in relation to future input prices (e.g. fuel and carbon).

However, the general consensus seems to indicate a market need for:

- More immediate investment in peaking/intermediate plant, to be commissioned from around 2011/2012
- More medium-term need for additional baseload plant to be commissioned around the middle of next decade

A number of participants noted that this capacity need not be located in NSW (e.g. it could be located in Queensland, with power transmitted to NSW via an upgraded transmission line). However, unless another region has a persistent fuel cost advantage that overcomes the incremental costs of transmission, or is incentivising investment in that region through State-based policies, it is inevitable that some additional baseload capacity will need to be located in NSW. Transmission is not a complete substitute for generation, and is subject to constraints as noted in Section 3.

A selection of private sector views provided to the Owen Inquiry follow:

New baseload capacity is required in NSW or Qld by 2013/2014. Our current model tends to favour generation at the Queensland end of the network for reliability reasons, but this is a comparatively "soft" preference and the actual location should be driven by economics (such as fuel costs) and certainty of permitting and approval.

– Transfield Services

In summary, we believe baseload investment could be required from as early as 2012, however, there is significant uncertainty in the forecast, and credible cases can be made out to 2015/2016.

– TRUenergy

Origin's modelling suggests baseload discussions revolve around three key dates:

- *Assuming full interconnection and availability of supply from other states, baseload is not required until about 2017*
- *Assuming interconnection cannot be fully relied upon, baseload is not required until about 2015 (it also becomes economic for generators to build baseload around this time)*
- *Demand for swap contracts to meet average demand, is projected to exceed supply from 2014 in NSW*

– Origin Energy

4.2 Market Need (cont'd)

A number of parties, in their submissions to the Owen Inquiry, also had views on the more immediate need for investment in peaking/intermediate capacity:

As the predominance of existing generation capacity installed in NSW is coal-fired, in order to establish an economically efficient mix of generation in the state, additional intermediate and peaking generation is required to meet future demand.

– AGL Energy

Another important observation… is the relative lack of intermediate and peaking plant in NSW… Importantly, the market has very correctly identified this structural fault as evidenced by the $1 billion of capital investments being made by the private sector at the time of writing. The two facilities at Tallawarra (400 MW) and Uranquinty (640 MW) are aimed at restoring the plant mix in the intermediate and peaking asset classes respectively.

– Babcock & Brown Power

4.3 Access to Sustainable Business Models

Key Findings

Private sector participants that invest in generation assets, both in Australia and internationally, have different levels of risk tolerance. The level of risk tolerance is broadly manifested in one of the following business models:

- Fully contracted generation: low risk
- Vertical integration (“gentailers”): low-medium risk
- Merchant generation stand-alone or in a portfolio: medium-high risk

Notwithstanding which of the above models is applicable, each participant will generally seek to build a portfolio of assets that generate a relatively predictable stable stream of revenue and earnings. The contracted generation model has the most predictable revenues since they are fixed under long-term contracts but also the least upside. The merchant generation model will have the least predictable revenue streams as they generally have a portion of their output exposed to the market price of wholesale electricity, which can fluctuate greatly. Merchant generation risks can be diversified by investing across multiple plant, with the diversity of plant securing diversification of risk. The vertically integrated model seeks exposure upstream and downstream to provide stability of earnings across business cycles.

Any firm will have a defined risk tolerance level that inherently requires the business to “hedge” its output, either internally in the case of vertically integrated firms, or externally, to insulate the business’s earnings from potentially volatile movements in wholesale electricity prices. The Australian experience with private sector investment has seen a clear trend towards portfolio generation and vertical integration.

Vertically integrated firms (such as AGL, Origin and TRUenergy) seek a degree of internal hedging risk through the acquisition of both retail customers and owned generation, and are often referred to as “gentailers.” Gentailers have evolved largely from the requirement for large electricity retailers to add owned generation to offset the risk of variable input costs (wholesale electricity prices) being sold at largely a fixed level to customers (regulated price caps or contestable contracts).

While an over-the-counter (“OTC”) market exists and can hedge this risk, owned generation adds an increased degree of flexibility to a portfolio in managing its risk position. Evidence suggests that vertically integrated firms also attract a lower cost of capital and higher credit ratings. There is also evidence of stand-alone generation participants that have traditionally been long generation and short customers, moving to acquire customers to provide some hedge to their long generation positions and a direct sales channel to end consumers. International Power’s acquisition of the Energy Australia retail joint venture portfolio in Victoria and South Australia is an example of this.

Portfolio generators, i.e., firms that own numerous plant that are diversified by location, fuel type, technology and off-take arrangements, is the other model that is most common in the NEM. Portfolio generators have the core business of owning and operating generation assets. The recent float of Babcock & Brown Power is an example of this, while International Power has been structured in this vein for some time. The SOCs in NSW and the generators owned by the Queensland government also have this business model.

4.3 Access to Sustainable Business Models (cont'd)

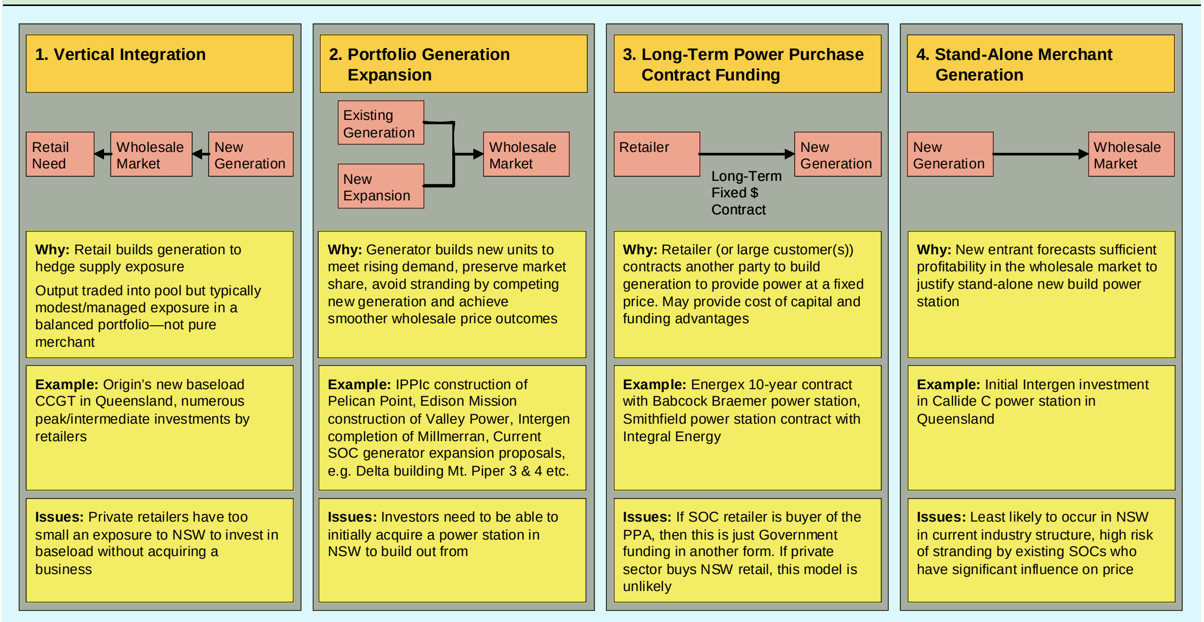
4.3.1 Introduction

Investors will seek a reasonably predictable revenue stream to underpin new investment. Capital providers will provide funds most competitively to firms that have a diversified risk profile by way of either vertical integration, are diversified portfolio generators, or that have significant long-term off-take contracts. In contrast a pure merchant power plant operating in a pool market will exhibit much higher levels of revenue volatility with this risk leading to a higher cost of funding.

There are essentially four potential business models for new investment in the NEM illustrated in Exhibit 23:

- Investment by vertically integrated gentailers
- Investment by portfolio generators that already have existing plant
- Investment in stand-alone plant underwritten by a medium to long-term power purchase agreement ("PPA") with a counterparty, typically a retailer or major industrial consumer
- Investment in stand-alone "merchant risk" plant

Exhibit 23: Business Models for New Generation Divestment



Of all of these different models, 1, 2 and 3 offer different forms of risk diversification from the naked "merchant" NEM risk offered by model 4 which is the least predictable and most risky form of investment. Risk diversification is important in a new investment context, and should be actively facilitated, because a reduced risk profile should in turn lead to a lower cost of capital, and hence lower new entrant prices and earlier entry.

4.3 Access to Sustainable Business Models (cont'd)

Morgan Stanley has examined the key issues and considerations for each model.

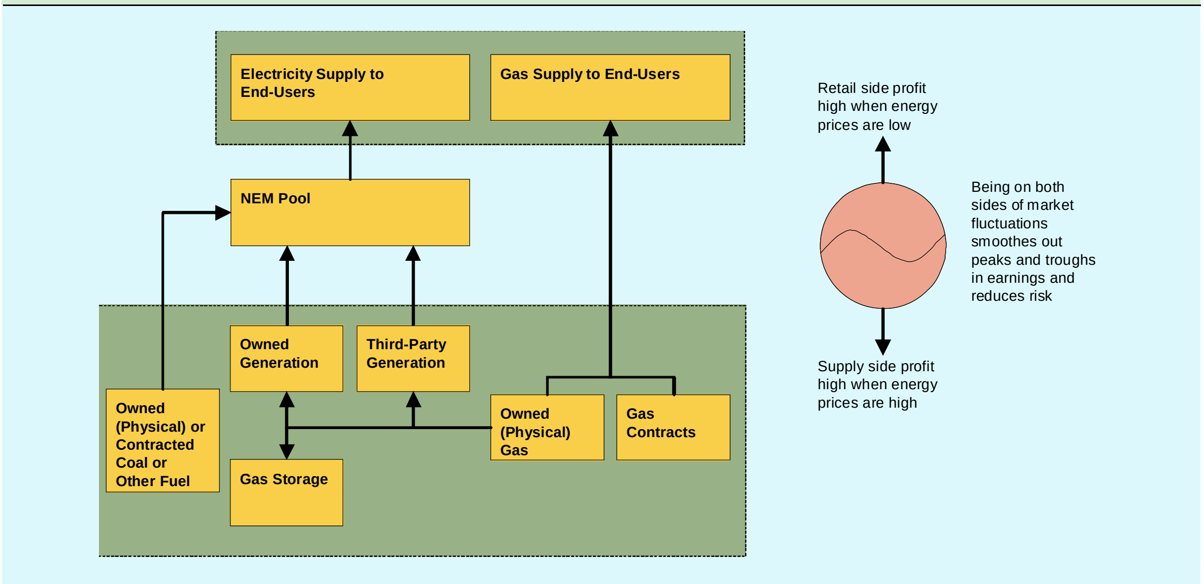
4.3.2. Model 1: Vertical Integration

Domestically and internationally, numerous private sector participants in electricity markets have gravitated towards a vertically integrated business model, i.e., the ownership of both generation and retail customers, or "gentailers." Vertical integration has emerged naturally from market forces at different points in the energy value chain:

- Retailers entering generation: Retailers over are strongly incentivised to secure their supply needs through acquired or constructed generation portfolios. Retailers have sought to mitigate the risk of being undercontracted on the supply side due to factors that are outside their own control, e.g. under-investment in generation or independent generator behaviour limiting the availability of supply of hedge contracts
- Generators entering retail: For generators, direct access to customers provides certainty of off-take, an alternative to selling to counterparties in the wholesale market and underpins investment decisions
- Fuel suppliers entering generation: For owners of fuel resources, such as gas or coal, developing generation provides a means of monetising that resource and bringing value forward in time through the electricity market

The vertically integrated model can be diagrammatically described as per Exhibit 24.

Exhibit 24: Vertically Integrated Business Model
Private Sector



4.3 Access to Sustainable Business Models (cont'd)

AGL noted in its submission that "*nearly all additional generation capacity in the NEM resulting from investment by the private sector, has had some form of downstream support in order to improve revenue certainty.*" Table 11 below is repeated from the AGL submission.

Table 11: AGL Submission on New Generation in the NEM

Project	Technology	Location	Downstream Support
Pelican Point	CCGT	SA	Medium-term contracts with ETSA and AGL
Valley Power	OCGT	Vic	Medium-term contracts with Pulse
Ladbroke Grove	Gas	SA	Origin retail entry in SA and incumbency in Vic
Quarantine	OCGT	SA	Origin retail entry in SA and incumbency in Vic
Playford	Coal	SA	Medium-term contracts with AGL
Somerton	OCGT	Vic	AGL retail incumbency
Hallett	OCGT	SA	AGL retail incumbency
Bogong	Hydro	Vic	AGL retail incumbency
Bairnsdale	OCGT	Vic	Network support agreement with TRU
Laverton	OCGT	Vic	Red Energy retail entry in Vic
Braemar	CCGT	Qld	Long-term contract with Energex

Source AGL Energy's submission to the Owen Inquiry (29 June 2007)

Fundamentally, investment in generation by vertically integrated participants with significant retail exposures is undertaken so as to hedge their risks and ensure direct management control over a component of their overall electricity supplies. This business model can only occur in NSW if the private sector is able to acquire the existing retail businesses to create a material retail exposure to the NEM.

The Energy Retailers Association of Australia [(1)] has stated that *"exposure to volatile pool prices at the wholesale end and fixed prices at the customer end imposes significant risks, with the costs of over contracting in this context generally considered to be lower than being undercontracted. Consequently, the stronger incentive for retailers to limit the risks of high and volatile pool prices compared to generators provides further strong impetus for retailers to ensure sufficient generation is built over time."*

In its submission to the Owen Inquiry, TRUenergy [(2)] emphasised the importance of gaining access to significant retail load to underpin revenue certainty, noting that *"in order to fund significant baseload investment, the private sector needs access to the reliable revenue streams associated with mass market retail load."* In addition it commented that *"access to significant mass market load provides the incentive to ensure investment is delivered in time to ensure security of supply."*

Notes
1. Energy Retailers Association of Australia, Re: Owen Inquiry into Electricity Supply in NSW, 4 July 2007
2. TRUenergy submission to the Owen Inquiry, 29 June 2007

4.3 Access to Sustainable Business Models (cont'd)

KPMG's report to ERIG in 2006, [1] which surveyed the views of energy market investors, concluded that:

"Investors are of the view that, absent government intervention, in ten years the NEM would probably feature:

- *Three to four vertically integrated major retailers*
- *Several niche players in the upstream and downstream sectors"*

This phenomena has prevailed in overseas markets as well. The International Energy Agency noted in 2003 that [2] *"power firms are also responding to the uncertain environment by greater use of contracting, by acquiring retail businesses, and through mergers with natural gas supply businesses."*

Vertical integration has emerged naturally from market forces, both in Australia and international energy markets, as it is a logical step to mitigate market risk and provide access to cheaper cost of capital.

Mitigation of Market Risk

The fundamental advantages of vertical integration, while not always easy to statistically quantify, centres on two key factors:

- Decision-making on hedging can be internalised to a degree, rather than relying on external counterparties (i.e., reduced agency costs). By internalising commercial decision-making the risks of relying on third-parties is lower
- Commercial entities may make no greater returns on average when integrated, but probably make 'normal' returns in a more predictable manner, given the ability to internalise risk, hence reducing risk for the same given level of return. This is consistent with a view that vertically integrated firms can and should attract a lower cost of capital

Moody's recently noted that [3] *"In view of the recent privatisation of retail entities in Queensland, Moody's believes that the acquirers of these businesses will have strong incentives to build generation capacity to support their electricity retail obligations in that state."* This has been given credence by Origin's announcement of the construction of the 630 MW CCGT at Darling Downs, following its acquisition of Sun Retail.

As has been recently evidenced in the NEM, where a convergence of external factors combine to force up wholesale spot and forward electricity prices, retailers that are not vertically integrated have been found to be acutely exposed to financial distress. Examples have included Energy One, Momentum Energy and Jackgreen.

Energy One, a small electricity retailer, suspended the supply of electricity on 22 June 2007. While Energy One was largely insulated through hedges, the extremely high wholesale prices had a significant impact on its cash flow and its future viability as a going concern.

Notes

1. Impediments to investment in Australia's energy market, November 2006
2. © OECD/IEA, 2003, Power generation investment in electricity markets
3. Australian/New Zealand Electricity and Gas 2007 Outlook, May 2007

4.3 Access to Sustainable Business Models (cont'd)

Another small retailer to experience financial difficulty was Jackgreen, which due to the recent high wholesale electricity prices and increase in its load growth has required it to secure additional hedge cover and financial support. It was required to secure additional working capital and funding from it's 20% shareholder, Babcock & Brown.

Drawing on experiences in the adjacent NZ market, AGL's 60% owned NGC experienced difficulties in 2001 with high wholesale prices combined with a lack of hedging. NGC booked abnormal losses for the year to 30 June 2001 of NZ$311.5MM and exited the retailing business. The NGC retail customers were bought by generators.

Risk mitigation is also practiced by generators. International Power recently acquired the balance of its retail joint venture with Energy Australia, which provides International Power with an important route to market for its generation and commercially provides an alternative to only dealing in the wholesale market.

Access to Cheaper Cost of Capital

Cost of capital arguments can not be definitive in the absence of being able to observe how the nonintegrated pieces of integrated firms would trade. Morgan Stanley supports the view that integrated players can achieve reduced costs of capital and a sample of firms is analysed later in this section. We note the following:

- In the Australian context, where retailers have had the opportunity to integrate, they have done so rather than remaining 'pure' retailers. This commercial behaviour reflects a number of factors but is consistent with an expectation of favourable cost of capital consequences. Integration has tended to occur more at the peak-intermediate level, than with baseload generation, as this is where the greatest retail risk exposure has been historically
- Ratings agencies attribute lower risk (and higher ratings, imputing lower debt costs) to integrated retailers compared to stand-alone retailers

KPMG [(1)] noted that based on evidentiary analysis of various investment bank brokers views of the costs of capital that *"a merchant generator's cost of capital is likely to be about 2% higher (or about 25%–35%) than that of a generator with a long-term contract. A vertically integrated players is likely to have a cost of capital somewhere between those two extremes, depending on how well it is vertically integrated."*

Eraring Energy [(2)] noted that *"as a stand-alone generator there is considerable revenue risk inherent in the National Electricity Market. This translates into capital providers requiring a greater return, i.e., a higher cost of capital… By transferring a large retail portfolio to Eraring Energy, this would reduce the revenue risk and reduce the cost of capital."*

Creation of Greater Optionality

Vertical integration can create greater optionality and profit opportunity within a portfolio, which can help produce more stable and predictable profits for a given level of risk. The presence of gas and gas-

Notes
1. Report to ERIG: "Impediments to investment in Australia's energy market—The views of Investors"
2. Eraring Energy Submission to the Owen Inquiry, 29 June 2007

4.3 Access to Sustainable Business Models (cont'd)

fired generation in a vertically integrated business provides an important source of optionality, which is not present in the traditional stand-alone retail model which continues to apply to the NSW SOC retailers. This optionality allows flexible value-driven decisions around whether to sell gas to wholesale or retail customers, store it for later use, or burn it in a power station. Including other fuels (coal or hydro) in the portfolio multiples the choice of options, as does the option to contract/trade in wholesale markets as an alternative to self-sourcing. The spread of vertically integrated businesses across interconnected markets further increases the ability to optimise the portfolio across different regions, and we expect the introduction of an emissions regime will reinforce the benefits of optionality and the ability to arbitrage fuel and emissions costs.

Commercialisation of Upstream Fuel Reserves

Unlike a number of other states in the NEM, NSW has relatively undeveloped gas reserves and as such it lacks the natural dynamic of local gas developers bringing forward generation to commercialise unutilised gas reserves. Coal developers historically, other than in Western Australia, have not forward integrated into power generation, rather have secured demand for their reserves through very long-term contracts with independently owned coal-fired generators.

This dynamic, the absence of owners of local gas reserves forward integrating into power generation, emphasises the importance of opening up both NSW's retail and generation businesses to private sector ownership as the two likely springboards for new development. The lack of a strong direct fuel springboard in NSW, unlike say Queensland, makes it critical for NSW to optimise generation development possibilities by providing the maximum incentives both to vertically integrated firms and generators alike.

Examples of fuel-led development of generation include those shown in Table 12 below.

Table 12: Fuel-Led Generation Development in Australia

Plant	Developer	Details
Darling Downs (QLD) *Under Construction*	Origin Energy	630 MW CCGT commercialising gas from Origin's CSM reserves at Spring Gully and Walloons. Also supports Origins Sun Energy retail load
Spring Gully (QLD) *First Stage Proposed 2008*	Origin Energy	1000 MW coal seam gas-fired Power Station at Spring Gully—the first 500 MW stage completion expected in 2008. Fuel provided from Origin's adjacent Spring Gully Coal Seam Gas (CSG) gas plant
Roma	Origin Energy	74 MW gas plant fuelled by Origin's CSM reserves in Surat Basin
Ladbroke Grove	Origin Energy	80 MW gas plant fuelled by Origin's South Australian onshore gas reserves
Quarantine	Origin Energy	96 MW gas plant fuelled by Origin's Victorian offshore gas reserves
Condamine (QLD) *Proposed for 2009*	QGC/ANZ Infrastructure	150 MW gas-fired plant to be fuelled by coal seam gas produced at QGC's gasfields in the Surat Basin
Bluewater (WA) *Under Construction*	Griffin Coal	208 MW Bluewaters I Baseload Power Station. Coal supplies sourced from Griffin's adjacent coal mines
Daandine (QLD)	Arrow/APA Group	27.4 MW gas-fired power station fed by gas from Arrow's Daandine CSM field. Country Energy off-taker
Mt Isa (QLD) *Under Construction*	APA Group	30 MW gas-fired power station servicing Mt Isa with gas transported on APA's Carpentaria Gas Pipeline
Richmond Valley (NSW) *Under Construction*	APA Group/Metagasco	30 MW gas-fired power station commercialising gas from Metagasco's Casino gas project

4.3 Access to Sustainable Business Models (cont'd)

We summarise in Box 14 below selected experiences with vertical integration in offshore markets.

Box 14: Lessons from Other Markets: Vertical Integration of Retail and Generation

New Zealand

In 1999, the state-owned generator was separated into separate operating companies. At the same time, previous rules preventing vertical integration were lifted, and new legislation was introduced required distribution lines companies to divest either those activities or competitive generation and retail activities.

These retail companies were then acquired by the generators. The overall result was a reorganisation of activities in the sector with integrated generator-retailers emerging. The commercial logic of this result has been borne out over the last 8 years with the vertically integrated generator-retailer model predominating in New Zealand. It has also been entrenched through periods of market stress, where an under-hedged and nonintegrated retailer previously owned majority by AGL incurred considerable economic losses and was ultimately sold to the generation companies.

United Kingdom

The electricity industry in England and Wales was privatised on a vertically disintegrated basis, with generation (other than nuclear) being owned by Powergen and National Power. The Scottish industry remained vertically integrated, in two companies (Scottish Power and Scottish Hydro (later to merge with Southern Electric to form SSE)). New generation capacity in the 1990's was built by independent power developers.

Initially there were long-term contracts in the liberalised U.K. market, new entrant generators sought long-term off-take contracts with retailers or other off-takers of up to 15 years duration. However there has been a general trend in the U.K. to vertical integration, such that vertically integrated generators now supply approximately two-thirds of the market.

IEA [(1)] notes that with respect to the U.K. generators, *"the generating companies that have been able to retain retail customers have been better able to withstand falls in wholesale power price caused by excess capacity."*

There are six vertically integrated utilities in the United Kingdom that are roughly similar in size, controlling approximately 15%–20% of the residential supply market each. Three of these firms are primarily merchant generators and there are no major independent retailers: Centrica; Innogy (RWE parent); EdF; Powergen (parent E.On); Scottish Power (parent Iberdrola); and SSE. In addition there are three merchant generators (International Power, British Energy and Drax), and no major independent retailers.

California

California was the first state in the US to restructure its electricity industry and the power crisis it faced earlier this decade have been well documented. The premise of the restructuring of the Californian energy market was, amongst a plank of other policy and market reforms, the disaggregation of previously vertically integrated utilities. The basis for disaggregation was primarily founded on the principle that vertical integration would provide incumbents with an unacceptable degree of market power.

In California some utilities are reverting back to vertically integrated businesses model.

In a recent paper Robert J. Michaels, a professor in the Department of Economics at California State University, noted [(2)] *"The California's performance has brought a general agreement on the value of requiring transitional contracts between utilities and the owners of divested generation. A transition from integration to unbundling gives rise to new price risks for both generators and retailers because generators sell at the wholesale price while retail rates are usually fixed. In an integrated utility, these cancel out, but a deintegrated system will probably require contracts to allocate the obligations and risks. Such contracts may be difficult to formulate because independent plants can obtain capital more cheaply if their contracts contain commitments for both prices and outputs, while utilities prefer discretion about their economic dispatchability under changing fuel prices and system conditions."*

Notes

1. © OECD/IEA, 2003, Power generation investment in electricity markets
2. R Michaels, Cato Institute: "Vertical Integration & the Restructuring of the US Electricity Industry", 2006

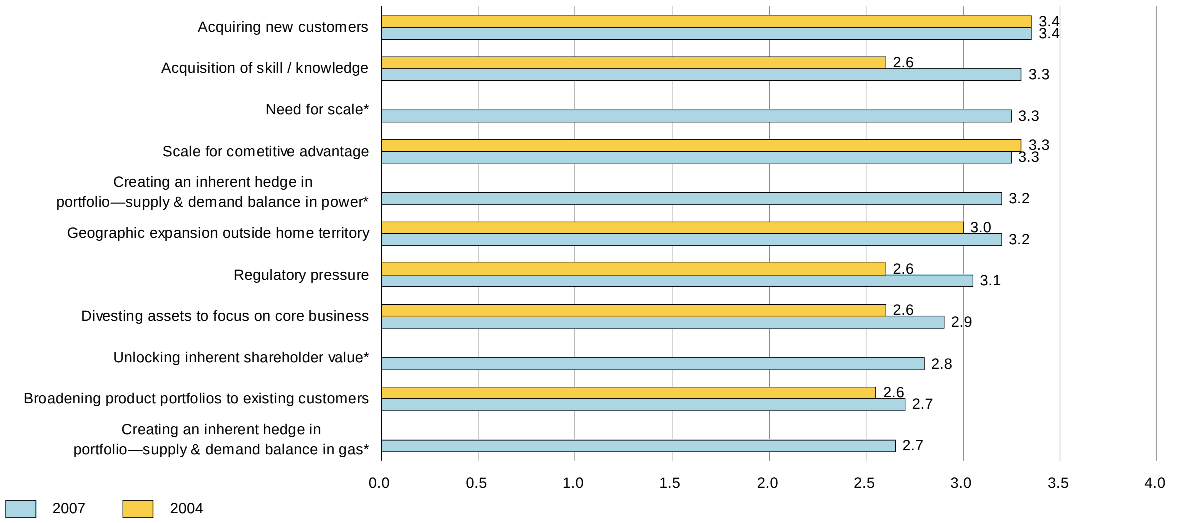
PWC [(1)] has noted that "the quest to build scale, develop a balanced portfolio and extend the customer base is driving M&A activity worldwide," highlighted in the chart below.

Notes

1. PWC, Energy and Efficiency, Utilities Global Survey 2007

4.3 Access to Sustainable Business Models (cont'd)

Exhibit 25: Extract from PWC Global Survey
What Is Driving Your M&A Activity?



Source PricewaterhouseCoopers, Utilities global survey 2007

To our mind, there is no doubt that vertically integrated firms will be a permanent part of the landscape both in Australia and internationally, and this business form will occur spontaneously where participants in markets are free to assemble their desired combination of upstream and downstream assets.

4.3.3. Model 2: Portfolio Generation Expansion

Generators with existing plant and portfolios are likely developers of new merchant plant. Today, most portfolio generators remain in public ownership, with the governments in NSW and Queensland retaining large portfolios of plant.

Continued government ownership of the majority of Australian generation (over 20,000 MW) has limited the development of additional large private sector portfolio generators. Large State-owned portfolio generators in the NEM includes the following:

- In New South Wales, the government-owned Macquarie Generation, (4,600 MW), Delta Electricity (4,200 MW) and Eraring Energy (3,000 MW)
- In Queensland, the government-owned CSEnergy (2,600 MW), Stanwell Corporation (1,600 MW) and Tarong (2,100 MW)
- Snowy Hydro (4,400 MW)

Private sector firms that have developed generation portfolios include: International Power (3,100 MW); Babcock & Brown Power (2,400 MW); InterGen (1,300 MW); and Transfield (990 MW).

4.3 Access to Sustainable Business Models (cont'd)

The impetus for developing a diversified portfolio of generation assets is squarely centred around the ability to commercially optimise the portfolio over time and derisk the overall business. Diversity is spread across:

- Geographical location—Plant spread across different regions of the NEM are not solely exposed to single nodal price volatility that can occur from time to time
- Physical insurance—Operations with multiple plant and hedge contracts to secure revenues. Participant are considerably less exposed to risk where they have sufficient plant that can cover for physical interruptions (scheduled or unscheduled) of other owned plant, and so can continue to service existing hedge contracts without undue risk
- Fuel source arbitrage and optimisation—Generally coal and gas, with multiple plant providing optionality and the ability to dispatch least-cost plant to service hedge contracts. This value will be multiplied in a future emissions trading regime
- Revenue source—Portfolios can include PPAs and other forms of long-term contracts as well as merchant exposure to wholesale spot and forward (contract) electricity prices. Contracted revenues underpin earnings and provide access to cheaper cost of capital, while the business can retain some upside benefit through exposure to pool and opportunistic trading and generating strategies to maximise revenue
- Operational mode—Peak, intermediate and baseload to maximise revenue opportunities
- Drought risk—Diversified/mitigated by diversity of fuel, technology and location
- Transmission risk—The risk of large portions of the portfolio being 'constrained off' reduces as the portfolio diversifies geographically

This business model can only develop in NSW if the private sector is able to acquire the existing generation assets to serve as a platform for new investment on a portfolio basis. There has been some evidence in Queensland of the private sector seeking to build a generation portfolio alongside the SOCs, however this activity has largely stalled with Origin's recent Braemar development occurring in the context of a vertically integrated firm with upstream (gas) and downstream (retail) positions.

In discussions with Morgan Stanley, International Power (which is the largest private sector portfolio generator in Australia) indicated that its preference would be for full government privatisation of generation and retail with a government commitment not to build further generation. Privatisation would provide a better base for subsequent generation development through purchase of part of the existing generation stock and a higher appetite for merchant risk exposure. In the absence of privatisation of generation, International Power indicated that its preferred investment model would be to seek off-take (PPA) agreements to underwrite risk.

Transfield Services' submission to the Owen Inquiry stated *"Privatisation of existing assets is not a prerequisite to private investment in new assets, but risks can be significantly reduced if there can be some sharing of portfolio benefits with existing generators."*

In BBP's prospectus it stated "BBP's investment strategy is to grow security holder wealth through pro active management of the initial portfolio and the construction and acquisition of additional power generation assets and associated businesses. Benefits from diversification will be sought across the investment portfolio." Recently BBP announced its investment in the merchant Uranquinty Power

4.3 Access to Sustainable Business Models (cont'd)

Station and stated "The project, once operational is expected to meet BBP's investment criteria in terms of value and yield accretion and is in line with BBP's strategy of maintaining a diversified revenue mix."

In discussions with Morgan Stanley, InterGen (to date the only private developer of greenfield merchant baseload plant) indicated that a preferred development path would be to build new generation that complemented an existing portfolio. InterGen was comfortable with merchant exposure in principle and saw a portfolio of complementary merchant plant (baseload, intermediate and peak) with some fuel diversity as forming the ideal portfolio.

Motivation for New Development by Portfolio Generators

Motivations for new development have been discussed in Section 4.1. From a pure generator perspective (assuming no retail hedge) development will be driven by:

- Price factors, primarily the outlook in the wholesale electricity (contract and pool) markets. This may include siting new plants to take advantage of locational signals driven by emerging transmission constraints
- The opportunity to leverage existing fuel positions
- The ability to capitalise on brownfield development options, whereby new development costs are reduced due to existing infrastructure
- The potential to bring in new plant that has a competitive SRMC and LRMC and displace other plant in the bid stack. This motivation differentiates retail and generator-led investment, since a vertically integrated retailer would not wish to share the favourable economics of new plant with third-parties, nor appear to have strong incentives to install plant that might dampen volatility in the market
- The ability to reduce the prevailing risk in the portfolio by building new plant and creating greater internalised physical insurance. When one unit goes down, the portfolio generator with multiple plant is more likely to have available units that can dispatch and avoid the generator being exposed to high prices but being unable to dispatch and generate to meet its hedge book
- The incentive to progressively add new capacity in a controlled manner over time to attempt to achieve stable wholesale electricity market outcomes, and avoid displacement or wholesale price dips that may occur due to the construction of rival plant (particularly if the rival plant is large in size)

The changing commercial dynamics and improved risk profile gained through a development of a portfolio of plant is illustrated in Table 13 below. This is illustrative only and is not intended to represent the portfolio of any actual generation company, but rather some of the commercial benefits gained by growing a diverse portfolio of plant from one unit to multiple units.

4.3 Access to Sustainable Business Models (cont'd)

Table 13: Illustrative Portfolio Generation Diversification Benefits

Growing Portfolio of Generation Leads to Enhanced Commercial Position and Decreased Risk Profile

	Single Region	Single Region	Single Region	Single Region	New/Other Region
Number and Location of Units/ Plant in a NEM Portfolio	1 Single Region	2 Single Region	3 Single Region	4 Single Region	5 New/Other Region
Fuel/Role	Coal/Base	Coal/Base	Gas/Intermediate	Gas/Distillate/Peak	Any
Revenue Risk/ Volatility	Wholesale market, single region, single unit exposure	Wholesale market, single region	Wholesale market, single region, more predictability/ presence through the merit order	Wholesale market, single region, more predictability across range of market conditions/ merit order	Wholesale market, multiregion, more predictability across range of market conditions
Contracting Level and Flexibility	Single unit, limited by planned and unplanned outage risks and technical capacities of station	Two unit provides lesser outage risks in higher contracting	Greater flexibility and reduced outage risks to support higher contracting	Greater flexibility and reduced outage risks, plant diversity to support higher contracting	Stronger ability to offer firm interregional contracting with less risk
Market Presence/ Influence	Smaller	Small	Growing	Growing	Multiregion
Ability to Arbitrage Fuel and Emission Position vs. Electricity Market	Low	Low	Medium	Significant	High
Physical/Outage Risk Insurance	Higher risk—procure insurance from third party generators	2 unit/plant operation provides self-insurance	3 unit/plant operation greater self-insurance and responsiveness	4 unit/plant operation even greater self-insurance and responsiveness	Portfolio operation for greater self-insurance and responsiveness
Drought Risk Exposure	Higher (if subject to water restrictions)	Depends co- or separate location of second plant	Lower (than 1–2 unit)	Lower (than 3 unit)	Lower (than 4 unit)
Transmission Constraint Risk	Exposed to intraregional and interregional risk	Depends on co- or separate location of second plant	Lower intraregional constraint exposure (than 1–2 unit)	Lower intraregional constraint (than 3 unit)	Low (plant located other side of interregional constraints)
Credit Risk	Higher	Reducing (relative to 1 unit)	Reducing (relative to 2 unit)	Reducing (relative to 3 unit)	Reducing (relative to 4 unit)

Private Sector Portfolio Generators

Private sector participants that own portfolios of generation in the NEM are outlined in Table 14 below.

4.3 Access to Sustainable Business Models (cont'd)

Table 14: Privately-Owned Merchant Portfolio Generators in Australia

Merchant Portfolio Generators in Australia [1]

Parent	Plants	Location (MW)		Operation Mode (MW)		Revenue Source (MW)		Fuel (MW)	
International Power	9	South Australia	890	Baseload	2,712	Merchant	2,371	Coal	2,169
		Victoria	2,169	Peaking	405	PPA	746	Gas	902
		Western Australia	58					Other	46
Babcock & Brown Power	6	New South Wales	150	Baseload	904	Merchant	770	Coal	920
		Queensland	530	Intermediate	627	PPA	1,604	Gas	1,454
		South Australia	770	Peaking	843				
		Victoria	700						
		Western Australia	224						
InterGen	2	Queensland	1,310	Baseload	1,310	Merchant	1,310	Coal	1,310
Transfield	5	Queensland	400	Base	553	Merchant	297	Coal	477
		Victoria	297	Intermediate	180	PPA	695	Gas	515
		Western Australia	295	Peaking	260				

Notes

1. Equity MW shown

Examples of private sector development of (nonwind) generation within a larger, nonvertically integrated generation portfolio include those shown in Table 15 below.

As noted earlier in Sections 3 and 4.1, the NEM has generally been well supplied with baseload generation and retailers were strongly motivated to build the required peaking generation earlier this decade. When taking these factor into consideration, combined with the prevalence of government ownership in the sector, it is to be expected that there are fewer examples of new generation development led by privately-owned portfolio generators. It is noteworthy though that portfolio generators have strong operating competencies, and the only example of private sector baseload coal merchant plant development is found in this grouping. Moreover, technological advancement, particularly in coal, in a future emissions regime, may be more likely to come from portfolio generators with deeper technical and engineering capabilities.

Table 15: Private Sector Portfolio Development of Merchant Plant in the NEM

Generation Portfolio Development in the NEM [1]

Year	Plant	Developer	Detail
2009	Uranquinty (NSW)	Babcock & Brown Power	640 MW/Natural Gas
2002	Millmerran (QLD)	InterGen	852 MW/Black Coal
2002	Valley Power (VIC)	Edison Mission	300 MW/Natural Gas
2000	Pelican Point (SA)	International Power	478 MW/Natural Gas
1990s	Hazelwood Refurbishment	International Power	1600 MW/Brown Coal

Notes

1. Excludes plant built by private sector under PPA arrangements

Public Sector Portfolio Generators

As government in Australia remains such a significant owner of generation assets it is worthwhile considering the current portfolios and the development opportunities that these state-owned portfolio

4.3 Access to Sustainable Business Models (cont'd)

generators have and may develop. While the private sector often has reservations about the commerciality of investment decisions of state-owned entities, the past investment behaviour of the Queensland and NSW generators shows the state-owned portfolio generators to be more active developers of generation than state-owned retailers. The portfolios of the current state-owned generators are set out in Table 16 below; excluding wind and non-scheduled generation.

Table 16: State-Owned Portfolio Generators in the NEM

Entity	Government Owner	Plants
Delta Electricity	NSW	Mt Piper, 2 x 660 MW, Coal Vales Point, 2 x 660 MW, Coal Wallerawong, 2 x 500 MW, Coal Munmorah, 2 x 300 MW, Coal
Eraring Energy	NSW	Eraring, 4 x 640 MW, Coal Shoalhaven, 240 MW, Pump hydro Hume, 29 MW, Hydro
Macquarie Generation	NSW	Bayswater, 4 x 640 MW, Coal Lidell, 4 x 500 MW, Coal Hunter Valley GT, 2 x 25 MW, Gas/Oil
CSEnergy	Qld	Callide B, 2 x 350 MW, Coal Callide C, 2 x 450 MW, Coal(1) Kogan Creek, 1 x 750 MW, Coal Swanbank B, 4 x 125 MW, Coal Swanbank E, 385 MW, Gas
Stanwell Corporation	Qld	Stanwell, 4 x 350 MW, Coal Kareeya, 80 MW, Hydro Barron Gorge, 60 MW, Hydro Mackay GT, 34 MW, Gas/Oil
Tarong Energy	Qld	Tarong, 4 x 350 MW, Coal Tarong North, 1 x 450 MW, Coal (1) Wivenhoe, 2 x 250 MW, Pump hydro
Snowy Hydro	NSW VIC Commonwealth	Snowy Hydro Scheme, 3,756 MW, Hydro Laverton, 320 MW, Gas Valley Power, 300 MW, Gas

Notes

1. Owned via a joint venture with the private sector

It can quickly be seen that only International Power is of comparable size to the largest of the State-owned generators, with the State-owned generators generally as large or larger than their private sector comparables.

State-owned generators have been active developers of plant in Queensland in the past. In the future, the NSW generators have proposed a number of potential power developments. These are highlighted in Table 17 below.

4.3 Access to Sustainable Business Models (cont'd)

Table 17: Examples of Public Sector Portfolio Development in the NEM

Year	Plant	Developer	Detail
Commissioned			
2001	Callide C	CS Energy/InterGen (1)	2 x 450 MW, Coal
2002	Tarong North	Tarong Energy/TEPCO/Mitsui (1)	450 MW, Coal
2002	Swanbank E	CS Energy	385 MW, Gas
2006	Laverton North	Snowy Hydro	320 MW, Gas
Under Construction			
2007	Kogan Creek	CS Energy	750 MW, Coal
2009–2010	Munmorah Gas Turbine	Delta Electricity	660 MW, Gas
Proposed			
	Bamarang	Delta Electricity	Gas
	Marulan	Delta Electricity	Gas
	Mount Piper Extension	Delta Electricity	1500 MW, Coal
	Tomago	Macquarie Generation	Gas

Notes
1. Developed via a joint venture with the private sector

Future Market Composition

It is unlikely all generation in any market will end up wholly in vertically integrated firms, although this is close to the case in the New Zealand market. The U.K. market comprises a mix of vertically integrated firms and portfolio generators, and we believe that portfolio generation is a long-term survivable business model in the Australian market which is likely to grow in importance over time provided that governments in NSW and Queensland make more of their generation assets available to the private sector over time. Ultimately all firms may have a mix of generation and retail interests. Some of these are likely to be mass market retailers with financial motivations to invest in generation, while others are likely to be primarily portfolio generators with some retail hedge and as a direct channel to market.

Our discussions with generation-focused market participants have indicated they would be far more likely to invest in new generation in NSW where they were able to build out from an acquisition of an existing business, which is perceived to be a far less risky business model than building a greenfield plant in competition with the existing SOC generators in their current form. It should also be noted that of the generation proposals currently being developed by NSW SOCs, most are being put forward by the SOC generators. All baseload generation proposals are being made by the SOC portfolio generators.

4.3.4. Model 3: Long-Term Power Purchase Contract Funding

PPAs with government retailers (Model 3 where the government retailer is the off-taker) are favoured by some generators, as they see it as a means of getting a favourable risk allocation and a creditworthy counterparty. However, such a PPA results in government retailers funding and controlling timing of new plant—this is not "private sector investment".

The retailer PPA model alone is unlikely to underwrite investment in baseload plant due to a number of factors:

4.3 Access to Sustainable Business Models (cont'd)

- Retailers cannot be sure that PPA costs will be factored into tariffs where those tariffs are capped by regulators
- In a market that is fully contestable retailers will, over time, become less interested in entering into long-term PPAs given the ability of consumers to switch retail suppliers
- Any one PPA is unlikely to be of sufficient scale to provide the baseload proponent with enough off-take to meaningfully underwrite the investment thesis
- Long-term PPAs are inherently complex and difficult to negotiate on a bilateral basis due to the difference in views on future prices between the generator and the off-taker

The vast majority of the feedback from the private sector has been that it requires direct access to retail load as a condition for baseload investment. There is little evidence to suggest private sector retailers have appetite to underwrite plant other than renewable energy plant which would simply not be built without a PPA. As Table 18 below shows, all plant built in the NEM under PPAs (excluding cogeneration plant embedded in industry processes) since the commencement of the NEM has been built where a government retailer (not private sector retailer) has been the counterparty. (The only exception is the Ecogen Master Hedge Agreement, however this was not a new build and was put in place at the time of the acquisition of this plant by TXU and AES during the Victorian privatisations in an environment where cross-ownership rules may have affected the structuring of this transaction). This suggests PPA-led development has emerged due to government funding or other reasons rather than for commercial reasons alone.

Table 18: Retail PPAs with Generators in the NEM
Excluding Embedded Generators

Retailer	Generator	Detail
Energy Australia (Government-Owned)	Redbank—135 MW (NSW)	30-year PPA covering 90% of Redbank's capacity
Energex (Government-Owned)	Braemar—455 MW (QLD)	10-year cap contract, including provision of GECs
Country Energy (Government-Owned)	Daandine—27 MW (QLD)	Long-term PPA
TRUenergy	Ecogen—966 MW (Vic)	20-year Master Hedge Agreement

4.3.5. Model 4: Stand-Alone Merchant Generation

Relatively few parties appear willing to take a pure merchant exposure on a stand-alone power station investment. Not surprisingly, this form of investment has been relatively rare in the NEM. The only example is Intergen's initial Australian investment in Callide C. This is not a strong example as it was followed shortly thereafter by Intergen's Millmerran plant, thus creating a portfolio position for Intergen, and creating the portfolio generator business model described as Model 2 above.

In particular, where a new investor develops a pure merchant plant with a small market share, where the rest of the sector is controlled by one shareholder as currently occurs in NSW, the returns experienced by the new investor could be perceived to be significantly influenced by factors outside its control and outside the normal operations of the market.

The near universal view of the private sector has been that it is very unlikely to invest in stand-alone baseload generation in NSW in the current industry structure unless that investment was underwritten by contract.

4.3 Access to Sustainable Business Models (cont'd)

4.3.6. Rating and Cost of Capital Considerations

From discussions with credit rating agencies, there has been almost unanimous feedback on the benefits of vertical integration on the financial wellbeing of energy market participants, manifesting in higher credit ratings for vertically integrated companies than stand-alone generators and retailers. Typically speaking, ratings agencies will categorise unregulated utilities into high, medium and low risk groupings.

Examples of "high risk" unregulated businesses include:

- Merchant power generation in highly competitive markets
- Energy trading and marketing that is speculative or market-making in nature
- Investments in unregulated international power assets in unfamiliar markets
- Investments outside core area of industry expertise, including telecommunications, oil and gas exploration and production, and real estate development

Examples of "medium risk" unregulated businesses include:

- Merchant power generation in markets with competition limited by large market shares or, geographic isolation; low cost generation and/or control of production and transmission infrastructure also helpful
- Affiliated generation and supply businesses that sell primarily under contract to regulated utility market area
- Energy trading and marketing that is strictly limited to trading around utility physical generation assets
- Operation of coal mines or gas pipelines that are closely integrated with utility generation business

Examples of "low risk" unregulated businesses include:

- Unregulated electricity generation sold under long-term contract to creditworthy counterparties that assume all risk of fluctuation in market prices of fuel and electricity
- Unregulated electricity generation that is very well insulated from competition because of utility's high market share and/or tight control of key infrastructure assets that are needed to generate or deliver electricity
- Contractual arrangements to manage customers' fuel and electricity needs, under which customers retain all risk of fluctuation in market prices

As business risk increases, entities generally need stronger financial metrics to merit a given rating. Morgan Stanley believes that:

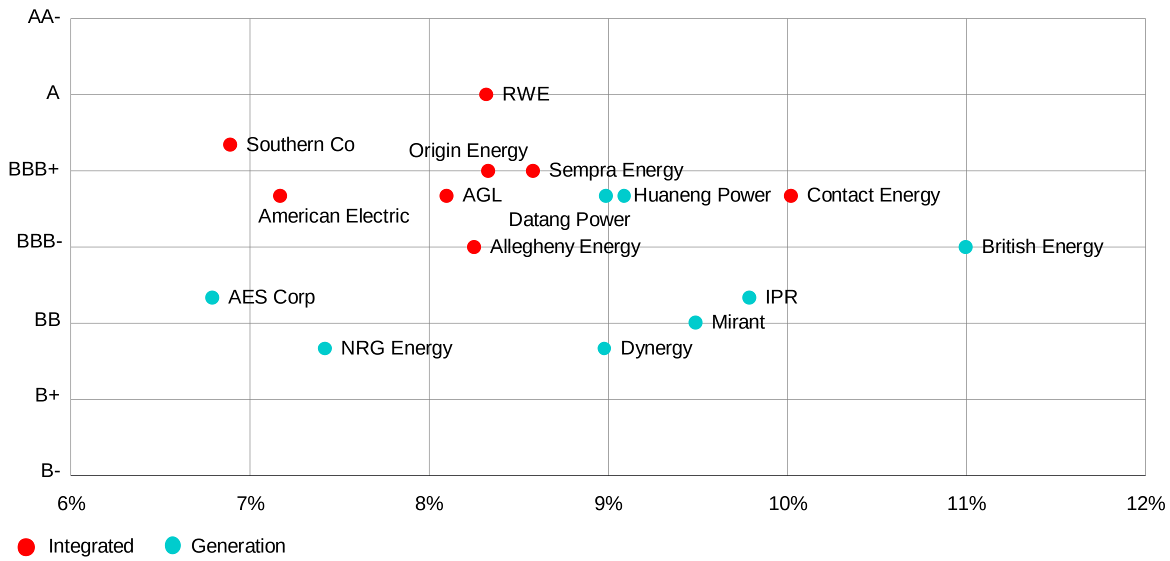
- A stand-alone merchant power generator (not part of a portfolio) is less likely to receive an investment grade rating if operational and other risks (e.g. financial) are not appropriately addressed
- Portfolio generators benefit from risk reduction via physical insurance and diversity across merit order and therefore greater surety of dispatch
- Vertically integrated firms are seen to naturally benefit from risk mitigation from internal hedging

4.3 Access to Sustainable Business Models (cont'd)

In Australia there are limited examples of "pure play" generation or generation focused companies from which to calculate a cost of capital. However there is evidence to support the arguments that the cost of capital or required rates of return are dependent on the business model of the entity and the nature of the generation asset or portfolio. Well capitalised investment grade entities with captive generation fleets, or who are vertically integrated, will have a different cost of capital to purely contracted generators or stand-alone merchant players.

The exhibit below highlights the difference in costs of capital and credit ratings of vertically integrated utilities versus portfolio generators. Despite a few outliers, the analysis demonstrates that firms that are vertically integrated enjoy a better credit rating and lower cost of capital than portfolio generators.

Exhibit 26: Vertically Integrated Utilities vs. Portfolio Generation [(1)]
Weighted-Average Cost of Capital (%) (Horizontal X-Axis) vs. Standard & Poors Credit Rating [(2)]



Source Standard & Poors data, Bloomberg data

Notes
1. Vertically integrated utilities includes companies with both electricity generation and retail businesses only
2. WACC sourced from Blooming estimates

4.4 Access to Fuel and Other Inputs

Key Findings

Before investing in a power generation development, potential investors will seek to manage their exposure to the cost and availability of fuel by contracting for a (firm) fuel supply and assessing the impact of fuel price changes on the economics of their power station.

New South Wales has extensive coal reserves and potential generation investors do not appear to have any concerns regarding availability of coal supply for new power stations. However, investors do perceive significant risks from carbon policy uncertainty—this issue is dealt with more fully in Section 4.7.

New South Wales has less extensive developed and commercialised indigenous gas reserves, and potential investors have raised some concerns about the availability of gas for large-scale baseload power generation. Major energy users have raised concerns about the impact of expanding gas-fired generation on the availability of gas for industrial uses.

However, market participants have generally expressed confidence that adequate new gas supplies will be developed to supply gas-fired baseload generation in NSW in the medium-term. We note that this view has been confirmed by Wood Mackenzie, who was engaged by the Owen Inquiry to report on the availability and cost of gas for NSW baseload generation.

Power station investors' ability to mitigate the price risk associated with fuel supplies relies, in part, on their ability to pass-through market-wide fuel price changes to their customers. In the case of electricity generation, this relies on wholesale, and ultimately, retail electricity prices being determined in a well-functioning market free from inappropriate price regulation. If price regulation impedes power station investors from passing-through market-wide movements in fuel prices, investors' ability to manage fuel price risk is reduced, which decreases their appetite for power station investment. It may also prevent the entry of new and competing fuel supplies.

Fuel-on-fuel price competition (e.g. gas vs. coal) is an important mechanism by which fuel price risk for power station developers is reduced. Governments should therefore not seek to prohibit certain fuel sources being used for power generation, but should manage any externality costs of certain fuel sources (e.g. carbon emissions) via market-based instruments, which would allow environmental outcomes to be achieved while not comprising fuel-on-fuel competition.

4.4.1 Introduction

Fuel is critical input to most forms of power generation, and is a key determinant of the economics of a power generation investment. For example, the short-run marginal cost ("SRMC"), which heavily influences the likelihood of dispatch of a power station, is highly dependent on the cost of fuel consumed in power generation. Potential power station investors are therefore highly focused on:

- Fuel being available to run a power station at the times they need to run it
- The cost of fuel being competitive with other power stations

To manage their exposure to fuel availability and price risk, power station developers will typically take a number of actions during the project development process to maximise the certainty of fuel access, including

4.4 Access to Fuel and Other Inputs (cont'd)

- Developing power stations in geographic proximity to fuel sources (e.g. adjacent to coal mines, or in close proximity to a gas transmission pipeline)
- Entering into long-term fuel supply contracts with a coal mine owner or upstream gas owner
- In some cases, acquiring fuel sources themselves to avoid the risks of contracting

While there are a large range of technologies available for power generation, the most likely fuel sources for large-scale baseload generation to meet NSW's emerging generation investment needs are coal and gas. Terms of Reference 2 and 3 of the Owen Inquiry cover technology choices extensively, and Morgan Stanley's scope does not cover this same ground. However, it is necessary for us to consider likely investor perceptions of fuel availability and price risk in the context of conditions for private investment in generation.

4.4.2 Coal Availability

New South Wales has abundant coal resources. The New South Wales Department of Primary Industries estimates recoverable coal reserves of in excess of 10Bn tonnes. (1) This is equivalent to almost 300 years worth of New South Wales domestic coal consumption. (2)

New South Wales has a long history of production of electricity from coal, which reflects its comparative advantage in coal production, relative to other fuels such as gas. Consequently, New South Wales has developed a large knowledge and skills base in coal mining, coal-fired power station development and operations, which positions it well to develop further coal-fired generation.

New South Wales' legacy of coal-fired power generation provides additional benefits for the development of further coal-fired technology. As the NSW Minerals Council pointed out in its submission to the Owen Inquiry: *NSW's existing [transmission] infrastructure network is located close to the coal resource which means further investment in these areas will be cost-effective and undertaken in a timely manner.*

While parties which Morgan Stanley met with during the Owen Inquiry process had some concerns about coal as a fuel for power generation, principally relating to the risks of investing in a more carbon-intensive generation technology in advance of a carbon trading scheme being finalised, no party raised lack of coal availability as a potential impediment to investment in generation.

4.4.3 Gas Availability

New South Wales has less extensive developed and commercialised indigenous gas reserves, and potential investors have raised some concerns about the current availability and price of gas for large-scale baseload power generation. In addition to small scale coal seam methane sources, NSW is currently dependent on gas supply from two key sources—Gippsland Basin gas from Victoria, via the Eastern Gas Pipeline, and Moomba gas from South Australia via the Moomba-Sydney Pipeline.

Notes
1. New South Wales Department of Primary Industries website, www.dpi.nsw.gov.au. Accessed 9 August 2007
2. Based on ABARE's estimate of domestic coal consumption in NSW of 34.3MM tonnes in 2005–2006

4.4 Access to Fuel and Other Inputs (cont'd)

Morgan Stanley is not in a position to advise on the likely future developments in gas exploration and production, however, we note that the Inquiry commissioned Wood Mackenzie to prepare a report into the availability and cost of gas for NSW baseload generation. This report concludes that

- There is a reasonable expectation that there are sufficient gas supply resources to support long-term gas-fired generation capacity additions in NSW, with higher gas prices expected to support further exploration and development of gas resources in Eastern Australia
- Additional pipeline capacity will be required to meet the growing gas demand in NSW

Submissions to the inquiry, and Morgan Stanley's discussions with market participants, have tended to reinforce the expectation that additional gas supplies will be developed to support new gas-fired generation investment, should this prove economic.

In Morgan Stanley's view, factors that will influence the supply of gas to the NSW electricity market will include:

- Market price for gas
- Development of transmission infrastructure
- Availability of gas from upstream producers and gas wholesalers

4.4.4 Market Price for Gas

Parties will be incentivised to explore for new gas reserves, and bring them into production, if they are confident the price they receive for their gas compensates them for the capital and risk associated with exploration and production.

Development of new gas-fired power generation, particularly baseload generation, is likely to create substantial additional demand for gas in NSW, which may create upward pressure on wholesale gas prices. This upward pressure should result in the appropriate commercial incentives for gas producers to expand their production to meet market demand, and to bring more marginal gas reserves into production. Wood Mackenzie has further considered potential future gas price scenarios in its report to the Owen Inquiry.

In the event that market prices are, for whatever reason, prevented from responding to increases in demand, the commercial incentive for new fuel sources to be developed could be muted.

One such factor that can prevent market prices responding is inappropriate price regulation. Such regulation may not necessarily occur directly at the wholesale gas price level—inappropriate price regulation at other levels of the energy value chain can also impact wholesale gas prices.

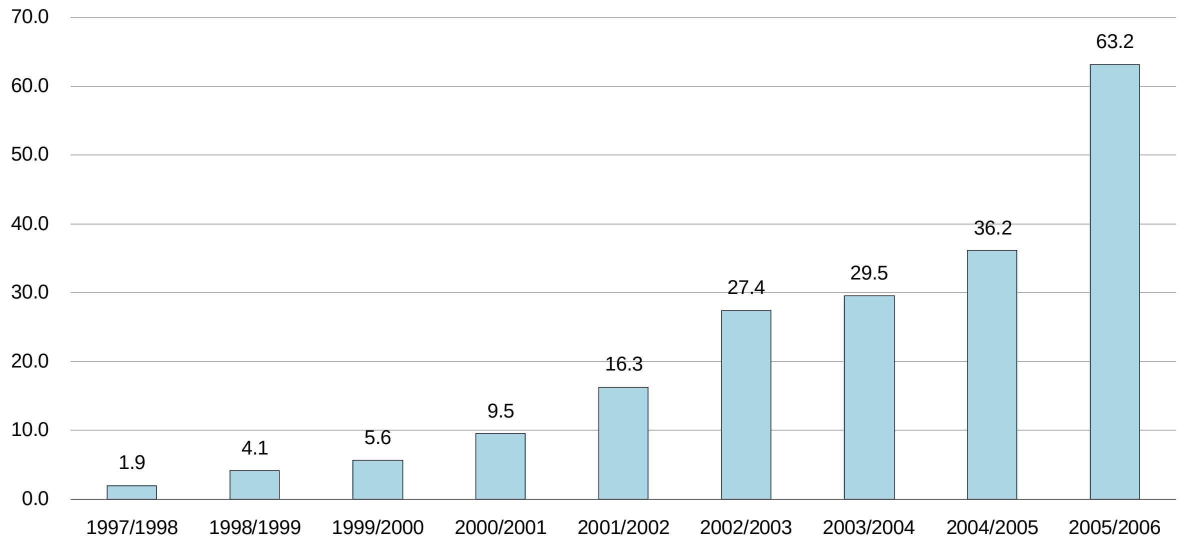
For example, retail tariffs which cap the level of revenue an electricity retailer can recover from its customers, can discourage the retailer from investing in new power generation if the retail tariffs don't allow the retailer, or the market more broadly, to recover the full costs of new investment. This can have flow on effects to gas demand, in that power generation developers will not be seeking new gas supplies, which in turn impacts on the revenue available to gas producers to develop new supply sources. We further discuss the impacts of inappropriate retail price regulation in Section 4.8 of this report.

4.4 Access to Fuel and Other Inputs (cont'd)

Some governments have chosen to introduce an additional price signal to further encourage gas exploration and production. For example, the Queensland Government introduced the "13% Gas Scheme" in 2005, which was intended to create additional commercial incentives for gas exploration and production by mandating that a specified percentage of electricity generation be fuelled by gas. The Scheme operates by requiring Queensland electricity retailers to surrender a certain number of Gas Energy Certificates ("GECs"), with one GEC representing 1 MWh of electricity sourced from a Queensland gas-fired generator. As retailers are penalised if they don't surrender the required number of GECs, GECs have a value. Owners of gas-fired power stations receive this value, which then flows through to gas producers in the form of additional demand for gas supplies.

While it is difficult to draw a direct causal link, the implementation of the Gas Energy Scheme coincided with a significant increase in natural gas production in Queensland, and appears to have driven significant investment in coal seam methane exploration and development as shown in Exhibit 27 below.

Exhibit 27: Annual Production of Coal Seam Gas in Queensland
P J per Annum



Source Queensland Department of Mines and Energy

While Morgan Stanley is not suggesting NSW should implement a similar scheme, this example is included to illustrate the positive effect a market price signal can have on the availability and supply of gas. Similar commercial incentives are created by the NSW Government's Greenhouse Gas Abatement Scheme (which creates additional revenue for developers of gas-fired power stations, due to their lower greenhouse intensity), and would also be created by a more fundamental shift in gas demand that flows through to a higher wholesale gas price.

4.4 Access to Fuel and Other Inputs (cont'd)

4.4.5 Timely Development of New Gas Transmission Infrastructure

Given that NSW is geographically remote from existing gas sources, development of significant gas-fired generation within NSW is likely to rely on additional gas transmission infrastructure linking NSW with gas sources. This issue is further considered in Wood Mackenzie's report to the Owen Inquiry.

From a commercial perspective, the market will invest (and has invested) in additional gas transmission infrastructure when there is sufficient NSW-based demand to justify the required capital expenditure. Given the "lumpiness" of transmission infrastructure development, the commercial case for gas transmission infrastructure development often relies on a pipeline developer aggregating and contracting with multiple sources of demand to form a "critical mass" of demand to support the infrastructure investment.

In recent times, the NEM has witnessed electricity generators and retailers developing consortia to underwrite new gas transmission development. For example the South East Australia ("SEA") Gas Pipeline, which delivers gas from the Bass Strait to South Australia, was underwritten by Origin Energy, International Power and TRUenergy. These parties all had gas-fired generation and/or gas retail demand in South Australia, and saw an opportunity to aggregate that demand to increase the volume and diversity of gas supplies to the South Australian market.

More recently, AGL has announced a long-term capacity contract with Epic Energy to develop the "QSN" link, which will facilitate the transport of Queensland-sourced gas into NSW, via the Moomba gas hub. This project illustrates one of the benefits of vertical integration in the energy supply chain, as it allows AGL to deliver gas sourced under long-term contracts in Queensland, to its retail market and generation assets in southern states.

Notwithstanding that there are clear commercial drivers for energy players to underwrite new gas transmission infrastructure, continued investment in gas transmission infrastructure is likely to require the following:

- An acceptable level of regulatory risk exposure for the developers of new gas pipelines. We note that COAG and the MCE have focused on gas transmission regulation in recent years, and the AEMC and AER continue to progress reforms in this area
- Timely and efficient progression of land access and development approval for new gas pipelines. Given a new pipeline can be hundreds of kilometres in length, and traverse a large number of landholdings (both state and private), a higher degree of government facilitation of these issues may be required than for other infrastructure which impacts only a specific site

4.4.6 Availability of Gas from Producers and Wholesalers

We note that, unlike the wholesale electricity market which has transparent and publicly available price data, there is more limited price discoverability in the wholesale gas market. Most gas supply contracts are struck on a bilateral basis, with the agreed prices generally not publicly available. Accordingly, it may be more difficult for a party without an existing presence in the wholesale gas market to obtain transparent information about wholesale gas prices and make investment decisions on new power development.

4.4 Access to Fuel and Other Inputs (cont'd)

Greater price transparency is likely to have a positive impact on incentives for gas exploration and production, by providing prospective gas and power investors with better information on market-wide gas supply and demand, on which to base their investment decisions.

An effective wholesale gas market also depends on a sufficient level of competition between upstream gas producers to ensure that power station developers have a choice in who they source their fuel from. Upstream competition can reduce the price risk for a power station developer, improving the investment case for a new power station. Investment in additional gas transmission infrastructure can enhance the degree of competition, by making it physically possible for a given site to be supplied from a larger number of gas-fields, lending to "basin on basin" competition.

While Morgan Stanley expresses no view on the current level of upstream gas market competition, it is clear that developers of gas-fired power stations are reliant upon upstream gas competition to deliver gas at an economic price, and to encourage commercial development of new gas reserves. We would expect that, as gas supply and demand grows, and additional gas transmission infrastructure is developed, the Eastern Australian gas market should mature opening up greater market liquidity and price transparency.

4.4.7 Dynamics of Fuel and Carbon Pricing

While power station developers would prefer to have lower, rather than higher, fuel costs, their approach to managing fuel price risk is more governed by the "spread" between their input costs (i.e., fuel) and their output costs (i.e., wholesale electricity), than by the absolute level of fuel costs. The risk to a power station owner of market-wide fuel price increases is therefore mitigated if the wholesale electricity price reflects movement in fuel prices.

Inappropriate price regulation can significantly increase the fuel price risk that a power station developer is exposed to e.g. by not allowing market-wide shifts in fuel prices to flow through to wholesale and retail electricity prices.

While fuel price risk can be managed at the individual project level by entering into long-term fuel supply contracts, at the market level fuel price movements ultimately need to be reflected in electricity prices, or investors are unlikely to continue to risk capital on power station development.

Fuel price risk can also be minimised if there is effective fuel-on-fuel competition. As noted earlier, effective competition in upstream gas production can reduce the fuel price risk faced by a power station developer. However, effective competition between different fuel types can also minimise fuel price risk.

For example, the ability for power to be generated from coal can provide an external "check" on the level of wholesale gas prices, as if wholesale gas prices rise too high, production and investment will be switched from gas to coal. Eastern Australia currently benefits from gas prices that are low on a global scale. The substantial endowment of coal on the eastern seaboard, and the ability of electricity and gas to be substitutes in many applications, appears to have placed downward pressure on domestic gas prices in the past.

For example, the scenarios below in Table 19 and 20 show the sensitivity of the long-run marginal costs of electricity production to fuel prices and carbon prices.

4.4 Access to Fuel and Other Inputs (cont'd)

Table 19: Scenario 1: Gas Price = $3.50/GJ

	Coal	Gas
Fuel Price ($/GJ)	1.20	3.50
Thermal Efficiency (%)	40	50
Electricity Production (MWh/GJ)	0.1111	0.1389
Fuel Price ($/MWh)	10.80	25.20
Carbon Price ($/t CO_2)	20.00	20.00
Carbon Intensity (t CO_2/MWh)	0.85	0.40
Carbon Price ($/MWh)	17.00	8.00
Total Price: Fuel + Carbon ($/MWh)	27.80	33.20
Plus Other Operating Costs ($/MWh)	2.00	1.00
Total SRMC	29.80	34.20
Plus Capital Costs ($/MWh)	20.00	12.00
Total LRMC ($/MWh)	49.80	46.20

Table 20: Scenario 2: Gas Price = $4.50/GJ

	Coal	Gas
Fuel Price ($/GJ)	1.20	4.50
Thermal Efficiency (%)	40	50
Electricity Production (MWh/GJ)	0.1111	0.1389
Fuel Price ($/MWh)	10.80	32.40
Carbon Price ($/t CO_2)	20.00	20.00
Carbon Intensity (t CO_2/MWh)	0.85	0.40
Carbon Price ($/MWh)	17.00	8.00
Total Price: Fuel + Carbon ($/MWh)	27.80	40.40
Plus Other Operating Costs ($/MWh)	2.00	1.00
Total SRMC	29.80	41.40
Plus Capital Costs ($/MWh)	20.00	12.00
Total LRMC ($/MWh)	49.80	53.40

Source Morgan Stanley analysis

In Scenario 1, gas is priced at $3.50/GJ and coal at $1.20/GJ. Based on the above assumptions about capital and operating costs, and thermal efficiencies (which are purely illustrative only), gas-fired generation has a lower long-run marginal cost than coal at a $20/tonne carbon price.

In Scenario 2, all other assumptions are held constant, except for the cost of gas which is increased to $4.50/GJ. By varying this assumption, the gas-fired power station investment now has a higher long-run marginal cost than coal.

In the above scenarios, gas producers may find it difficult to sell their gas at the $4.50 price, as at that price a coal-fired power station will have a lower LRMC and may therefore be developed in preference to a gas-fired power station. In the absence of a coal option, gas producers would be free to sell their gas at higher prices.

In Scenarios 3 and 4 in Table 21 and 22 below, the carbon price is increased to $30 per tonne.

4.4 Access to Fuel and Other Inputs (cont'd)

Table 21: Scenario 3: Gas Price = $3.50/GJ, $30/Tonne Carbon Tax

	Coal	Gas
Fuel Price ($/GJ)	1.20	3.50
Thermal Efficiency (%)	40	50
Electricity Production (MWh/GJ)	0.1111	0.1389
Fuel Price ($/MWh)	10.80	25.20
Carbon Price ($/t CO_2)	30.00	30.00
Carbon Intensity (t CO_2/MWh)	0.85	0.40
Carbon Price ($/MWh)	25.50	12.00
Total Price: Fuel + Carbon ($/MWh)	36.30	37.20
Plus Other Operating Costs ($/MWh)	2.00	1.00
Total SRMC	38.30	38.20
Plus Capital Costs ($/MWh)	20.00	12.00
Total LRMC ($/MWh)	58.30	50.20

Table 22: Scenario 4: Gas Price = $4.50/GJ, $30/Tonne Carbon Tax

	Coal	Gas
Fuel Price ($/GJ)	1.20	4.50
Thermal Efficiency (%)	40	50
Electricity Production (MWh/GJ)	0.1111	0.1389
Fuel Price ($/MWh)	10.80	32.40
Carbon Price ($/t CO_2)	30.00	30.00
Carbon Intensity (t CO_2/MWh)	0.85	0.40
Carbon Price ($/MWh)	25.50	12.00
Total Price: Fuel + Carbon ($/MWh)	36.30	44.40
Plus Other Operating Costs ($/MWh)	2.00	1.00
Total SRMC	38.30	45.40
Plus Capital Costs ($/MWh)	20.00	12.00
Total LRMC ($/MWh)	58.30	57.40

Source Morgan Stanley analysis

Under the higher carbon price scenario, gas maintains the lowest LRMC at both the $3.50 and $4.50 price. Consequently, gas producers are likely to be able to sell their gas at higher prices under a higher carbon price scenario.

It is important to note that the above examples are illustrative only, however, they are intended to demonstrate:

- The way in which fuel-on-fuel competition in power generation can keep fuel prices in check, which can help in reducing fuel price risk for power station investors
- The sensitivity of fuel price outcomes to carbon prices
- Electricity prices will reflect the arbitrage between fuel and carbon prices

Governments should therefore consider the implications for fuel price competition of any decisions to restrict technologies and fuel types (e.g. by preventing the development of new coal-fired power stations). A better approach towards managing the carbon implications of power generation would be to rely on carbon pricing mechanisms, which would then allow fuels to compete on the basis of carbon-adjusted prices, preserving fuel-on-fuel price competition, reducing risk for power station developers and maximising supply security via fuel diversity.

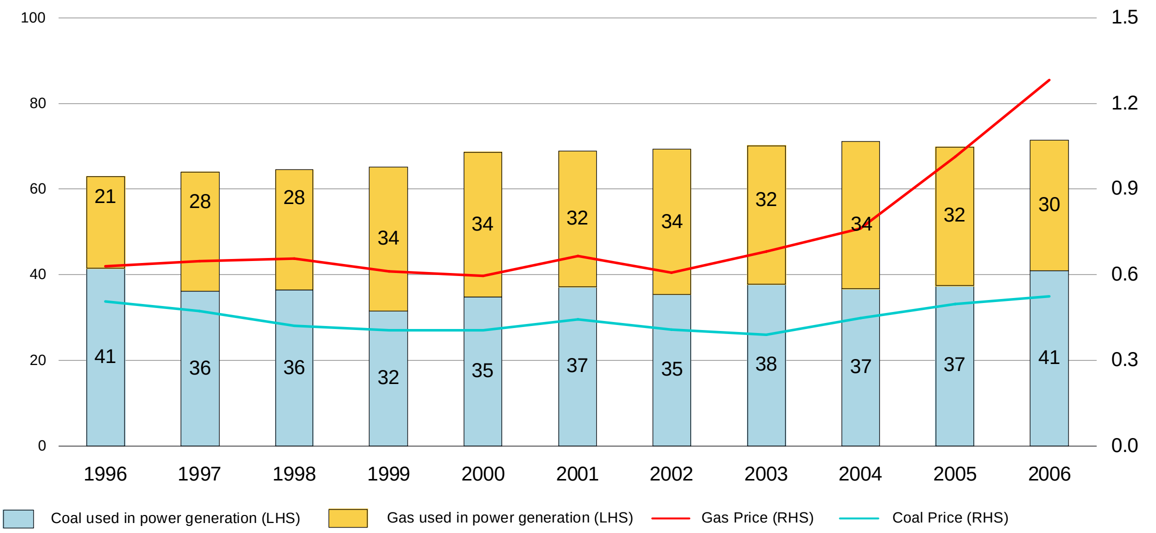
The effect of fuel-on-fuel competition in an electricity market can be observed in the U.K., which generates electricity from a range of fuel sources, including coal, gas and nuclear. The production from each fuel source tends to vary with fuel prices, reflecting the dynamic of fuel switching.

Exhibit 28 below shows the proportion of total fuel used in electricity production accounted for by gas and coal, from 1998 to 1996. Over this period, gas accounted for a growing proportion of electricity production, growing from 21% in 1998 to a high of 34% in 2004. Since 2004, however, the price of gas in the U.K. has increased sharply, and electricity generation has tended to switch from gas to coal. From 2004 to 2006, gas's share declined by 4%, while coal grew by the same amount. This switch is likely to have been greater, had it not been for the EU's emissions trading scheme which offsets some of the relative price increase for gas.

4.4 Access to Fuel and Other Inputs (cont'd)

Exhibit 28: Fuel Prices vs. Fuel Usage

% of Total Fuel Used [1] **Pence per kWh**



Source U.K. Department of Trade and Industry

Notes

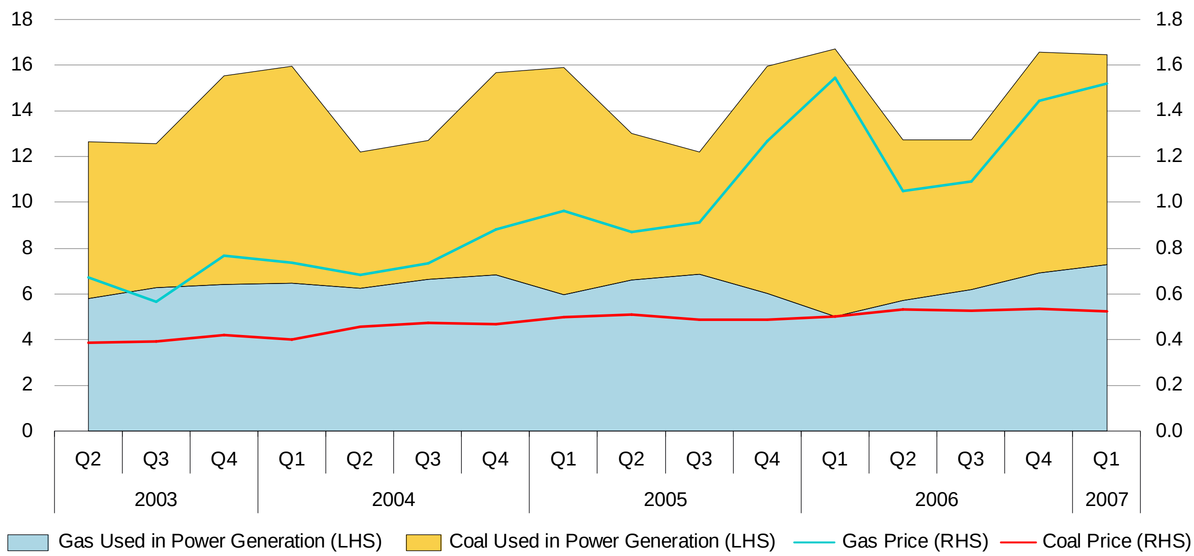
1. Balance of power generation from nuclear, oil and renewables

Seasonal impacts on fuel switching can also be observed in Exhibit 29. The price of gas in the U.K. tends to increase over winter (4Q and 1Q) due to demand for gas for space heating. During the winter months additional electricity production tends to come from coal as it becomes relatively cheaper than gas (even after carbon prices are taken into account). Coal production then drops during the warmer months, when gas prices moderate and demand for electricity falls.

4.4 Access to Fuel and Other Inputs (cont'd)

Exhibit 29: Seasonal Switching of Fuel Sources

Million Tonnes of Oil Equivalent **Pence per kWh**



Source U.K. Department of Trade and Industry

4.4.8 Procurement of Plant

Entering into firm contracts for plant procurement and construction contracts is a fundamental part of new power generation development, and has been raised as an issue in new power development by a number of parties in informal discussions.

A detailed analysis of these issues is not required for our scope of work, and the prevailing procurement and construction conditions apply equally to the private and public sector. However the following issues are worth noting:

- The production of power generation equipment is not such that there can ever be assumed that there is a large stock of "off the shelf" suitable equipment to be purchased—the reverse is far more likely to be true, and 'queues' to purchase suitable equipment from manufacturers have at times being long in recent years
- The construction cost environment varies over time, but current experience is that construction costs appear to be inflating rapidly driven by (i) the global commodities boom and (ii) significant ongoing infrastructure spend in Australia. Given the higher up-front construction costs for coal fired plant, this significantly impacts on the economics for coal
- Uncertainty breeds delay, and where project development approvals run beyond expected timeframes for entering into contracts for procurement and construction, difficulties can be experienced. A proponent may be unable to hold their spot in the order queue for plant and/or be unable to commit to a construction contract, and be faced with a situation where their ability to source plant and labour at a certain cost becomes problematic. Being unable to go to financial close on a new development due to unresolved development approvals may mean procurement and construction contracts being renegotiated or lost altogether.

4.5 Site Access and Planning Approvals

Key Findings

We have little doubt that efficient development approval processes are critical to speedy and economic development of new investment in power generation in NSW. It should be self-evident that developers will not be able to respond in a timely manner to demand if development approvals are not similarly responsive.

Overseas experience with this issue has highlighted difficulties. In particular, we have noted that development difficulties were seen to contribute to the California crisis in 2001, and were addressed by way of a radically streamlined development process after the crisis period.

There is general consensus that:

- Processes in NSW have been improved under the Part 3A process
- But that there remains room for further improvement. There has been feedback that development approvals in NSW remain slower, more costly and less certain than other states

We note that gas-fired plant may attract fewer development approval issues than coal fired plant, and this reduced development risk and quicker timeframe from commitment to operation may be a significant factor in developer favouring gas developments, all other factors being equal. Yet NSW has a significant endowment of coal and imports most of its gas supply. In maximising the economic potential of the State’s assets and local employment opportunities, the NSW Government should be striving as far as is possible to place coal on an equal footing with gas from a development risk perspective.

Project developments can only proceed as quickly as the slowest link in the chain, whether that is the power station itself, new fuel or new transmission. Government needs to do what it can to expedite development process across all the vital links in the chain.

The evidence from the Reliability Panel (refer Section 3) is that new power is being delivered in line with reliability standards, but with something of a narrow margin for error in some states, and so long/unexpected delays in development could compromise reliability. This applies equally regardless of whether the developer is privately or publicly owned

4.5.1 Introduction

Investors need access to a permitted site in a timely manner in order to respond to market developments and install new capacity when signalled by the market.

In any growing economy, processes that support timely development of power generation sites (and ancillary infrastructure) are obviously important for reasons including the following.

- To provide timely response to market needs
- To provide developers with optionality to meet changing conditions and provide arbitrage between different technology and fuel choices. Many developers will pursue more than one development opportunity at any one time to avoid having all their “eggs in one basket”
- To provide commercial tension for the power generation proponent in securing competitively priced supplies, by way of being able to compete different providers at one site (e.g. providers of gas supply

4.5 Site Access and Planning Approvals (cont'd)

and gas infrastructure) against alternate sites and suppliers. Ultimately in a competitive market the benefits of this commercial tension are passed on to consumers

- To mitigate overall development risk, given that other necessary steps in the development chain (equipment procurement, construction) have their own complexities and realisation timeframes
- Because sponsors of competing projects may expect another project to be going ahead, and may not be able to 'catch up' to meet demand if the leading project is unexpectedly delayed
- To mitigate the risk that demand growth might grow more quickly than expected, and threaten reliability
- To allow for efficient growth on existing power sites
- To provide for certainty and efficiency in replacement of plant known to be retiring at a future point in time
- To meet environmental objectives

TRUenergy, which is currently building the Tallawarra CCGT station in NSW, provided the following comment in Box 15 on its rationale to proceed with the development. While a number of factors were at play, the site was one of four key reasons cited by TRUenergy.

Box 15: TRUenergy Rationale for Tallawarra Investment

Key factors underpinning our decision to invest in Tallawarra included:

- Attractive Site—with good access to gas and electricity transmission, water and other important resources, the Tallawarra site was one of the most competitive in the NEM
- Strategic entry to NSW market—TRUenergy is keen to further expand into the NSW energy market. This project provided a good beachhead for that longer-term strategy
- GGAS scheme extension—extending the GGAS scheme to 2020 provided an important additional revenue stream for the project
- Government policy direction—government policy directions and announcements over time led us to have confidence that in the longer-term the broader NSW energy sector policy environment would become more favourable for private investment

While these reasons were sufficient to underpin an initial entry, policy changes will be required before we can significantly expand our exposure to the NSW generation market. In particular access to a large mass market retail customer base will be required to allow us to commit to a major baseload investment

Source TRUenergy public submission to the Owen Inquiry

Relevant precedent experience from the Californian market highlighting the potential threat to reliability from cumbersome development approval processes is summarised in Box 16 below.

The difficulties experienced in California in 2001 were contributed to by multiple factors acting over a single timeframe. One factor that has been commonly identified as contributing to the crisis was a cumbersome and slow authorisation process for new generation plant.

4.5 Site Access and Planning Approvals (cont'd)

Box 16: Lessons from Other Markets: Cumbersome Development Approval Processes—California

The California Energy Commission has broad authority to decide whether the construction of a power plant is in California's best interest, regardless of local-government or public opposition…

...The Energy Commission delivers siting and construction permits for thermal power plants of 50 MW or larger. Plants smaller than 50 MW are licensed by city and council agencies. The siting process varies according to the type of project proposed. For large and complex projects, developers must complete a 12-month Notice of Intention (NOI) process and apply for certification. The applicant has to propose at least three alternative sites. Such procedure is very demanding and time consuming, and it may deter applicants. The last NOI was filled in 1989 and withdraw in 1991. Previous to 1989, the last NOI dated from 1984.

All projects considered by the commission in recent years have been exempted from the NOI process. Applicants have to submit an application for certification. The Commission then has 12 months to make a decision. This period provides time for reviews and notifications to other agencies, if relevant, such as local air and water boards, the California Air Resources Board, the US Fish and Wildlife Service and the Federal Environmental Protection Agency. Concerns have been raised about the Commission's ability to process applications in a timely manner. They have spiked up recently because of California's energy crisis. Although the entire review process is supposed to be completed in 12-months, the process has, in fact, averaged 17 months. This tardiness was due, in part, to external factors such as incomplete applications, delay by other federal, state, and local agencies and, in a few cases, public protests.

The energy crisis that began in the summer of 2000 and continued into 2001 forced a streamlining of procedures for siting review of new generation facilities. The Energy Commission expedited siting processes with the aim of providing new power capacity rapidly. Applications to build new power plants increased significantly. Between July 2000 and June 2001, nearly as many applications were submitted as in the three and a half years since deregulation was approved (18 applications against 19 in the previous period). The commission developed a six-month certification process for thermal plants that are seen as having no adverse environmental impact. A four-month process was established for the expedited approval of simple-cycle facilities. A 21-day process now allows for the expedited approval of plants that will produce extra electricity to cover peak demand. The siting process for peaking plants has been widely used. Thirteen projects were approved by the Energy Commission by August 2001 — 11 of them peaker plants — with a total generating capacity of 9,024 MW. They were scheduled to go on-line between July 2001 and January 2004.

Source © OECD/IEA, 2002, Security of Supply in Electricity Markets. Evidence and Policy Issues

4.5.2 Development Approval Processes in New South Wales

In August 2005, the Government's 'Major Project' legislation came in to force to provide a single integrated environmental planning and approval process for major infrastructure and development in New South Wales. These reforms were implemented through Part 3A of the Environmental Planning and Assessment Act 1979, and replace assessment processes formerly applying to State significant development and major Government infrastructure projects. Part 3A maintains the environmental assessment and public involvement previously required, while simplifying earlier assessment processes. The Minister for Planning is the approval authority for all Major Projects under Part 3A.

Part 3A provides that a development may be declared to be a Major Project through a State Environmental Planning Policy, or through a project-specific Order made by the Minister for Planning. It is virtually certain that any new base-load power station in NSW would constitute a Major Project, and would be assessed and determined by the Minister for Planning under Part 3A.

4.5.3 Part 3A Process

The Part 3A process generally includes:

3) An inquiry and application phase, during which the Department of Planning and other relevant public authorities are briefed on the project and identify key environmental assessment requirements

4) An Environmental Assessment preparation and review phase, during which the proponent prepares an Environmental Assessment to address key environmental assessment requirements, and the

4.5 Site Access and Planning Approvals (cont'd)

Environmental Assessment is reviewed by the Department of Planning and other relevant public authorities to ensure adequacy

5) A public exhibition and submission, during which interested parties are invited to consider the Environmental Assessment and to make a submission on the project

6) A submissions response phase, during which the proponent is required to respond to issues raised in submissions through a Submissions Report or Preferred Project Report

7) A final assessment phase, during which the Department of Planning finalises its assessment of the project and makes a recommendation to the Minister for Planning, who determines the application

The basic Part 3A process is illustrated below in Exhibit 30.

Exhibit 30: Basic Part 3A Process

Initial Inquiry and Confirmation of Part 3A Process

↓

Part 3A Application and Preliminary Assessment
Preliminary identification of key assessment issues prepared by the Proponent

↓

Director-General's Requirements for Environmental
Assessment prepared by Department of Planning in consultation with relevant public authorities maximum 28 days

↓

Preparation of Environmental Assessment
Prepared by Proponent to address Director-General's requirements

↓

Review of Environmental Assessment Adequacy
Undertaken by Department of Planning in consultation with relevant public authorities maximum 21 days

↓

Public exhibition of Environmental Assessment
Minimum 30 days, but may be extended for complex projects or projects subject to a high level of public interest

↓

Preparation of Submissions Report/Preferred Project Report
Prepared by Proponent in response to issues raised in submissions (Submissions Report) and may include amendments to the project (Preferred Project Report)

↓

Director-General's Report and Conditions of Approval
Prepared by Department of Planning
Proponent and relevant public authorities consulted on recommended conditions of approval

↓

Minister for Planning considers and Determines Application

Source Department of Planning

4.5 Site Access and Planning Approvals (cont'd)

Any proposal to establish a new base-load power station in New South Wales will require an environmental impact assessment. Site and fuel issues will drive environmental issues of any development.

Key impacts associated with a base-load power station are likely to include:

- Air quality impacts, with air emissions likely to be the most significant issue in new power development
- Noise and vibration impacts
- Ecological impacts
- Cultural heritage
- Water supply, water quality and hydrological impacts
- Ancillary infrastructure impacts
- Visual implications

4.5.5 Impacts on New Power Projects in NSW

Various parties provided oral submissions to Treasury and Morgan Stanley on their experiences with development approval processes in NSW. In general these were compared unfavourably with other states in terms of cost, time and certainty. We note in this regard that the parties most likely to make strong comment on development approval matters were those who had had difficult experiences, and other parties did not indicate particular difficulties, but this does not fully explain the differences in performance between the different States.

Fewer comments were provided in written submissions. We noted the comments from the written submissions in Box 17 below from ERM, a developer of the Uranquinty power station in Southern NSW.

Box 17: ERM Comments on Development Approvals in NSW

ERM's efforts since 2002 to get substantial gas-fired generation off the ground are detailed in the attached response to the Energy Directions Green Paper (Attachment 2). These efforts have resulted in the commitment and commencement of construction of the 600 MW Uranquinty (Wagga Wagga) gas-fired power station in February 2007, for commercial load from December 2008.

However, it is evident from Figure 2 of that submission that the delayed development of Wagga, which is directly attributable to the difficulties in gaining planning approval, has resulted in NSW generation reserves falling below internationally accepted levels and the State therefore being critically exposed to higher than forecast peak demands and/or generation outages.

While NSW planning approval processes for major projects have been significantly revised and integrated since ERM initiated the Wagga project (primarily as a reaction to the protracted and confused Wagga process), the process remains a significant component of the lead time from planning to commissioning a gas-fired plant, and a source of considerable uncertainty.

ERM accepts that community consultation is an important element of the planning approval process, and has always undertaken such consultation extensively and in good faith. As a proponent of gas-fired generation, in most respects this consultation has involved addressing the legacy of coal-fired generation and public perceptions of smoke-billowing stacks and significant levels of air pollutants.

More problematic is that the application process is to some extent an exercise in second-guessing all possible concerns, at the expense of considerable time and resources, and still being subject to wide-ranging ministerial and delegate discretion. Almost all gas-fired developments now use best available technology with low NOx emissions in power stations with relatively low visual impact, the characteristics of which should by now be well known to environmental regulators.

Source Extract from ERM submission to the Owen Inquiry, June 2007

4.5 Site Access and Planning Approvals (cont'd)

ESAA also provided comment on development approval processes, as noted below in Box 18.

Box 18: ESAA Comments on Development Approval Processes

ESAA notes also that the NSW government can aid the delivery of timely new generation capacity by ensuring transparent, timely and efficient planning assessment approval processes. Planning and permitting processes are a very significant additional time and resource impost on major new facility developments, often entailing more than 2 years of effort. Ensuring that these processes are efficient and avoid vexatious and irrelevant interventions is important to minimise the costs and total project times of multimillion dollar investments.

Source Submission by ESAA to the Owen Inquiry, July 2007

The IEA has noted that development approval processes and associated risks differ between technologies, and as such may become a differentiator even where costs of two competing technologies may be equivalent, as set out below in Box 19. The implication being that there may be a tendency to select gas-fired technologies as these are simpler, easier and less risky from a development approval process. This is a particular issue in NSW, given that the state has significant supplies of coal, and is currently an importer of most of its gas from interstate. Should NSW wish to maximise the value of its coal resources for in-state power development, it should be seeking to streamline development approval processes as much as possible so that coal competes more evenly with gas from the perspective of development time and risk. How evenly coal and gas are treated under a future emissions regime should ideally be a function of a nationally applicable emission regime, and should not complicate approvals at the project level. A case by case approach to emissions would not appear conductive to streamlined development approval processes, nor particularly effective as a policy tool.

Box 19: Lessons from Other Markets: Development Approvals and Technology Choices in International Markets

The risks associated with gaining approval to construct a new power plant differ by technology. The risk is lower and the time span for the approval process is usually shortest for gas-fired power plants and small power plants such as fuel cells and photovoltaics. Although this risk already existed in regulated markets, the ability to pass through the approval costs to consumers is no longer automatic.

The important point for power generation is that the nature of the risks (the "risk profile") is different for different types of generation technology and fuels (refer table below). Thus, even when levelised costs are equivalent and technologies are commercially proven, different risk profiles of different technologies can influence the choice of power generation mix, the range of technologies offered, and the strategies for their development and operation.

Gas-fired technologies have characteristics that should be favourable under these conditions. The relatively low capital cost, short lead time, standardised design and, for some technologies, flexibility in operation provide significant advantages to investors. On the other hand, natural gas price uncertainty remains a large risk to the investor. Nuclear power plants, by contrast, have a relatively low proportion of fuel and operating costs but high capital cost. Furthermore, economies of scale have tended to favour very large plants (1,000 MW and above) resulting in a relatively large capital commitment to a single construction project and hence associated investment risk. Newer designs are more flexible with regard to operations. The potential economic advantages of building smaller, more modular nuclear plants are also being explored by some nuclear power plant designers.

Coal power projects have also tended to become more capital-intensive to take advantage of economies of scale, to meet tighter environmental standards more economically, and to improve fuel efficiency. As with nuclear plants, lead and construction times for coal-fired power plants can be long.

4.5 Site Access and Planning Approvals (cont'd)

Box 19: **Lessons from Other Markets: Development Approvals and Technology Choices in International Markets**

Qualitative Comparison of Generating Technology by Risk Characteristics [(1)]

Technology	Unit Size	Lead Time	Capital Cost/kW	Operating Cost	Fuel Cost	Co2 Emissions	Regulatory Risk
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very Large	Long	High	Medium	Low	Nil	High
Hydro	Very Large	Long	Very High	Very Low	Nil	Nil	High
Wind	Small	Short	High	Very Low	Nil	Nil	Medium
Recip. Engine	Small	Very Short	Low	Low	High	Medium	Medium
Fuel Cells	Small	Very Short	Very High	Medium	High	Medium	Low
Photovoltaics	Very Small	Very Short	Very High	Very Low	Nil	Nil	Low
CCGT	Medium	Short	Low	Low	High	Medium	Low

Source © OECD/IEA, 2003, Power Generation Investment in Electricity Markets

Notes
1. CO2 emissions refer to emissions during combustion/reformation only

4.5.6 Other Factors Affecting New Power Development Projects

Clearly the power station itself is only part of the overall development process. Depending on the project and other circumstances, to bring a power project to fruition may require

- Augmentation of electricity transmission infrastructure
- For coal-fired projects, development of rail infrastructure and/or new or existing coal mines
- For gas-fired projects, development of new gas pipeline infrastructure and potentially new or incremental gas production

All of these components of an overall power development face their own development process issues, which may include the involvement of different government and regulatory bodies.

In terms of coal supplies, the case of the Anvill Hill development near Muswellbrook is well known. Without wishing to enter into any debate about the merits of the development, the development was approved by the Minister for Planning in June 2007. The project had commenced community consultation in early 2005 preparatory to lodging the development approval, and its application to be considered as a Part 3A project occurred in early 2006, around 18 months before the conditional approval was received. The point being that for coal projects that fuel power stations, power station investors will not be able to go to financial close until they have sufficient certainty that the coal mine will also be approved. Approval processes that span 2 or more years for new coal supplies from the time of inception will simply add to the cost and uncertainties associated with development of coal fired power.

Likewise, planning processes for electricity and gas transmission and other ancillary infrastructure can equally slow overall development timeframes.

In terms of issues associated with the long-term nature of planning for electricity transmission, we refer to the extract of the Transgrid submission set out in Box 20 below.

4.5 Site Access and Planning Approvals (cont'd)

Box 20: Extract of Transgrid Submission on Development Processes

Since transmission services are a natural monopoly, transmission investment is regulated and must be undertaken in response to a formal and publicly conducted process to ensure all developments are economically efficient (the "Regulatory Test" process under the National Electricity Rules).

The Regulatory Test process involves the evaluation of all reasonable and feasible development options to ensure that the most economically efficient option to satisfy a given need is selected.

In addition to the Regulatory Test process extensive environmental approvals may be required under NSW legislation, particularly where the network development involves the construction of new high voltage transmission lines.

In combination, these approval processes typically result in long lead times for the construction of new transmission lines. These lead times can be as long as 6–7 years. The need for transmission network augmentation and the lead times for such works need to be considered in the delivery times for new baseload generation servicing NSW.

Source TransGrid submission to the Owen Inquiry, June 2007

In terms of issues associated with the planning for gas transmission developments, we refer to the extract of the APIA submission set out in Box 21 below.

Box 21: Extract of APIA Submission on Development Processes for Gas Transmission

The negative impact of regulation occurs at a number of levels and affects pipeline development. These negative impacts range from difficulties in gaining planning approvals (and unnecessary complexity when dealing with multiple jurisdictions) through to the impact of heavy-handed economic regulation of pipeline revenue. These regulatory impacts have the potential to cause both a delay to, and reduction in, the levels of investment in energy infrastructure (including electricity generation and pipeline infrastructure). However, if there is sensible coordination of planning approval requirements and appropriate responsiveness from economic regulatory bodies lead times for pipeline projects can match those of generation plant.

Source APIA submission to the Owen Inquiry, July 2007

4.6 Access to Capital

Key Findings

Access to capital to fund new developments is a necessary precondition for development of new power stations.

We believe that the state of capital markets and the availability and pricing of capital will move through cycles typical of financial markets. Cyclical behaviour in capital markets has been visible over the last few years. In the event capital markets are in a negative cycle at times of new investment, this is not likely to be a barrier to investment, but may increase cost of funding and hence required returns. This simply reflects the fact that 'new entrant pricing' levels will be higher at times when capital is expensive, and lower at times when it is cheap.

Capital will be attracted, and made available most cheaply, to the most robust and sustainable business models. As highlighted in Section 4.3 and discussed also below, we believe there is evidence to support the contention that capital will be made available most cheaply to firms that are vertically integrated, are portfolio generators, or that have significant long-term off-take contracts. In contrast the pure merchant power plant operating independently in a pool market is likely to have higher revenue volatility and higher costs of funding.

In none of our meetings with the private sector and in no submissions was access to capital cited as a problem or barrier to new investment. On the contrary, potential developers see capital markets as being in a supportive phase. We believe listed and unlisted Australian equity is available to invest in new commercially viable power developments, and investment trends in recent years are for Australian equity to replace former foreign equity ownership that originally entered the market via privatisation.

In discussions a number of parties advanced the view that the business case for baseload plant was simpler than peaking plant, given that economically viable baseload plant is likely to dispatch a high proportion of its capacity on a relatively continuous basis, in contrast to peaking plant and to a lesser extent intermediate plant. Large greenfield baseload plant are capital intensive, generally will have low SRMC and be highly cash generative. Such assets may be built by existing listed energy companies, but also may be included in infrastructure fund—like vehicles which trade on cashflows and cash yields.

Emissions uncertainty has the potential to be a barrier to new capital formation, but sponsors indicated that the bank market was not currently raising emissions uncertainty as an issue. This is not as surprising as it may seem at face value, since even with adverse carbon outcomes, financiers to reasonably leveraged projects are still likely to be paid out at 100c in the dollar—it will be equity investors that lose out. Unsurprisingly, it is those same equity investors who are reluctant to invest in coal fired plant in the existing emissions environment, as noted elsewhere in this report.

4.6.1 Introduction

Investors need access to capital in order to efficiently fund new power developments. While capital can come in many and varied forms and descriptions, it essentially comprises either debt or equity capital.

Capital for power projects can (and does) come from both Australian and overseas sources. Australia has open financial markets and minimal barriers to movement of capital. Foreign investment in

4.6 Access to Capital (cont'd)

Australia is generally encouraged and most foreign investment applications are approved—in 2006 the Foreign Investment Review Board ("FIRB") did not decline a single related non-property acquisition, and we are not aware of any foreign investments in the power sector being rejected by FIRB [1]. Foreign investment in the Australian power sector is substantial and is compared with Australian equity ownership in Table 23 below.

Table 23: Australian and Foreign Investment in the Australian Power Sector

Private Sector Investment in Australian Power Generation: Existing and Committed

Participant	Asset	Fuel	Ownership %	MW [1]	Participant	Country	Asset	Fuel	Ownership %	MW [1]
Australian Investment					Foreign Investment					
AGL Energy	Loy Yang A	Coal	32.5	690	Alcoa	US	Anglesea	Coal	100.0	160
	Pinjarra 1 & 2 [2]	Cogen	33.3	93	Contact Energy	NZ	Oakey	Gas	25.0	72
	Somerton	Gas	100.0	150	Infratil Energy	NZ	Angaston	Oil	100.0	40
	Southern Hydro	Water	100.0	650	InterGen Australia	US/China	Callide C	Coal	50.0	460
	Torrens Island	Gas	100.0	1,280			Millmerran	Coal	100.0	850
Alinta [3]	Bairnsdale	Gas	100.0	94	International Power	U.K.	Dry Creek	Gas	100.0	156
	Bell Bay	Gas	100.0	240			Hazelwood	Coal	91.8	1,469
	Glenbrook	Cogen	100.0	112			Kwinana	Gas	49.0	58
	Newman	Gas	100.0	105			Loy Yang B	Coal	70.0	700
	Pinjarra 1 & 2 [2]	Cogen	66.7	187			Mintaro	Gas	100.0	90
	Port Headland	Gas	100.0	175			Pelican Point	Gas	100.0	485
Babcock & Brown	Neerabup [2]	Gas	70.0	231			Port Lincoln	Gas	100.0	50
Babcock & Brown Power	Braemar	Gas	85.0	387			Snuggery	Gas	100.0	63
	Ecogen	Gas	73.0	700			Canunda	Wind	100.0	46
	Flinders	Coal	100.0	770	Marubeni	Japan	Smithfield	Gas	100.0	160
	Newgen Kwinana	Gas	70.0	224	Mitsubishi	Japan	Gladstone	Coal	7.1	120
	Oakey	Gas	50.0	143	Mitsui	Japan	Kwinana	Gas	21.0	25
	Redbank	Coal	100.0	150			Loy Yang B	Coal	30.0	300
	Uranquinty [2]	Gas	70.0	448			Loy Yang A	Coal	5.5	117
Energy Brix	Morwell	Coal	100.0	300			Tarong North	Coal	15.0	66
ERM Power	Braemar	Gas	15.0	68	NRG Energy	US	Gladstone	Coal	37.5	630
	Neerabup [2]	Gas	30.0	99	Rio Tinto	U.K.	Gladstone	Coal	42.1	708
	Newgen Kwinana	Gas	30.0	96	Sumitomo Light Metal	Japan	Gladstone	Coal	8.5	143
	Oakey	Gas	25.0		TEPCO	Japan	Loy Yang A	Coal	32.5	690
	Uranquinty [2]	Gas	30.0				Tarong North	Coal	35.0	155
Origin Energy	Bulwer Island	Cogen	100.0	32	TRUEnergy (CLP)	Hong Kong	Hallett	Gas	100.0	180
	Darling Downs [2]	Gas	100.0	630			Tallawarra	Gas	100.0	400
	Ladbroke Grove	Gas	100.0	80			Yallourn		100.0	1,480
	Mt Stuart	Gas	100.0	288	YKK	Japan	Gladstone	Coal	4.8	80
	Osborne	Cogen	100.0	180						
	Quarantine	Gas	100.0	96						
	Roma	Gas	100.0	74						
	Worsley	Cogen	100.0	120						

Notes

1. Source: FIRB Annual Report 2005–2006

4.6 Access to Capital (cont'd)

Table 23: Australian and Foreign Investment in the Australian Power Sector

Private Sector Investment in Australian Power Generation: Existing and Committed

Participant	Asset	Fuel	Ownership %	MW (1)	Participant	Country	Asset	Fuel	Ownership %	MW (1)
Transfield	Yabulu	Gas	100.0	220						
Transfield Infrastructure	Collinsville	Coal	100.0	180						
	Loy Yang A	Coal	14.0	297						
	Townsville	Gas	100.0	220						
	Kemerton	Gas	100.0	260						
	Kwinana	Gas	30.0	35						
Other Financial Institutions	Loy Yang A	Coal	15.4	326						
	Hazelwood	Coal	8.2	131						
	Ecogen	Gas	27.0	259						
Total Australian Investment				**11,085**	**Total Foreign Investment**					**9,951**

Notes
1. Share of total
2. Under construction
3. May be acquired by Babcock & Brown Power

Foreign investment in the NEM is substantial as shown above and is broadly equivalent to Australian ownership on a net equity MW basis. The recent asset swap between AGL and TRUenergy of the Hallett and Torrens Island Stations took Australian equity MW ownership past the level of foreign ownership for the first time. Australian net equity MW ownership has grown through development of new power stations by Australian investors and also by acquisitions from selldowns from departing foreign investors in recent years. This recycling of capital from foreign to Australian investors in recent years reflects the nature of the Victorian and South Australian privatisations which were trade sale processes where vertical integration and cross-ownership between generation and downstream entities (such as retailers) were discouraged, and where no generation businesses were listed on the ASX. This is unlike the U.K. liberalisation process, where large generation businesses were floated on the London Exchange so establishing large focused privately-owned generation businesses from commencement of liberalised markets.

The largest Australian investor in power assets in Australia is of course government. According to the Productivity Commission, government investment in electricity assets (power generation, distribution, transmission) dominates the private sector and is [1]

- The largest single investment class by government, exceeding water assets and other assets such as rail, forestry etc.
- Valued at over $60Bn in 2006
- Easily exceeds 20,000 MW in the NEM

Due to the limited privatisation of these government-owned electricity assets across Australia, and the simultaneous consolidation activity over the last few years, Australian ownership of privatised

Notes
1. Productivity Commission, Performance of Government Trading Enterprises 2004/2005 to 2005/2006, 2007

4.6 Access to Capital (cont'd)

electricity assets in general, including power generation, has consolidated into a small number of firms which have progressively increased in scale. These businesses compete with government-owned business and foreign owned businesses. The major Australian-owned businesses which control power stations in the NEM include AGL, Origin Energy, and Babcock & Brown Power ("BBP"), all of which are ASX listed, BBP most recently. Smaller Australian generation players include Transfield Services Infrastructure Fund which is now listed, the privately-owned ERM Power, and the energy business of Wesfarmers.

The Australian experience of government-dominated ownership of power generation is somewhat similar to New Zealand, where Contact Energy and TrustPower are listed on the NZ exchange, but the other major participants remain government-owned. Similarly most Canadian generation remains government-owned.

This contrasts with U.K. and US markets. In the U.K., virtually all assets are privately-owned and have been since the early 1990's. The U.K. Government's quasi-ownership of a proportion of the cashflows of the nuclear-powered British Energy, which arose from assistance provided to the company, is the notable exception. In US markets the vast majority of generation capacity and customers reside with private investor owned utilities, some utilities are owned by local government or cooperatives in remote regions.

4.6.2 Access to Capital Provided By Government

The Government position on new capital for investment for the SOCs has in the past been a stated preference for private sector funding of new power generation in NSW. Regardless of commercial merit, the Government decision to fund Delta's Colongra OCGT has been seen by the private sector to have moved away from this principal.

We understand there are no preset guidelines for the SOCs on what new projects may or may not be approved, each business case will stand or fall on its own merits. Notwithstanding this general approach it seems clear that the retail SOCs in particular have either not had vertical integration opportunities (like power stations) yet approved, or have not pursued such projects in the likelihood that they would not be approved. We note that ETEF historically has provided a large default hedge, but this device is being progressively removed in the future.

In terms of existing policy settings, Government has a series of linked policies which are publicly available on the NSW Treasury website, and which include:

- The Government Guarantee Fee Policy for Government Businesses, which essentially exposes Government-owned businesses to the risk-related cost of debt they would have faced if they were required to borrow funds based on their stand-alone credit rating
- The Financial Distribution Policy, which required a dividend target to be negotiated annually between Government as shareholder and board/management of the relevant SOC, taking into accounted expected post-tax profits, cash flow, working capital and investment needs
- The Capital Structure Policy for Government Businesses aims to ensure that Government businesses are financed by an appropriate mix of debt and equity. Formal reviews are event driven—less formal but regular reviews occur annually

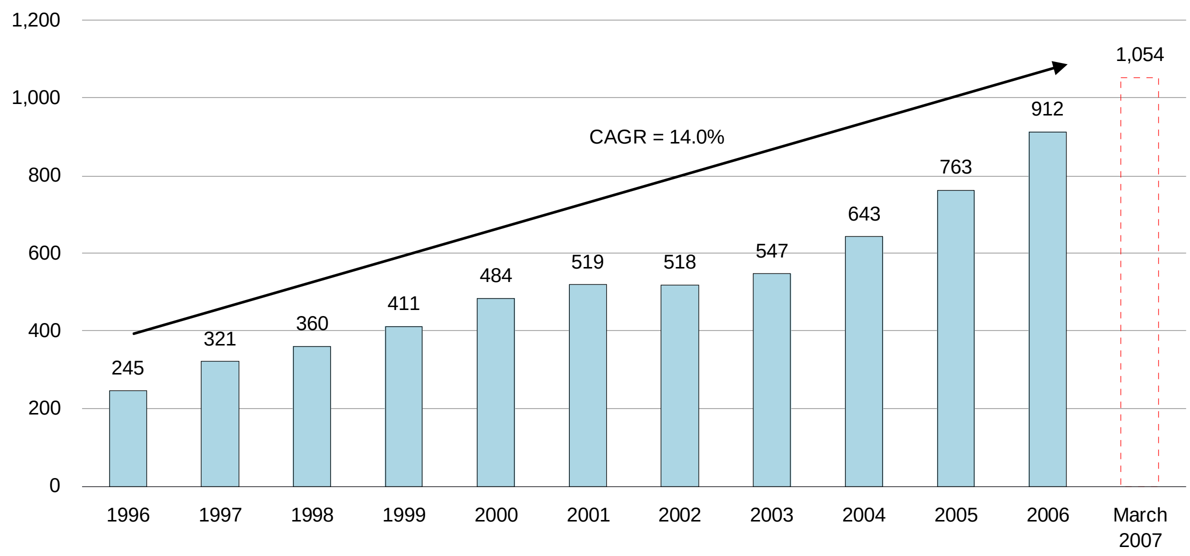
4.6 Access to Capital (cont'd)

We note that Government has a stated preference for stable returns over riskier enterprises which may lead to capital growth. This differentiates Government equity ownership from that of the private sector, where growth is rewarded.

4.6.3 Access to Equity Markets for New Investment

Equity markets in Australia are strong and have gone from strength to strength over the past decade significantly influenced by the compulsory superannuation regime that is now in place. Superannuation growth over the last decade is evidenced in Exhibit 31 below.

Exhibit 31: Superannuation Fund Growth—As at 30 June A$Bn
Total Superannuation Assets in Australia



Source Australian Prudential Regulation Authority

Notwithstanding strength of Australian equity markets and superannuation inflows, opportunities to invest in electricity assets has been limited until recent years, and then mainly in regulated assets classes and not power generation. In our view this reflects two factors which are supply-side driven

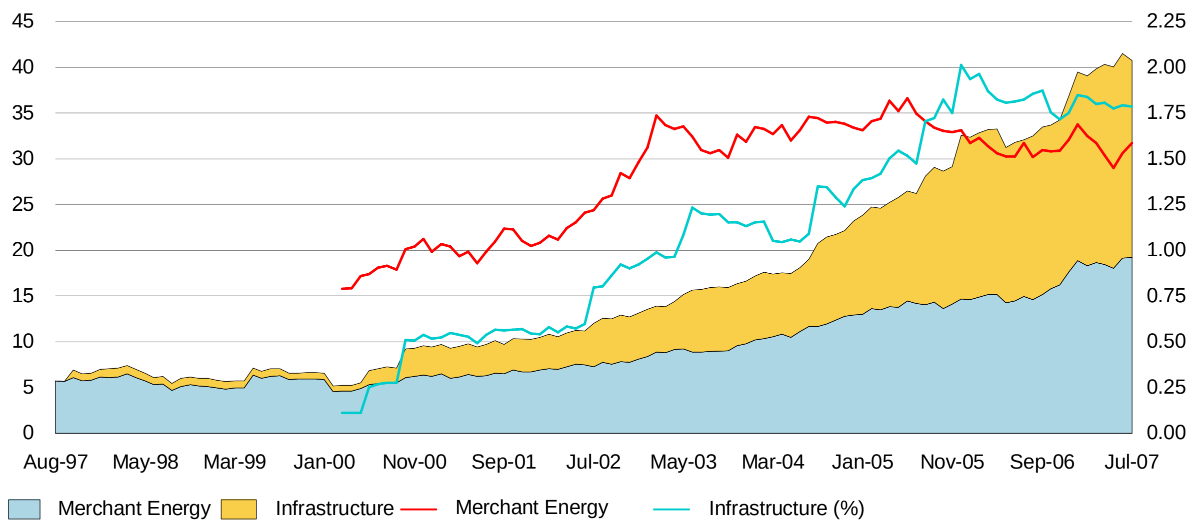
- Only a small fraction of government-owned electricity assets have been privatised. As such, while on the one hand there is a government-enacted compulsory superannuation regime which forces investment by working Australians, there are at the same time large pools of assets locked up on government balance sheets and have simply not been made available for investment at this time
- When assets were privatised in the 1990's and 2000, a number of these assets were purchased by foreign investors via trade sales and were not available to Australian equity. When these foreign investors departed in the early 2000s, these assets became available and a large number of them are now listed on the ASX through a number a vehicles

4.6 Access to Capital (cont'd)

Exhibit 32 below highlights growth in the Utilities and Infrastructure Index over the last ten years and the growth of the ASX over the same period. It highlights the growth in importance of lower-risk infrastructure-like assets in recent years, from close to a zero base prior to 2000. It also highlights that the merchant energy sector, which includes a large part of the power generation assets and the retail businesses, has grown in absolute terms but as a percentage of the overall assets listed on the exchange, has essentially been static for the last four years. This reflects the point above, that supply of assets to the market has been limited, and a large amount of assets remain in government ownership.

Exhibit 32: Combined Market Capitalisation of ASX-Listed Utilities Companies [1]

Last 10 Years, A$Bn (000s) **ASX 200 Market Capitalisation (%)**



Source Morgan Stanley Analysis

Notes

1. Merchant Energy sector includes AGL Energy, Contact Energy and Original Energy. Infrastructure sector includes Alinta, APA Group, Babcock & Brown Infrastructure, Babcock & Brown Wind, Challenger Infrastructure, DUET, Envestra, Hastra DUF, SP AusNet, Spark Infrastructure, Transfield Infrastructure and Viridis

The IPO of both BBP and Transfield Services Infrastructure Fund is significant in the context of future new power development in NSW. These businesses, which have both been listed in the last 12 months, reflect the first offerings of businesses that are focused to a large extent on power ownership in the NEM, both contracted and merchant. The fact of these businesses being listed can only help educate investors, the financial media and research analysts alike on power investment as a (relatively) new asset class for investment.

If governments increase the supply of generation assets to the Australian investment market, there is no reason to believe that efficiently priced capital would not be made available to support it. We have seen no evidence to suggest that investment in being limited by a tight pool of equity capital in Australia—given large and sustained superannuation inflows the reverse appears to be true—the problem is that there are insufficient assets in which to invest, as most power assets remained owned by government.

4.6 Access to Capital (cont'd)

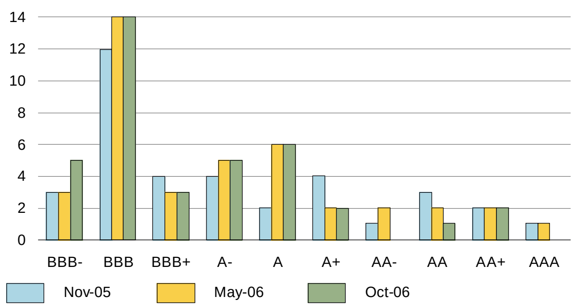
We note in this regard that in a recent PWC Survey, in response to the question of what should be done to increase investment in energy infrastructure in Australia, the number one response was *"privatisation of government-owned assets."* (1)

4.6.4 Access to Debt Markets for New Investment

Debt market access for power and utility companies is not solely reliant on credit ratings, but credit ratings do play an important role in the sector overall. Recent reporting on distribution of credit ratings by Standard and Poors for utilities in Australia and the US is highlighted below in Exhibit 33. It can be clearly seen that in both markets there tends to be a clustering around the BBB level while strong ratings (A and above) are typically influenced by sovereign ownership, and do not reflect the true underlying credit risk of the business if it were stand-alone from its government equity owner. Per the discussion in Section 4.3, business models that incorporate vertical integration or portfolio generation diversity are likely to attract better credit ratings than stand-alone merchant generation.

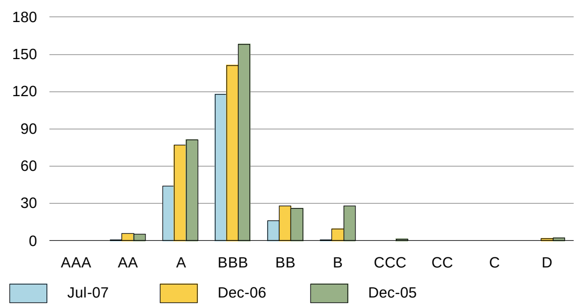
Exhibit 33: Ratings Distributions for Australian and US Utilities

Australian Utilities Long-Term Ratings Distribution
No. of Issuers



Source Standard & Poor's 2006

US Utilities Long-Term Ratings Distribution (1)
No. of Issuers



Source Standard & Poor's 2007

Notes
1. Dates represent current and previously published report card data. Previous report cards included gas, merchant power, water, pipeline and midstream energy companies

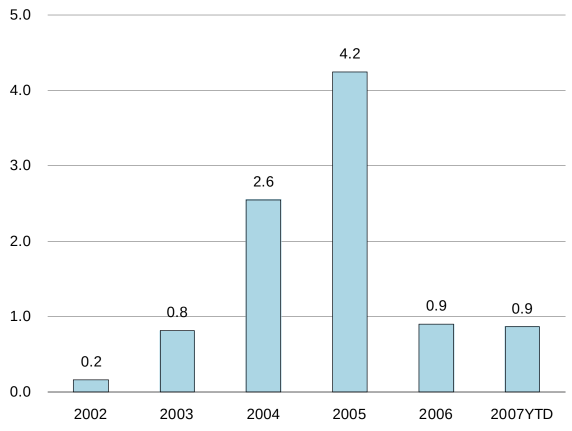
Debt market availability suffered earlier this decade in the wake of the collapse of Enron and a general decliner in confident in power markets. This has reversed in recent years with stability and confidence returning to the sector. Exhibits 34, 35, 36 and 37 below charts debt raising for power generation development across major markets and shows growing levels of support across most markets over the last five years. While capital markets will cycle through different phases, there is no reason to believe debt capital will be denied to commercially viable power projects. Note that these charts include loans for acquisitions, new projects and capital expenditure. They exclude loans raised for refinancing and general corporate and working capital purposes.

Notes
1. PWC, Energy and Efficiency, Utilities Global Survey 2007

4.6 Access to Capital (cont'd)

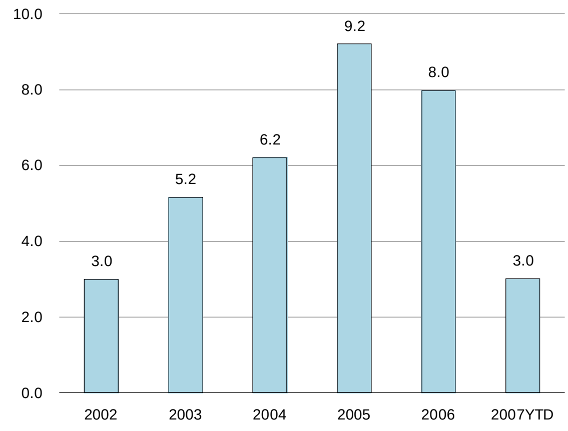
Debt Raising in International Markets

Exhibit 34: Debt Raised for Power Generation Development: Australia/New Zealand
US$Bn



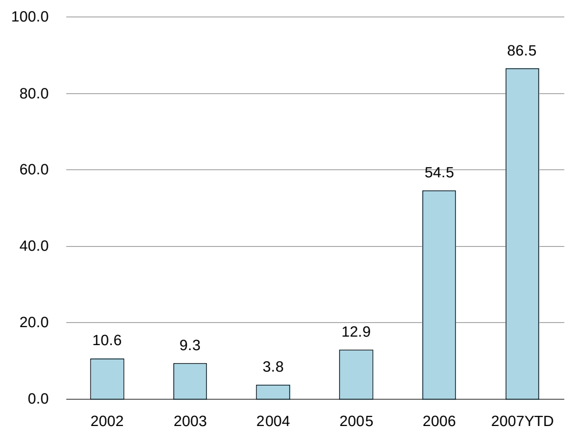
Source Morgan Stanley Analysis

Exhibit 35: Debt Raised for Power Generation Development: Asia Pacific
US$Bn



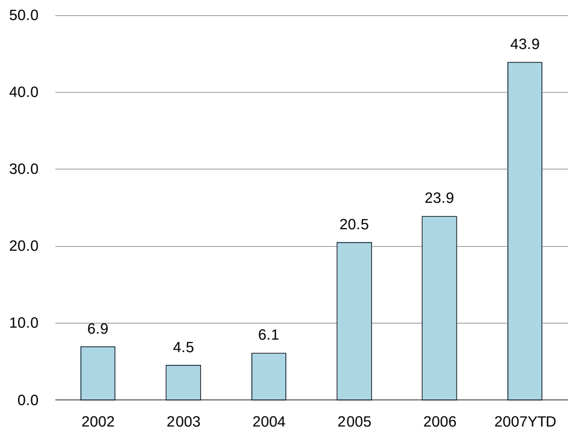
Source Morgan Stanley Analysis

Exhibit 36: Debt Raised for Power Generation Development: Western Europe
US$Bn



Source Morgan Stanley Analysis

Exhibit 37: Debt Raised for Power Generation Development: North America
US$Bn



Source Morgan Stanley Analysis

4.6.5 Other Evidence

We note in Box 22 below a comment from the KPMG report on capital markets that accompanied the ERIG report. Informal conversations with private investors by Morgan Stanley has elicited some similar comments.

4.6 Access to Capital (cont'd)

Box 22: Other References to Investor Views on Availability of Capital

"Notwithstanding these developments investors are of the view that, in principle at least, there is no shortage of capital that might be prepared to take energy market risk (e.g. one investor suggested for example that they had "several billion" potentially to invest in baseload, merchant generation)".

Source KPMG survey for ERIG, Impediments to investment in Australia's energy market, the views of investors. KPMG November 2006

4.6.6 Impacts on New Power Projects in New South Wales

We close this section by noting that capital markets do indeed move in cycles and the post-Enron period was a difficult time in both US and U.K. markets in particular, but this also had flow on impacts around the world, including in Australia, where a number of offshore investors (particularly North American) withdrew in 2002–2003. Box 23 highlights some of the evidence from that period. The events of this period were unprecedented, but capital markets have recovered and as shown above and elsewhere in this report, private sector investment has rebounded and is in continuing in those markets that were damaged in the 2001–2003 period. Most recently, during what has been an aggressive capital cycle (and in a complete turnaround from 2002) have been two very large private equity purchases of US utilities; Kinder Morgan in 2006 for US$22Bn and TXU (pending) for US$37Bn.

However foreign investor interest in the Australian market appears to have been one of the more permanent casualties of the 2002–2003 period, with relatively few investors outside Asia looking to enter Australia. This highlights that stable, transparent and predictable market structures are likely to breed confidence and investor (debt and equity) willingness to participate.

4.6 Access to Capital (cont'd)

Box 23: A Bankers Perspective of 2002

What Actually Happened

- Power prices collapsed in the US and U.K.
- Major industry players that invested heavily in merchant power and trading have collapsed or are struggling to survive…
- …Better models need to be developed to attract capital into critical sectors and countries where new projects will be needed

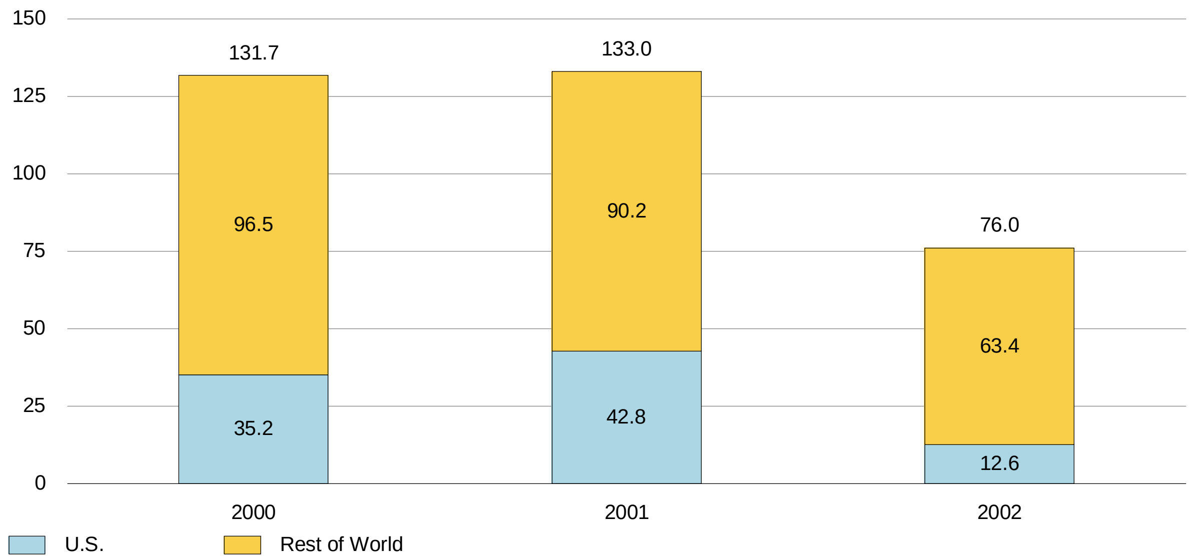
Disengagement of Investors and Lenders

- Lenders and investors thought they understood the rules governing the power system when they invested. The destruction of the clear understandings investors thought they had has caused them to abandon the sector, resulting in a collapse of equity and debt prices
- This disengagement will last until a new understanding of a new reality is gained and confidence is restored that this understanding will not be shattered again…
- …Regulators need to create a climate of stability in which reasonable expectations of investors can be fulfilled
- Debt issuance (bank and fixed income) in 2002 declined 42% to $76 billion… in the US debt issuance (bank and fixed income) declined 70% to 12.6 billion

Debt Issuance Dries up

Global Power Project Finance Market

US$Bn



Source De Luze, Investment in Power Generation: A Banker's Perspective, 2003

4.7 Policy Certainty and Stability

Key Findings

The NEM is subject to ongoing proposals for reforms and reviews, which can create a high level of policy and regulatory risk for power generation investors.

While it is recognised that governments need to continually review energy market policies to ensure that energy markets are meeting desired policy objectives, too much policy uncertainty can be a barrier to efficient generation investment. This is particularly true of power generation investment, which is highly capital-intensive and long-term.

Two particular sources of policy uncertainty have the potential to significantly impact generation investment in NSW, and as a condition to private investment in generation, need to be resolved as a matter of priority:

- The NSW Government’s policy on future publicly-funded investment in power generation
- Key design features of a national emissions trading scheme

4.7.1 Introduction

Investment in power generation infrastructure is a technically complex, commercially risky and capital-intensive exercise. Before a power station is even commissioned, power station developers are required to assess, mitigate and manage a range of risks including:

- The risks associated with locating, acquiring and obtaining development approval for an appropriate site
- Sourcing fuel and negotiating fuel contracts
- Obtaining a sufficient level of debt finance at appropriate interest rates
- Construction costs and timetables

Once a power station is operating, there are ongoing risks of:

- Wholesale electricity prices, which can vary to up to $10,000/MWh in half hour intervals
- Availability and operational efficiency of the plant
- Changes in interest rates, which can impact the cost of servicing debt and the returns to equity investors
- New power stations being built, which may have a lower operating cost than existing power stations, and which can therefore displace existing power stations in the merit order

While the above risks are not trivial, power station developers are able to manage these risks through a variety of mechanisms, including:

- Transferring construction risks onto third parties, via fixed price construction contracts
- Entering into long-term fuel supply contracts
- Entering into hedge contracts or long-term power supply contracts with retailers and other market participants, to reduce their exposure to wholesale electricity price volatility

4.7 Policy Certainty and Stability (cont'd)

- Hedging their interest rate exposure

Markets have developed to handle most of the commercial risks associated with power station development. However, markets have limited capacity to handle policy and regulatory risks, as it is more difficult to assess in advance, model and contractually transfer.

4.7.2 Analysis

The capital-intensive and long-term nature of power generation investment means that investments can be particularly sensitive to major regulatory changes, which tend to be asymmetric in nature (i.e. they can have significant potential downside risk, but limited upside risk).

KPMG, in its November 2006 report to the Energy Reform Implementation Group, referred to a number of examples of policy and regulatory uncertainty that were cited by investors, noted in Box 24 below.

Box 24: Investor Views on Policy and Regulatory Uncertainty

"A policy cycle which outpaces the market cycle (i.e. the market has not yet been through one investment cycle, but that has not stopped various stakeholders and policy makers forming views on its performance);

The lack of an unambiguous, time bound energy policy and a lack of timely implementation of that policy;

Proposals to tinker with market rules, whilst not dealing with key impediments (which might make the former redundant);

The reopening and re-examination of issues (e.g. this [the ERIG] review and the debate about market structure) and the lack of direction to regulators on these matters;

The short-term nature of many market transactions (e.g. contracting in the retail market), which uncertainty exacerbates."

Source KPMG, Impediments to investment in Australia's energy market: The views of investors

In addition to the above issues, Morgan Stanley would also highlight the inter-governmental nature of the NEM, which has policy settings determined by representatives of seven different elected governments (Queensland, New South Wales, Australian Capital Territory, Victoria, Tasmania, South Australia and the Commonwealth). Given the large number of governments involved in NEM-related policy decisions, there is the potential for electricity-related matters to be subject to multiple electoral cycles, limiting the opportunity for reform to be pursued in a consistent and timely manner. The move to more national-based approaches through forums such as the MCE are strongly supported by virtually every participant.

Submissions to the Owen Inquiry tended to reinforce the view that investors require a degree of policy certainty in order to commit the required capital for major generation investment.

For example, Alinta made the following point:

"Investors need clear rules to undertake a long-term commitment such as a baseload power station. Appropriate policies need to be set firmly in advance of a project starting date (given the long lead times involved) and need to remain in place for the long-term to give investors confidence that rules will not be changed arbitrarily"

Regulatory and policy uncertainty has negatively impacted generation investment in other markets, as illustrated by the Spanish example below in Box 25.

4.7 Policy Certainty and Stability (cont'd)

Box 25: **Lessons From Other Markets—Lack of clear and consistent policy and regulatory setting settings—Spain**

Spain is still in a transition phase, going from a completely regulated to a liberalised market. In such an ongoing process of market reform, it is very important to ensure that efficient price signals are given to power generators, energy suppliers and consumers. The process of administratively determining integrated tariffs may undermine the power of price signals in all energy related markets when these prices are set too low to enable competitive markets to emerge.

The Spanish energy regulator, the National Energy Commission (CNE), is well resourced and performs analysis and development which is crucial for the efficiency of the Spanish energy sector. The role of the regulator is, however, only consultative in most of the issues that it provides input for. Final regulation and decisions must be approved by the Ministry of Industry before they can take effect. Therefore, the strength of having an independent party to pass judgment, different from the rule-making and implementing authorities, may be lost. Regulatory independence is an important indicator for investment certainty for new entrants into the energy markets of a country, and it could be argued to be almost a prerequisite for strong competition. The experience of other countries shows that those with strong regulators have benefited more from increased liberalisation, while those with less strong and independent regulators have lagged behind.

Despite the commitment by the Spanish government to further liberalisation of its energy markets, there is a perceived lack of transparency and investment certainty in its energy sector. The government should therefore consider ways to give the CNE powers to perform the actual regulation of these markets, to assure investors and new entrants. To achieve this, it may have to reconsider the procedures for the appointment of board members and executive staff at CNE, by, for example, the creation of an independent committee that has the task of selecting the chairman and board members.…

…Spain has managed to develop well-functioning regulatory and market institutions and thereby possesses the framework for an efficient electricity market. With the many other energy policy challenges that have also been met during the transition, the electricity market has, however, evolved with a continuously high level of regulation and political involvement. This regulation has served a purpose but has also created many distortions in the market. The greatest challenges ahead allowing Spain to reap the full benefits of market liberalisation now appear to be in dealing with these distortions. The Spanish electricity market is now at a stage where the regulation that was meant to ease the transition has become a hindrance for its further development.

Source © OECD/IEA, 2005, Energy Policies of IEA countries, Spain

4.7.3 Key Issues

Two particular sources of policy uncertainty have the greatest potential to impact generation investment in New South Wales, and are worth singling out for further comment:

- Government policy on government funding of future generation investment
- Future carbon pricing policies

4.7.4 Government Policy on Government Funding Of Future Generation Investment

A particular issue of concern to the private sector relates to government policy in relation to new generation investment i.e., whether governments intend to invest in new generation themselves, or are committed to leaving new generation investment to the private sector, dictated by market forces.

The potential impact of government-driven investment on market outcomes is considered in more detail in Section 4.8. However, it is worth noting the specific issue of *uncertainty* in government investment policies.

The New South Wales Government has given mixed signals to the market in this regard. It has indicated on a number of occasions its strong preference for the private sector to invest in new power generation. For example, the Energy Directions Green Paper (December 2004) stated:

"The Government doesn't consider it appropriate to invest further capital in high risk commercial activities like electricity generation, when this capital and risk exposure can be provided by the private sector."

4.7 Policy Certainty and Stability (cont'd)

Notwithstanding the above statement, the Government subsequently approved Delta Electricity developing the Colongra open-cycle gas turbines at Munmorah, on the Central Coast. While Morgan Stanley has no view on the merits of this particular investment, the fact that the Government approved State-funded power generation investment after previously indicating a preference for private sector investment, and in the face of alternative investment by the private sector (e.g. Tallawarra), is sufficient to heighten the policy uncertainty applying to subsequent power generation investment in New South Wales. A number of parties indicated to Morgan Stanley concern and uncertainty over government investment directions following the Colongra decision.

The Colongra decision is almost a microcosm of a number of the major issues canvassed in this report

- From a Government perspective, the decision to go ahead with Colongra is completely consistent with the policy approach enunciated in the 2004 Green Paper. It reflected the fact that peak generation was required, but that the private sector was not committing in time to satisfy Government that reliability would be maintained
- The private sector takes the view that this illustrates that government will always build early, and is evidence of stranding risk

At first glance these views seem completely irreconcilable. But we believe the answer lies in the current industry structure in NSW

- There is simply little commercial incentive for the private sector to invest in NSW at present
- Private retailers do not have businesses of scale that require them to invest in generation
- Private portfolio generators do not own any assets in NSW, with all generation exposed to the NEM lies in the hands of Government

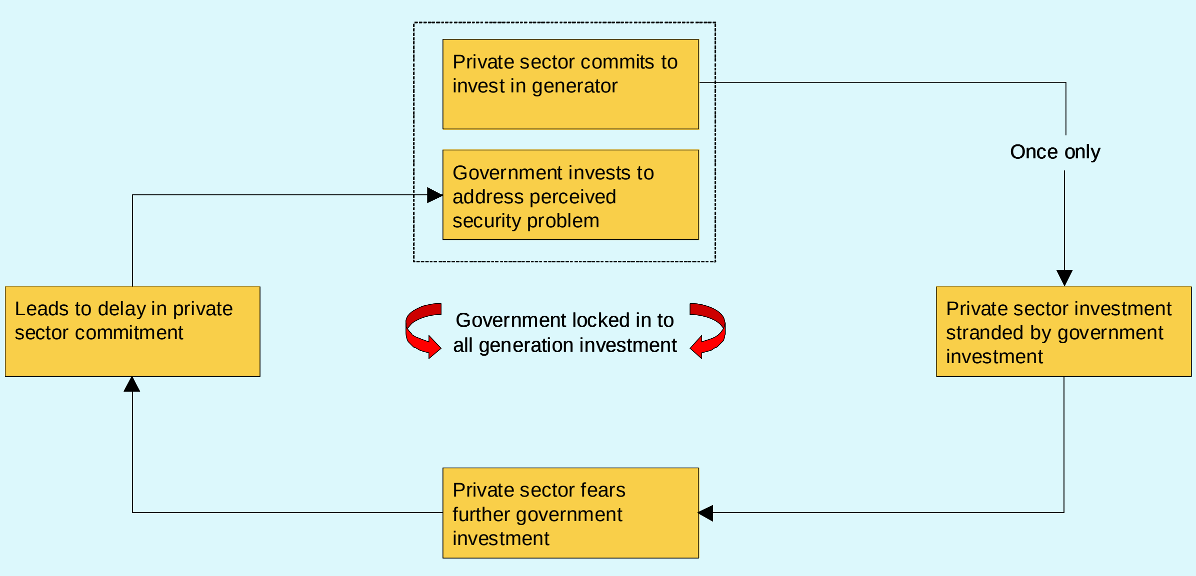
In this context, it is no surprise that the private sector only has very modest investment incentives, perceives barriers to entry in investing in NSW in the current industry structure, and that the burden of funding fell on Government. Without change to the current industry structure, Government should plan to fund all future generation in NSW, and certainly all baseload (the private sector may invest, but the Government could not be confident that it would). In our view only changing the industry structure will deliver the incentives that will bring on private sector investment in a timely manner.

In its submission to the Owen Inquiry, TRUenergy highlighted the impact that uncertainty around government investment intentions can have on private sector investment decisions with the following diagram set out in Exhibit 38 below.

4.7 Policy Certainty and Stability (cont'd)

Exhibit 38: TRUenergy Diagram on Uncertainty in Government Investment Policy

Impact of Uncertainty of Government Investment Policy on Private Sector Investment



Source TRUenergy

TRUenergy's diagram suggests the following chain of impacts resulting from market uncertainty about government investment policies:

- The market is uncertain of the government's investment intentions, particularly where the uncertainty has been exacerbated by prior government investment
- The market is then less confident of making future investment, and may not make timely investment commitments
- The government perceives that private sector investment commitments are not forthcoming, and decides to invest (again) itself in order to secure supply
- The private sector then becomes increasingly nervous about making its own investment in the future, leading to further investment delays, further perceptions of supply security by government, and further government investment

It is through this cycle of uncertainty that the government could find itself locked in to making all future generation investment. To break this cycle, it would be necessary for the government to make a credible and unequivocal commitment not to invest further in generation, in order to give the private sector the necessary confidence to make future investment.

The Energy Retailers Association of Australia also reflected on the impact that market uncertainty around government investment intentions can have on the private sector's confidence to invest:

"… generation investment driven by governments, particularly where it preempts the market, may create "moral hazard" issues. That is, private investors may come to expect the government will always provide a regulatory backstop avoiding the need for private participants themselves to undertake such investment. Indeed, because there will be a strong temptation for the government to

4.7 Policy Certainty and Stability (cont'd)

invest too early (which some have suggested has occurred in Qld for instance) participants will have an expectation that whatever investments they undertake will have a good chance of being stranded."

Key different experiences in two Canadian markets are worth considering. In the Ontario market cited in Section 4.8, government intervention in the wholesale market to cap price at low levels meant government had to subsequently bring on new investment. In the Alberta experience cited below in Box 26, again government intervened but in a pro investment framework, with dramatically different consequences, that can be contrasted to many other examples of price caps set at commercially inappropriate levels

Box 26: Lessons from Other Markets: Nondistortionary Policy Settings—Alberta, Canada

The wholesale market in Alberta opened in 1996, with the retail market opening in 2001. Alberta experienced very high prices on market open, which was unfortunately at essentially the same time as the California energy crisis.

Government moved to cap prices—but rather than capping at an inappropriate level, prices were instead capped at a suitably high level, and provided short-term relief via cash rebates rather than by distorting investment signals by seeking to influence price. The collection of the higher prices by utilities was also somewhat deferred, to smooth the impact on consumers.

The high price cap was well above long run marginal costs, and as such preserved a positive signal for new entrant investment.

Wholesale prices subsequently retreated and new generation occurred. While Government responded to the high prices in such a way to protect consumers, it also did so in a manner that preserved the fundamental workings of the market via price signals, and consequently incentivised new entry.

Source Morgan Stanley research

A good example where government investment has created fears of stranding is the New Zealand market, where the government sought to mitigate drought and risk impacts by commissioning a standing reserve power station, but in a way that created uncertainty as to wholesale market outcomes. This is described in Box 27 below.

Box 27: Lessons from Other Markets: Distortionary Policy Responses and Government Investment Uncertainty—New Zealand

The New Zealand Government implemented a reserve generation scheme to in-principle deal with drought risk. While the mitigation of drought risk appears to be a sensible use of a reserve capacity scheme, the trigger price for the scheme appears relatively low and would cap peak prices that would otherwise be experienced due to nondrought related generation scarcity. No separate scheme was instituted to compensate for the capping of peak spot spices. A new industry regulator has been established with wide discretions and significant ministerial oversight. These active government interventions appear to have made the regulatory environment less certain and delayed investment.

Source PricewaterhouseCoopers, Infrastructure stock take: infrastructure audit, 2004 and Electricity, Investment and security of supply in liberalised electricity systems, Richard Meade, 2005

4.7.5 Carbon Policy Uncertainty

The future treatment of carbon emissions can have the potential to significantly impact the economics of new power stations, particularly more carbon intensive power generation technologies, such as coal.

Australian governments have implemented a range of policy measures aimed at reducing the carbon intensity of power generation. These include:

- Schemes which directly target carbon emissions, such as the NSW Government's Greenhouse Gas Abatement Scheme

4.7 Policy Certainty and Stability (cont'd)

- Schemes that less directly target carbon emissions, but establish incentive frameworks for investment in particularly lower-emission technologies, such as the Commonwealth Mandatory Renewable Energy Target ("MRET") scheme and the Queensland 13% Gas Scheme

Notwithstanding the existence of the above schemes, there is widespread recognition that the most effective method of reducing carbon emissions from the stationary energy sector is a broad-base carbon trading scheme.

Following the recommendations of an Emissions Trading Task Group, the Commonwealth Government has announced its intention to implement a nation-wide emissions trading scheme from 2011–2012. The federal opposition has announced its intention to implement a similar scheme, but to commence in 2010.

While there now appears to be bi-partisan support for carbon trading, leading to a high probability that a carbon trading scheme of some form will be implemented, the market is yet to be advised of the key features of a carbon trading scheme, which will include:

1) The medium-term (e.g. 2020) aggregate emissions target which a carbon trading scheme will seek to achieve, which will be a key determinant of carbon prices
2) The point in time after which generation investment won't be "grandfathered" (ie. won't receive a free carbon permit allocation), which will determine the extent to which individual generation projects will be exposed to carbon price risk
3) The penalty for noncompliance, which will effectively "cap" the price of carbon
4) Which businesses will and will not be included in such a scheme
5) The process for allocation of free permits, and auctioning of other permits
6) The emission reduction activities which will be eligible to generate carbon permits, as offsets to carbon emissions from power generation (this is a particularly important issue for investment currently producing abatement certificates under the NSW Greenhouse Gas Abatement Scheme, as it will determine the likelihood of those activities continuing to generate carbon-related revenues under a national emissions trading scheme)

Consequently, while investors in new power generation infrastructure are now likely to face the impacts of carbon trading from 2010–2011, they do not yet have critical details of how carbon trading will operate in order to assess the impact on specific investment options. This creates a high level of uncertainty for new power generation investment (particularly for more carbon-intensive investment, like coal-fired power stations) which may lead to a "freeze" in investment.

Based on our discussions with a number of industry participants, Morgan Stanley believes it is highly improbable that any party will invest in a new coal-fired power station until key details of the national carbon trading scheme are released, due to the significant carbon risk that such an investment would attract.

While it may be possible for a government to underwrite the risk of new coal-fired investment in the interim (e.g. by entering into a contract with a power station developer under which the government agrees to compensate the developer for any material adverse effect of carbon trading policy on the value of its investment), this would simply transfer the risk from investors to taxpayers, and not remove

4.7 Policy Certainty and Stability (cont'd)

it entirely. The only effective way to resolve the risk is for the key details of the carbon trading scheme to be developed and released to the market.

Of the above outstanding details, we believe that items 1, 2 and 3 are the most critical to be resolved, as they will most directly impact the economics of a new power station.

Policy uncertainty can also impact investment in lower emission gas-fired power stations, as developers will not be certain whether carbon will be priced at a level that will allow a gas-fired power station to be competitive with coal. However, this is of lesser concern to investors due to the existence of the NSW Greenhouse Gas Abatement Scheme, which currently provides additional revenues to developers of gas-fired power stations due to their lower greenhouse intensity. It is also less important for gas-fired stations which may mainly operate at peak-intermediate price periods, as the percentage impact of carbon will be lower. Nonetheless, developers of gas-fired power stations are exposed to the risk of transition between the current NSW scheme and the national emissions trading scheme, which again can only be fully resolved by development and communication of the details of the national emissions trading scheme. At present the private sector appears comfortable investing in gas-fired power. In the absence of clarity on emissions, or a high electricity price with sufficient "headroom" to absorb large forecasting errors of the price of carbon, private investors will only be building gas-fired power in NSW. This will "keep the lights on" but may not be the least cost choice, and in the absence of effective competition from coal, may be higher than it would otherwise be.

4.7.6 Practical Effect of Current Carbon Policy Uncertainty

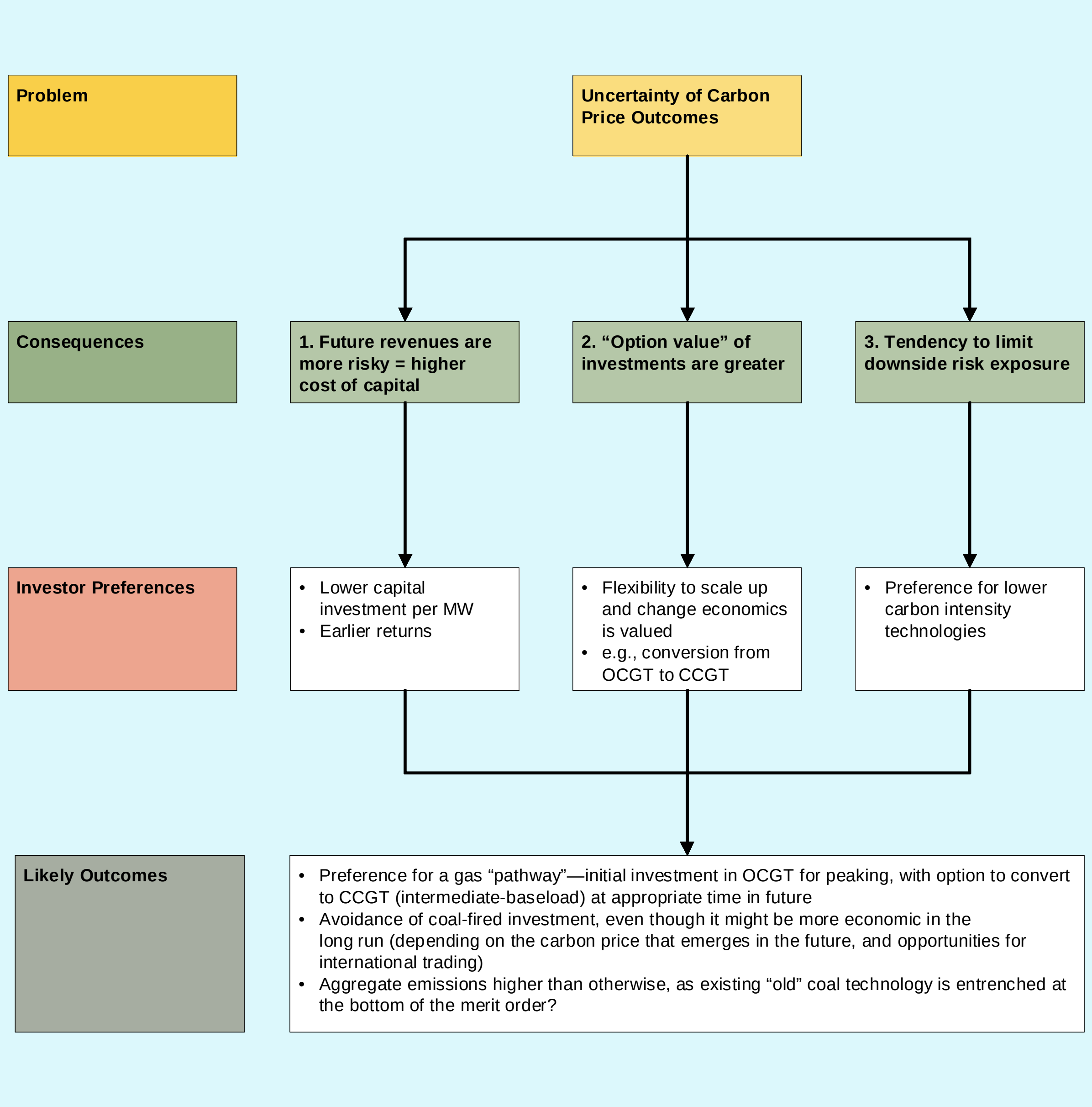
As noted, the current carbon policy uncertainty appears to be impacting most on investor appetite for coal-fired power station development, with the practical effect that any coal-fired investment is highly unlikely to proceed until the policy uncertainty is resolved.

This leads to gas being the default option for power station investment in the interim.

A framework for how investors may make decisions in the face of uncertainty of carbon policy and pricing is illustrated below in Exhibit 39.

4.7 Policy Certainty and Stability (cont'd)

Exhibit 39: Investment Decision-Making Under Carbon Pricing Uncertainty



In the face of uncertainty around future carbon prices, investors will tend to demand a higher return on their investment, they will more highly value "optionality" in their investments, and they will tend to limit downside risk exposure by avoiding investment in higher emissions power generation.

These tendencies result in a natural bias away from coal-fired power stations.

Coal-fired power station investment is more capital intensive on a per MW basis than gas-fired power station investment. This means:

4.7 Policy Certainty and Stability (cont'd)

- The cost of "getting it wrong" is higher, than for a gas-fired power station
- Coal-fired power stations have greater downside risk if carbon prices end up being higher than forecast

In the absence of uncertainty, investors may be more prepared to invest the high level of capital required to develop coal-fired power stations, as they would be able to better understand the likely future economics of coal vs. gas. Due to Australia's relative abundance of black coal, coal-fired power stations *might* prove more economic in the long-run. However, this would depend on future carbon prices and opportunities for international carbon trading, as well as the basic cost differential between coal and gas.

Uncertainty regarding future carbon policies has also impacted investment in other markets, as the examples set out in Boxes 28 and 29 below illustrates.

Box 28: Lessons From Other Markets: Emissions Uncertainty Impacting on New Investment—United Kingdom

Morgan Stanley recently advised the U.K. Government on investor perceptions of the generation investment climate in the U.K. as part of the Government's Energy Review leading up to the issue of the U.K. Government's Energy White Paper: Meeting the Energy Challenge, released in May 2007. To quote from the White Paper on emissions modelling undertaken by the U.K. Government:

"Our modelling indicates that limited visibility of future fossil fuel, carbon and electricity prices, and investor uncertainty over the continued existence and form of the EU ETS post 2012 are key factors affecting new investment decisions. These uncertainties increase investment risk, making it more difficult for companies to assess whether a particular power station investment will be profitable. Investors have highlighted that they are particularly concerned about international carbon frameworks after 2012, given that a post-Kyoto framework has yet to be agreed globally and the Directive underpinning EU ETS is under review, with changes set to take effect from 2012. This is why we attach a great deal of importance to successful negotiation on the strengthening of the EU ETS.

Our modelling also shows that by providing investors with greater certainty about the future carbon policy framework we can expect to see increases in the level of spare capacity and reductions in the volatility of electricity prices, bringing benefits to the wider economy by lowering the risk of electricity supply interruptions and reducing costs to the economy. Greater certainty over expected prices facilitates firms' assessment of the investment risks and returns of possible future projects. Additionally, greater certainty that the costs of carbon will be incorporated into electricity prices improves the economics of low carbon generation."

Source Department of Trade and Industry, Meeting the Energy Challenge, A White Paper or energy, May 2007

Box 29: Lessons from other Markets: Emissions Uncertainty Impacting on New Investment—New Zealand

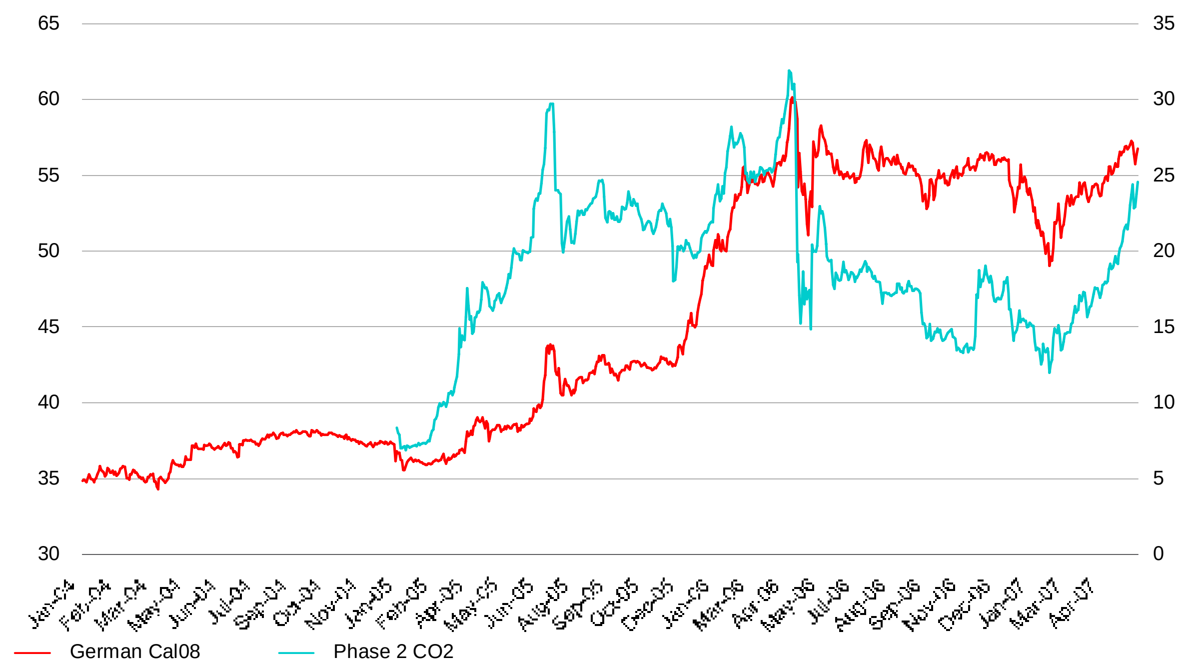
A PricewaterhouseCoopers report in 2004 on the state of infrastructure in New Zealand (a Kyoto Protocol signatory) indicated that emissions uncertainty was a factor in delaying investment decisions, since the level of carbon tax would materially impact on investment economics, and in effect, firms were better off sitting and waiting for clarity before making firm decisions.

Source PriceWaterhouseCoopers, Infrastructure stock take: infrastructure audit, 2004

Other markets have shown a propensity to factor in carbon prices in advance of the implementation of a carbon trading scheme. Exhibit 40 below shows forward prices for delivery of electricity in Germany in 2008, the first year of the Phase 2 of the European Union emissions trading scheme. Forward electricity prices have been correlated to carbon prices from as early as 2005, well in advance of the actual commencement of the Phase 2 trading scheme.

4.7 Policy Certainty and Stability (cont'd)

Exhibit 40: Forward Electricity Prices vs. CO_2 Prices in Germany



Source Morgan Stanley

Morgan Stanley expects that a similar situation will arise in Australia—forward prices for delivery of electricity post-commencement of an emissions trading scheme will reflect the market's expectation of carbon prices well in advance of the actual implementation of the scheme. It is therefore essential that the key parameters of a carbon trading scheme be communicated early, so that the forward market is fully informed and can incorporate the "right" carbon price signal. This will assist investors in building the most economic generation infrastructure for a post-emissions trading market.

Resolution of uncertainty around future carbon policy will allow investors to properly consider, and assess the risks of, all generation technologies. A greater range of generation technologies and potential fuel sources can only enhance security of electricity supply, as well as promoting fuel-on-fuel competition.

4.8 Commercially Determined Prices

Key Findings

As is evident from Section 3, the price in the NEM is:

(i) The single investment signal under the current market design

(ii) A key part of the reliability settings

Accordingly any move to influence price outcomes, no matter how well intentioned, risks compromising new investment and reliability. As such price caps should be avoided where at all possible—consequences in other markets have been disastrous and invariably the government who sets the cap is the one who finds itself stuck with the problem of cleaning up the problem that it created.

The two rationales most often cited for retail price caps are:

(i) Social policy/equity reasons

(ii) To cap the influence of market power

We find that price caps are a particularly blunt and inappropriate instrument to address these problems where a price outcome is the symptom, not the cause of the problem that policy makers are trying to address. Social policy objectives can be dealt with by other means, and market power should be dealt with by merger rules etc. rather than pricing instruments. Price caps may deter new entrants to a market and therefore act as a barrier to entry and concentrate the market power of incumbents, not dilute it.

4.8.1 Introduction

In making an investment in a new power station, investors must take a view on future electricity prices, as these will determine the future revenue stream for the power station.

In a gross pool market structure, like the NEM, future electricity prices are critically important as there are no market-based capacity payments available to power station investors. While the developer of a power station can contract away some or all of its price risk exposure, for example by entering into a long-term contract with a retailer or major electricity user, ultimately someone needs to bear power price risk and therefore needs to form a view on the likely direction of future power prices, in order for investment commitments to be made.

Power prices are fundamentally determined by the interaction of supply and demand. While the unique features of power markets make modelling supply and demand complex, a number of market consultants have developed sophisticated models of the National Electricity Market which can forecast generator bidding and investment behaviour and demand patterns, and use these to forecast future electricity prices. Being models, they are naturally only as good as the assumptions and methodologies they use, and a number of equally valid modelling approaches can produce different price forecasts. However, the fact that future electricity prices *can* be modelled allows generation investors to assess the likely range and probabilities of future price outcomes, and use sensitivity and scenario analysis to test the impact of different price outcomes on the financial returns of their investment.

4.8 Commercially Determined Prices (cont'd)

It is more difficult, however, to model and predict the impact of policies and actions of a non-commercial nature on future power prices. There are a range of actions which have in the past, or may have the future potential to impact on the free functioning of the wholesale electricity market, including:

- Mechanisms which cap electricity prices, either at the wholesale level (such as the Value of Lost Load, or VOLL) or at the retail level (such as retail price regulation)
- Policies which provide technology-specific investment subsidies, such as mandatory renewable energy schemes or gas generation targets
- Non-market based risk management schemes, such as the NSW Electricity Tariff Equalisation Fund
- Electricity trading and bidding behaviour which is motivated by noncommercial factors
- Noncommercial investment in generation capacity e.g. investment directly by government for noncommercial purposes, or investment by government businesses which do not have the same financial disciplines imposed on them as are imposed by private capital markets

It is important to note that some of the above may have legitimate policy objectives, and Morgan Stanley is not suggesting that they should be avoided *per se.* For example, the $10,000 MWh wholesale price cap is an important element of a market where electricity consumers do not have a direct role in setting power prices, and is intended (amongst other things) to act as a proxy for the maximum price that consumers are prepared to pay to avoid supply interruptions. Mandatory renewable energy schemes may have a legitimate role in facilitating the commercialisation of new technologies, which otherwise may not be developed by the market in its current form.

However, notwithstanding the legitimate public policy objectives of such measures, their potential to impact electricity market outcomes (and therefore future investment in power generation) should be considered by governments implementing such measures, and factored into the cost-benefit analysis underlying policy decisions. Any action in the electricity market will have a reaction, and those reactions may not be positive.

This section further considers some of the above measures which have the greatest potential impact on private investment in power generation.

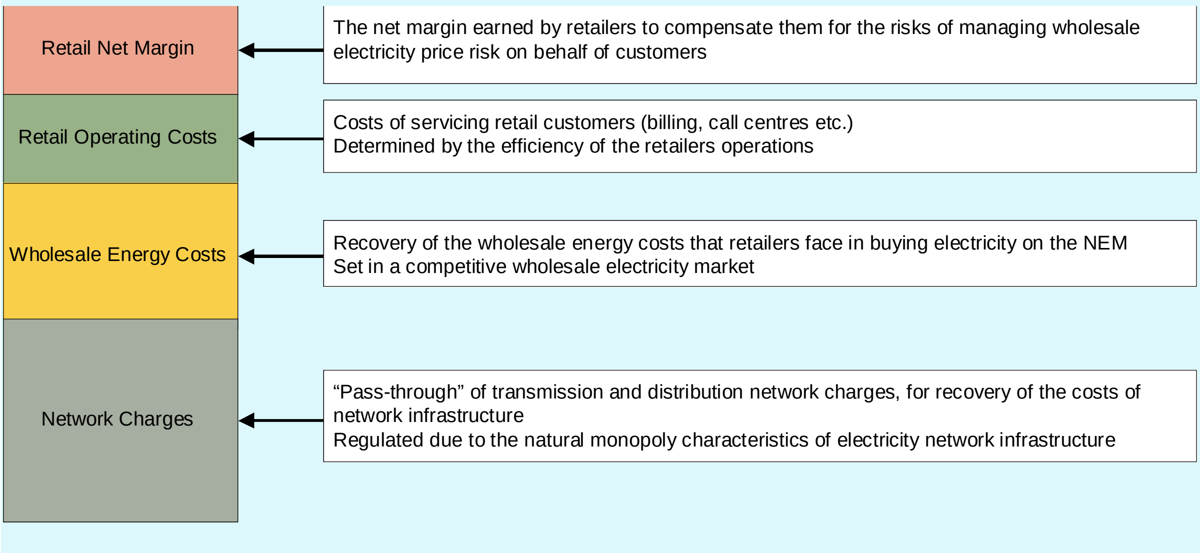
4.8.2 Retail Price Caps

Currently, New South Wales electricity customers consuming <160 MWh per annum are entitled to receive electricity supply from their local electricity retailer at a tariff that is regulated by the Independent Pricing and Regulatory Tribunal. Such customers are also free to obtain electricity supply from an alternative retailer at a nonregulated tariff. However, in practice a customer is unlikely to switch to a nonregulated tariff unless it provides a cheaper price than regulated tariffs. Consequently, the retail tariffs determined by IPART effectively cap the retail price of electricity for all NSW customers consuming <160 MWh per annum.

4.8 Commercially Determined Prices (cont'd)

Retail tariffs comprise four key components, as set out in the following diagram in Exhibit 41.

Exhibit 41: Components of a Retail Tariff



While power stations sell their output directly into the wholesale electricity market, the revenues available to the broader market to recover the costs of power generation ultimately come from retail tariffs. Inappropriate retail tariff regulation, which sets tariffs below the full cost of generating, transmitting and distributing electricity, and providing retail services to customers, can result in insufficient revenue being available market-wide to fund investment in new power stations. Without a clear source of revenue, the market simply will not invest in generation.

An example of policy actions directed at capping prices, which have distorted electricity markets is set out in Box 30 below. This graphically demonstrates that where government seeks to intervene in price signals, it is government (i.e., tax payers) who are likely to face the consequences.

Box 30: Lessons from Other Markets: Distortionary Policy Responses—Ontario, Canada

After a lengthy restructuring process, and the establishment of an independent regulator, the retail electricity market in Ontario was opened on 1 May 2002. All customers, regardless of size, had the right to choose their supplier of electricity. Customers not making this choice formally would be served by default through their local (usually a municipal) distributor who would buy spot electricity on their behalf. Electricity in Ontario is produced mainly from nuclear power (43%), coal and oil (25%), hydro (25%) and natural gas and other (7%). About three quarters of the electricity is generated by provincially-owned Ontario Power Generation. Approximately 1.1 million residential consumers, about one-quarter of the total, had made arrangements for a fixed-price contract by the time the market was a few months old.

While prices during the spring were lower than regulated prices, a combination of an unusually hot summer and delays in bringing nuclear generating capacity back into service led to prices that were much higher than the government had anticipated. Combined with higher consumption, bills to Ontario consumers not covered by a fixed-price contract rose by approximately 30%. Voter dissatisfaction with the government over the market was very high.

As a result, in late 2002, the government passed legislation that froze prices for small consumers and institutional consumers (e.g. hospitals, schools, municipal buildings) at the level it was before the opening of the market (CAD 43/MWh43) until at least May 2006,

4.8 Commercially Determined Prices (cont'd)

Box 30: Lessons from Other Markets: Distortionary Policy Responses—Ontario, Canada

compensated consumers for the additional amounts they had paid up to that point,

froze rates for transmission and distribution of electricity, and empowered itself to change these rates previously determined by the regulator. Despite these changes, the wholesale market was left in place and the government is required to make up any difference between the wholesale cost of electricity and the frozen price.

These steps had a number of important short-term consequences: market prices remained high, and the government was now responsible for subsidising the prices paid for electricity. These subsidies cost CAD 550 million during the first 12 months of the operation of the market.

The government's action has also had an effect on electricity demand. Consumers covered by the price cap have less incentive to conserve electricity. This in turn has raised demand and the market price for electricity. It has also increased costs to the government (who must take the spot price) and to those large consumers that had chosen to remain exposed to spot price. The continuing rise in demand has led the government to contract for an additional 270 MW of peak generating capacity to act as additional operating reserve. The contracts, worth CAD 70 million, are for nine months only.

The high wholesale prices should begin to fall as capacity under construction at the time of the crisis is completed. However, no new projects have been proposed by the private sector since the government announced its shift in policy. The market operator has suggested the market will be short of peak capacity as early as 2005.

The government's temporary intervention to subsidise retail electricity prices has been set at a price far below that of the entry price for new generation (in the range of CAD 55 to 60/MWh). While the wholesale market remains open and able to set prices freely, investors are more reluctant to move into the Ontario market because of the high political

risks. As a consequence, prices in the wholesale market have to move even higher before new investment will occur. This leads to higher government subsidies and to increased risks of power shortages, which in turn leads to direct government intervention to add peaking capacity. Thus, the government finds itself paying for higher prices and for new supply. In October 2003, the new government announced its intention to raise the cap level.

Source © OECD/IEA, 2003, Power Generation Investment in Energy Markets, International Energy Agency 2003

A number of submissions to the Owen Inquiry noted the link between retail prices and revenue for generation investment, and highlighted the risk that inappropriate retail price regulation could stifle necessary investment.

TRUenergy's submission was representative of this view.

The optimum way to set retail prices is for the market to establish the appropriate pricing level. However, prior to competition being established, governments have opted to impose retail price caps.

In situations where price caps are in place, it is essential that they be set at levels that:

- *Allow competition to develop*
- *Are sufficient to fund ongoing industry investment in the industry, and are*
- *Established with the intent of transitioning to contestable markets as early as possible*

– TRUenergy

The ESAA commissioned CRA International to review the costs and benefits of retail price regulation in Australian energy markets. CRA's findings in relation to the policy rationale and effect of retail price regulation are outlined in Box 31.

4.8 Commercially Determined Prices (cont'd)

Box 31: **Extract from CRA International Report for the ESAA, the Effects of Retail Price Regulation in Australian Energy Markets**

"Retail price regulation is a device to control the exercise of market power by one or more firms in a market. It follows that in order for retail price regulation to confer public benefits, firms must possess market power and be able to utilise it to sustain prices in excess of cost to earn supranormal profits. However, in a sufficiently contestable market retailers lack or are unable to exercise market power. As a result the need for, and hence benefit conferred by, retail price regulation in Australian energy markets is substantially reduced or nonexistent.

We recognise that governments often are concerned that the prices and service offering that result when markets are left to their own devices may not be in the best interest of consumers generally or some group of consumers. As a general rule, price regulation is a very blunt instrument for achieving equity/affordability objectives. It requires the distortion of price signals to all customers even though the focus of government concern is usually a subset of the total customer base. A well-targeted and transparent system of direct subsidies or vouchers to consumers is generally a far more effective and equitable means of achieving social objectives. Even in situations where price regulation is intended to protect entire communities (e.g. in remote areas of Australia), a system of direct subsidies and/or vouchers can be used to achieve social objectives without distorting price signals."

Source ESAA submission to the Owen Inquiry

Morgan Stanley would endorse the above views, and would note a number of instances in overseas markets where retail price caps have distorted the market and ultimately negatively impacted investment incentives.

The difficulties experienced in the Californian electricity market are well know, the role of retail tariff caps is highlighted in Box 33 below.

Box 32: Lessons from Other Markets: Retail Tariff Caps—California

The Californian power crisis in 2001 is well known and multiple factors appear to have combined to contribute to the problems. In commenting here on the retail price caps in California, we are not implying that this was the sole cause of difficulties.

However what is clear is that when wholesale prices climbed, the costs faced by the utilities were well above the regulated price cap that the Pacific Gs & Electricity ("PG&E") and Southern California Edison ("SCE") utilities were able to pass on to customers. Despite appeals to the regulator (CPUC), rates remained frozen. The utilities experienced cash flow difficulties and then ceased paying electricity producers, and the generation companies subsequently shut down their facilities. What started as a price problem had rapidly become a credit problem. Blackouts ensued and the utilities entered bankruptcy. Ultimately the state had to take over the responsibility of purchasing power, which then led to the crisis progressively being resolved as the State's balance sheet (i.e. taxpayers) underwrite ongoing credit risk.

Notably one of the utilities, San Diego Gas and Electricity ("SDG&E"), did not get caught in financial distress. This utility's rates were adjusted monthly according to wholesale prices. A subsequent price cap that was imposed also created a tracking account whereby it was clear that shortfalls in the tracking account were to eventually be borne by ratepayers—over time.

Source Morgan Stanley research

Morgan Stanley also notes the recent IPART tariff determination, to apply from 2007 to 2010. IPART's tariff determination reflects a revised methodology to determining retail tariffs, which will result in real increases in regulated tariffs to levels that are more cost-reflective and should provide the private sector with greater confidence to invest. The revised methodology is set out in Table 24 below.

4.8 Commercially Determined Prices (cont'd)

Table 24: New Approach to Retail Price Regulation

Previous Approach	2007–2010 Determination
• Low cost-to-serve, based on incumbent retailer costs	• Higher cost-to-serve based on new entrant retailer costs
• No allowance for hedging costs, due to ETEF	• Allowance for hedging and transaction costs
• Low net margin reflecting limited risk exposure of retailers under ETEF	• Removal of ETEF result in higher net margin to compensate for additional risk
• Explicit focus on impact on customers	• Explicit focus on cost reflectivity
→ Increase in tariffs/gross margins	
→ Increase in competition and churn	

Source Morgan Stanley research

Notwithstanding the real increases in regulated retail tariffs that will occur over the next three years, whilst retail tariffs are subject to regulatory caps there is a risk that market prices will not adequately respond to supply and demand pressures and generate the right price signals for new investment.

4.8.3 The Electricity Tariff Equalisation Fund

The Electricity Tariff Equalisation Fund was introduced by the NSW Government as a transitional mechanism to manage the risk that government-owned electricity retailers are exposed to in purchasing wholesale electricity in a volatile market to supply default customers at regulated prices.

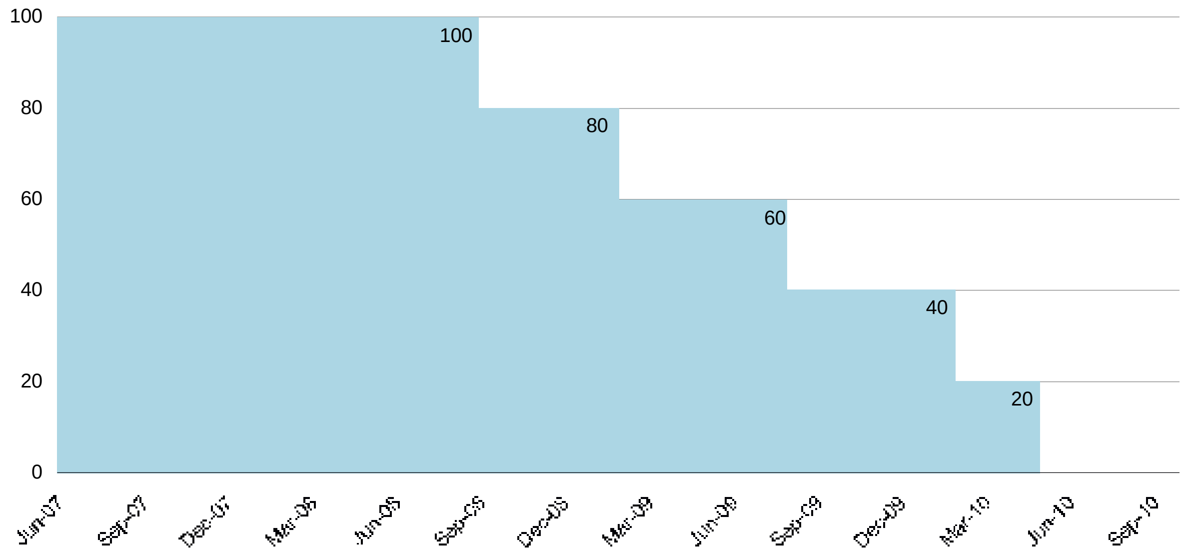
ETEF has been successful in meeting its risk management objective, however, ETEF has been subject to a number of a number of criticisms regarding its impact on the market, including:

- Its impact on contract market liquidity, by having a material portion of NSW electricity demand managed "off-market" via a legislative fund
- Its impact on NSW generator bidding behaviour, due to NSW generators' exposure to the risk of "topping up" the fund once fund balances fall below zero
- Its impact on incentives for investment, particularly in peaking generation, as NSW retailers have no incentive to either invest in generation, or enter into long-term contracts with other parties investing in generation, as they are not exposed to the risk of franchise load purchases

A number of these issues were highlighted in the NSW Government's Energy Directions Green Paper (December 2004), and the Government subsequently announced its decision to progressively wind-down ETEF in accordance with the timetable in Exhibit 42 below.

4.8 Commercially Determined Prices (cont'd)

Exhibit 42: Planned Phase-Out of ETEF
% of Regulated Load Covered by ETEF



Sources ETEF Payment Rules, NSW Treasury

The removal of ETEF in accordance with the communicated timetable should eliminate the potentially market-distorting impacts of ETEF, increasing contract market liquidity and incentives for investment, and is considered by Morgan Stanley to be an important precondition to private investment in generation.

4.8.4 Electricity Trading and Bidding Behaviour by SOCs

Investment behaviour by the SOCs could deter new investment behaviour, as discussed earlier in this report. A distinct issue is the ongoing commercial behaviour of the SOCs in the marketplace.

Private sector perceptions about the commerciality of bidding behaviour by government-owned businesses is mixed:

- Under normal circumstances, most participants regarded the SOCs as behaving commercially according to their circumstances. Some parties contend that ETEF provided certain incentives and that the generator SOC behaviour reflected those incentives
- In times of market stress and tight supply—demand balances, there was concern that influence from the Government as shareholder direct or tacit, may occur

There is limited evidence of noncommercial behaviour (meaning bidding too low) in New South Wales that we are aware of. In fact it appears the Government-owned generators having a track record of exploiting commercial bidding opportunities, within the constraints of the National Electricity Rules.

For example, the AER's review of high priced events in the NEM between 12 June and 28 June 2007 noted that a tight supply and demand balance had emerged due to record demand driven by cold

4.8 Commercially Determined Prices (cont’d)

weather, and supply constraints due to the impact of the drought on available capacity in Queensland, NSW and Snowy, and flooding in the Hunter Valley.

Due to this confluence of events, opportunities arose for generators to modify their bidding practices to realise higher prices. The AER noted the following:

“The effect of the tight supply-demand balance on market outcomes appears to have been exacerbated by the day ahead bidding practices of generators, particularly Macquarie Generation. Macquarie Generation repriced capacity into higher price bands during evening peaks every day in June. These practices did not involve a breach of the National Electricity Rules.” [(1)]

It is simply not possible for Morgan Stanley to verify the presence or absence of non-commercial behaviour. The difficulty faced by Government as shareholder is well founded in that its very presence creates perceptions of noncommercial behaviour, regardless of whether these views are completely unfounded.

Notes

1. AER, Prices above $5,000 per megawatt hour in the NEM—12 June 2007—28 June 2007.

Private Sector Investment: AGL Energy’s Somerton Power Station in Victoria
Photo courtesy AGL Energy

Built in 2002, the Somerton Power Station provides 150MW of gas fired generation and is located close to the major load centre in Victoria, being in the industrial suburbs of Melbourne. Four 37.5MW gas turbines make up the generation capacity, reducing the impact of start failure. The capacity of Somerton is used to meet AGL Energy's Victorian retail customer demand.

Section 5
Options for Government

5.1 Linking Investment Conditions and Options

The dominant objective in assessing options for Government is the facilitation of new private sector investment in generation. Commercial conditions for investment are not being met at present. The private sector does not currently have access to the best business models for new generation investment in NSW, with:

- Limited exposure to existing generation, from which to expand their portfolios
- Limited exposure to retail operations

It does not automatically follow that no party will ever invest in generation in NSW under the status quo. There have been instances of private generation investment in the past, and it is possible that the private sector will invest in the future.

However, Morgan Stanley firmly believes that the government can only have a very low level of confidence that the private sector will invest under the status quo. In particular, the private sector is highly unlikely to invest the significant capital required for emerging baseload needs without access to more sustainable models for investment and risk management. To ensure private investment under the market-based electricity model, Government needs to remove impediments to private investment, and the creation of a ‘half-market’ of mixed public and private ownership is discouraged.

We therefore conclude that the Government needs to make changes to the ownership and structure of the NSW electricity sector in order, to have a high level of confidence that the private sector will invest, and the detrimental fiscal impacts of a major Government-funded generation investment program are avoided.

To meet market needs and to be of maximum economic benefit to the state, new generation should be both reliable and efficient. This Section 5 outlines the options that maximise the conditions for new private sector investment, to deliver both reliability and efficiency with the greatest confidence. This means identifying those options that will:

- Facilitate interest by a greater rather than lesser number of participants who are potential investors
- Give those participants stronger rather than weaker incentives for investment in all types of new generation
- Result in the maximum diversity of sustainable business models that may create new investment, so that there is maximum competition for new investment

The principles of any options need to be consistent with the conditions described earlier in Section 4, and give the strongest incentives to as many participants as possible as described above. These conditions could be satisfied by a number of options. To refine and clarify the selection of options we have first outlined the principles for action in Table 25 below.

5.1 Linking Investment Conditions and Options (cont'd)

Table 25: Conditions, Principles for Change and Options

Condition	Principles for Change to Maximise New Private Sector Investment	Options Most Consistent with These Principles and the Private Sector Investment Objective
Market Need (Section 4.2)	Government should avoid/divest those roles where it is a participant in the competitive electricity market, and provide the private sector with the appropriate economic incentives to invest, by allowing the private sector to acquire the whole of its retail and generation businesses. Having provided the appropriate exposures Government should as far as possible avoid intervening let the market decide how and when it invests. This means avoiding: • Ongoing ownership of competitive electricity business • Creating businesses owned in joint venture between the Government and the private sector • Creating Government-initiated development joint ventures • Future Government investment in power stations that compete for dispatch in the NEM and hence displace normal private sector investment • Imposing development obligations or the like on the private sector buyers	Transfer the State's interests in its retail and generation businesses to the private sector. The State should encourage the development of demand side response to electricity prices, so as to improve the functioning of the demand side of the market in NSW and improve reliability and efficiency. Government will not allow NSW businesses and residences to suffer from blackouts and supply shortfalls. The NEM is already designed with the objective of achieving a stated reliability threshold. If the Government is not satisfied with the pace of new power station development, the best way to achieve additional reliability without diminishing private sector investment incentives is to consider measures solely focused on enhancing reliability. Such an approach would enhance reliability (at additional cost) but not result in Government investment competing in the NEM.
Access to stable revenue streams (Section 4.3)	Government should transfer to the private sector all of those businesses which will enable the private sector to assemble a range of sustainable business models.	Transfer the State's interests in its retail and generation businesses to the private sector.
Access to fuel and other inputs (Section 4.4)	The Government should avoid mandating fuel or technology choices for future generation. Government should also avoid fuel or technology specific policy settings. Reliability and efficiency in NSW would be best served by open competition between gas and coal (and other fuels and technologies) for future generation.	Closely monitor progress in national gas and electricity market reform and the rules for new transmission development for both gas and electricity.
Site access and planning (Section 4.5)	The Government should closely monitor the progress of reforms to development approval processes to ensure proposals for new power development (and associated fuel and infrastructure) are being considered expeditiously. The Government should transfer to the private sector all of those current power development sites that it has in its portfolio, and should develop those sites to a higher level of readiness in the time period leading up to a sale process, so that future development timeframes and obstacles are reduced.	Closely monitor progress of development approvals, and if progress is unsatisfactory, make further changes to streamline consideration of applications. Transfer all of the State's interests in power development sites to the private sector.
Access to capital (Section 4.6)	Government should avoid/divest those roles where it competes with the private sector and where public sector capital displaces private sector capital. Government should avoid policy settings which may limit revenue in the sector such as retail price caps, since these may be a barrier to private capital formation.	Transfer all of the State's interests in its retail and generation businesses to the private sector. Support the planned review of the effectiveness of retail competition and the removal of caps if that is the finding of the AEMC. Implement social policy support for electricity affordability via nonprice measures (such as targeted rebates) rather than price caps.
Stable policy environment (Section 4.7)	Contribute to policy stability and certainty by making clear announcements on the policy regime to apply for the next five years through to 2012 and the expected latest start for a national emissions regime. Government should avoid/divest those roles where its role as a regulator and policy makes conflicts with its	Government should: • Consider the implementation of NRET in the face of an emerging national emissions scheme • Bring forward consultation on the rules for transition of State-based schemes to the national trading platform

5.1 Linking Investment Conditions and Options (cont'd)

Table 25: Conditions, Principles for Change and Options

Condition	Principles for Change to Maximise New Private Sector Investment	Options Most Consistent with These Principles and the Private Sector Investment Objective
	role as an operator of active businesses. Government should avoid/divest those businesses where there is a perception that they might potentially act to meet noncommercial objectives.	• Encourage the Commonwealth to bring forward clarity on emission rules • Specifically rule out underwriting project-specific emissions risk Transfer the entirety of the State's interests in all of its retail and generation businesses and development sites to the private sector to remove the current uncertainty about the government's future ownership and investment intentions.
Commercially determined electricity prices free of government intervention (Section 4.8)	Avoid devices which act to distort or cap prices at the retail or wholesale level. Avoid transaction designs that do not lead to commercially conventional business models that would not otherwise arise.	Support the planned review of the effectiveness of retail competition and the removal of caps if that is the finding of the AEMC. Transfer all of the State's interests in its retail and generation businesses and greenfield development sites to the private sector. Implement nonprice based social policy support for electricity affordability. Implement announced wind-down of ETEF. The Government should encourage the development of demand side response to electricity prices, so as to improve the functioning of the demand side of the market in NSW and improve responsiveness to price signals.

The remainder of this Section 5 describes the various options consistent with the principles outlined above, both policy conditions (which are largely in place, with the notable exception of the emissions regime) and commercial conditions (which are not in place).

The description of these options goes to the fundamental decisions required by Government to bring into being the right conditions for private sector investment in the state, which is the dominant objective of this review. Except where specifically noted in the following subsections, for the most part it is beyond the scope of this report to go into detail on implementation considerations such as how businesses might be sold or best packaged for sale, and consequences of different implementation options. In any event such detail would not be appropriate in a public report of this nature.

Options that do not transfer economic exposure to generation and retail businesses to the private sector will not achieve the private sector investment conditions articulated earlier in this report. As such, options that involve the status quo or reorganised businesses under continuing Government ownership have not been considered beyond our assessment of whether these would achieve the appropriate conditions for private sector investment, which they do not.

We also recognise that that there is a limited period of time in which to act so that the Government can be confident that the next tranche of generation will be funded by the private sector. Preparation for implementation will take time and no transactions will be feasible in the balance of 2007. We strongly recommend that the Government commence preparation for sale during the balance of 2007 and implement its preferred course of action during 2008.

5.2 Addressing the Commercial Conditions: Retail-Led Investment

Providing the appropriate commercial incentives for retail-led investment involves significantly increasing the private sector's economic exposure to the retail load in New South Wales. As stated in Section 5.1 the best way to achieve this (and to crystallise value to the state in the process) is to sell the retail operations of the State-owned corporations to the private sector:

- A sale of the retail operations of Energy Australia, Country Energy and Integral Energy would effectively accelerate the private sector's exposure to the NSW retail load, by immediately transferring customers to private sector retailers rather than allowing customers to churn to the private sector over time, as is likely to happen under the status quo
- Compared to retention, a sale is likely to be value-accretive for the State, as acquirers would have access to greater scale, geographic diversity and vertical integration benefits that are not available to the State-owned retail businesses under their current ownership arrangements. In a competitive auction process, purchasers of these businesses will factor part of this additional value into the prices they bid, thereby transferring a portion of this value to the State
- As noted in Section 4, companies that are exposed to a critical mass of retail load have strong incentives to invest in new generation infrastructure as part of their overall risk management strategy
- Morgan Stanley is confident (subject to requisite policy conditions being met) that the purchasers of the retail operations in NSW will invest in new generation in the medium-term as part of their strategy of hedging their retail exposure in NSW. As a recent example of this behaviour, shortly after acquiring the Sun Retail business from the Queensland Government, Origin Energy announced its commitment to construct the 630 MW gas-fired generator at Braemar in Queensland
- The acquirers of the retail businesses will have particularly strong commercial incentives to invest in flexible, gas-fired generation in NSW, as this technology is well suited to hedging the volatility of a retail load exposure

Other inferior options open to the Government to facilitate an increase in the private sector's exposure to retail include:

- Simply allowing the private sector to increase its retail exposure over time, by "churning" customers from Government-owned retailers in the normal course of the competitive retail market, and allowing the SOC retailers to go into a long, slow decline
- Enter into long-term retail risk management contracts (such as retail trading or "re-selling" arrangements), under which the private sector assumes the wholesale market risk of the State-owned corporations' retail customers

We do not recommend that the government rely on private retailers developing their retail exposure in NSW over time by way of churning retail customers from government retailers for the following reasons:

- Natural market churn is unlikely to give the private sector a critical mass of retail load exposure quickly enough to drive them to invest in new generation in the timeframe required
- The rate and pace of churn is uncertain, and inevitably a material part of the customer base will not churn for any number of reasons

5.2 Addressing the Commercial Conditions: Retail-Led Investment (cont'd)

- It is likely to result in a significant loss of value for the State, without any offsetting benefit
- Allowing the retail businesses to slowly decline will hardly create a positive environment for employees
- Churning customers only facilitates retail entry and does nothing for generator developers who do not want to be retailers

Retail trading models have been previously examined (refer to the Electricity Trading Risk Management Proposal for NSW Electricity Businesses released in 2004) and were rejected as suboptimal on a number of grounds. Models that incorporate "reselling" of electricity by retail SOCs in a contractual joint venture where the private sector takes all electricity market risk have also been proposed. These reselling models have been proposed in an environment where a full sale of the retail business may not have been a step that Government was willing to make. There is little empirical support for such models in the market if a sale of retail is available—such models have not developed organically in other electricity markets—and any dilution of full ownership may also dilute the incentives for investment. As stated in Section 5.1 above, in order to maximise the prospects for investment we do not believe the Government should contemplate options that do not result in commercially conventional business models.

5.3 Addressing the Commercial Conditions: Generator-Led Investment

While new owners of the NSW retail businesses may invest, or help to underwrite investment in, new baseload generation, they do not necessarily have undiluted incentives to invest in baseload, compared to peak-intermediate generation, for the following reasons:

- A retailers' primary interest is in ensuring that their own retail exposure is hedged, and will generally adopt a matched position of seeking balance between retail and generation. By way of example, the generation asset swap between AGL and TRUenergy this year in part reflected each parties' interest in achieving better portfolio balance
- Retailers have typically invested in flexible, gas-fired peaking and intermediate generation as this technology provides risk management benefits during times of peak demand when retailers are most exposed to price volatility. Retailers do not appear to have placed the same strategic premium on ownership of baseload generation, although as demonstrated earlier in this report the market has had a sufficient supply of baseload in most markets, and the need to hedge energy supply risks in this way was modest at best
- A retailer would not appear to be strongly incentivised to invest in generation infrastructure which will reduce the average price of electricity across the market (i.e. low SRMC baseload capacity), as this will benefit its competitors and new entrant retailers as well as itself

So, while transferring retail load exposure to the private sector will go a long way towards increasing the probability of private investment in new generation, it is not the optimal solution as it does not provide a full range of commercial incentives to the widest range of participants to invest in all types of generation. In Morgan Stanley's view, for the government to obtain a high level of confidence that the most efficient generation investment will be made by the private sector, it is also necessary to transfer the economic exposure of generation to the private sector. Doing so will facilitate a broader range of business and investment models in NSW, including portfolio generation investment, which will:

- Increase the number of companies operating in the electricity market in NSW
- Increase the competitive dynamic in the market
- Maximise the probability of ongoing, private investment in the most efficient generation technology

Making generation exposure available to the private sector is more likely to attract new entrants than a sale of retail alone. Parties which acquire generation exposure will also provide an additional competitive threat to retailers as they will have the option to forward integrate into electricity retailing and directly compete with incumbent retailers, as International Power has done in recent times in Victoria and South Australia.

Generation businesses could be transferred to the private sector via a sale of generation assets, or alternatively, via a long-term lease of Government-owned generation assets which results in operating control being transferred to the private sector.

Both models have been used previously in the NEM, with Victoria opting for a sale model and South Australia opting for long-term lease. Both conventional sales and long-term leases can achieve similar economic outcomes to a sale, so long as a lease is of a sufficiently long-term, and the full risks and responsibilities of operating generation assets are transferred to the private sector. Under the lease model, the Government would retain legal ownership of the generation site and infrastructure but the

5.3 Addressing the Commercial Conditions: Generator-Led Investment (cont'd)

private sector would take full economic risk and reward for operating and managing the power station going forward.

Combined with a sale of retail operations, this would result in a larger number of parties with more diverse incentives to invest in all types of generation (peaking, intermediate and baseload). This outcome is more consistent with the objective of maximising the likelihood of private investment in generation than a sale of retail operations alone, which is likely to result in a more limited set of investment incentives applying to a smaller number of parties.

Such an outcome is likely to be in the long-term interests of electricity consumers in NSW, as it is likely to lead to more efficient generation investment and more competitive power prices, compared to the status quo or a sale of retail only. This may lead to greater economic development opportunities in NSW, and greater employment in energy-intensive industries.

Other models such as generator trading rights have been considered to transfer the economic exposure of generation to the private sector but have been assessed as inferior. Generator trading models have been previously examined (refer to the Electricity Trading Risk Management Proposal for NSW Electricity Businesses released in 2004) and rejected. Government determined that it did not want to proceed with the model because of the complexity of risk allocation issues that the model involved. In particular, the model involves a separation of the role of operating power stations from the trading of the output of power stations, which requires complex availability and force majeure regimes.

These models could partially transfer economic exposure to generation, but are considerably less likely than other models—such as lease or sale—to attract a broader range of parties to the NSW electricity market. These instruments are trading or dispatch instruments and are not economically equivalent to full generation ownership. The most likely counter parties to such contracts would be the parties that acquire the NSW retail businesses, and as such these are less likely to introduce any new business models or a diverse range of players.

5.4 IPO Alternatives

Trade sales are one way to transfer the retail and generation businesses to the private sector. An Initial Public Offering ("IPO") is an alternative way in which to transfer economic ownership to the private sector, and essentially accesses capital markets directly to fund the acquisition rather than indirectly as would occur with assets acquired by trade buyers. IPO alternatives could be considered by Government alongside trade sale options for the remainder of the portfolio.

In the timeframe for action, it is impractical to launch multiple IPOs of similar businesses that would compete for investor interest and capital. Staggering IPOs over a period of time would delay execution and not bring forward investment decisions by the private sector.

In our view an IPO of a retail-only business is not saleable to the equity markets due to the high risk, low margin nature of unhedged electricity retailing and any such entity is highly unlikely to achieve an investment grade credit rating which will make its commercial operations difficult and which would adversely affect investor perceptions. Accordingly any IPO vehicle would need to include meaningful interests in generation assets.

5.5 Addressing the Policy Conditions

In most instances, the necessary policy conditions for private investment are either already in place, or are in the process of being implemented. Accordingly, most of Morgan Stanley's policy recommendations involve the Government keeping to the course of action which it has previously embarked upon.

The key exception to this is carbon policy uncertainty, which we recommend the NSW Government encourage the Commonwealth to resolve as soon as possible.

5.5.1 Timely and Predictable Environmental Planning Processes

As noted in Section 4.5, the Government has recently progressed amendments to environmental planning and assessment arrangements in NSW which should allow more streamlined assessment of environmental impacts of generation developments.

We recommend the Government monitors the implementation of these arrangements, to ensure the market is able to progress development approval over a number of generation sites to ensure that timely investment can proceed in response to market conditions.

While we recognise that environmental planning processes have a legitimate policy role in mitigating the environmental impacts of generation infrastructure, it is important that they are coordinated with other regulatory and market mechanisms in order to avoid duplication and delay. As has been discussed at length in this report, the National Electricity Market provides strong commercial drivers for investment in appropriate new generation technology at the appropriate time. Accordingly, planning authorities need not concern themselves with detailed analysis of whether a new generation investment is required—the fact that a commercial party is prepared to take the risk on new generation investment should be a matter for that party alone.

Similarly, planning authorities should avoid prescribing environmental criteria at an individual plant level to control environmental externalities that are being managed at a sectoral level. For example,

5.5 Addressing the Policy Conditions (cont'd)

there is not a strong case for greenhouse emissions criteria being applied at an individual plant level when there is a market-based scheme for limiting emissions at a sector level (e.g. the NSW Greenhouse Gas Abatement Scheme, or the proposed National Emissions Trading Scheme). The inclusion of such criteria in an environmental planning process not only leads to unnecessary duplication, for no incremental environmental benefit, but creates delay and additional regulatory risk for power station investors which could have the effect of deterring private sector investment.

As we have noted elsewhere, delays in environmental approvals have been a factor in supply security issues in other jurisdictions (e.g. California), and uncertain, untimely development approval processes can be a significant deterrent to investment.

5.5.2 Access to Fuel

We do not see a strong need for the government take any particular action to enhance the private sector's access to fuel supply for power generation, but rather recommend the Government allows free and open competition between all fuel types (particularly gas and coal), and allows market conditions to determine the mix of fuels that supply future generation. Broad-based carbon trading will result in investors factoring the carbon intensity of different fuel types into their investment decision-making, and the market should bring forward the appropriate technologies to meet medium and long-term emission targets. Robust fuel-on-fuel competition will ensure prices of fuel inputs are kept in check, which will facilitate the most competitive power prices for NSW.

In order to ensure all available fuel types are fully-developed, the government should monitor environmental planning processes for new fuel sources (e.g. coal mines, gas exploration and gas transmission pipelines) to ensure that proposals are assessed and developed in a timely manner.

5.5.3 Cost-Reflective Retail Tariffs

The revised IPART-determined tariffs that apply from 1 July 2007 should move the NSW retail electricity market to a more cost-reflective position, and should ensure that sufficient revenue is available from the market to fund investment in new generation infrastructure.

We also note that recent wholesale prices have been at a level where every retail price cap would result in losses and cash outflows for an unhedged retailer. Should these conditions be maintained, there would need to be a prompt review of tariffs in order to avoid jeopardising the financial viability of retailers.

Whilst retail price caps remain in place, there is a residual risk that they will not reflect market-based cost factors, and will stifle investment. We recommend the Government supports the AEMC review of the effectiveness of retail competition in NSW, planned for 2009 and considers moving to a lighter-handed form of retail price regulation, or removing retail price caps altogether, in the event the AEMC finds that retail competition is effective.

This will reduce regulatory risk for electricity market participants, and will make it more likely that investment in new generation infrastructure will be forthcoming.

5.5.4 Electricity Tariff Equalisation Fund

The sale of the retail operations of Energy Australia, Country Energy and Integral Energy, will permanently transfer the wholesale market risk of supplying electricity to regulated customers to the

5.5 Addressing the Policy Conditions (cont'd)

private sector. To ensure the purchasers have full incentives to manage this risk by investing in generation, the government should implement the phased wind-down of ETEF as previously communicated to the market.

5.5.5 Carbon Policy Uncertainty

Unlike other policy conditions, the Government has no ability to directly resolve the current carbon policy uncertainty, which is a Commonwealth responsibility. While the Government could contractually underwrite the carbon risk of new generation projects until such time as carbon policy uncertainty is resolved, Morgan Stanley would not recommend this approach as it would result in the State of NSW assuming potentially significant financial exposure to new generation investment, would result in the government "picking winners" by determining which new generation investment it would underwrite, and could also negatively impact on those parties who invest in "good faith" in less carbon-intensive generation in the expectation that it will be economically advantaged under a future carbon trading scheme. There is a real risk that current investment plans could be deferred if investors face the risk that subsequent plant may be economically advantaged by Government underwriting emissions risks.

Instead, the Government should encourage the Commonwealth to determine and communicate to the market the key parameters of its proposed carbon trading scheme, in advance of the resolution of more detailed design issues. The key parameters that Morgan Stanley regards as most critical to investment decision-making are:

- The medium-term (e.g. 2020) aggregate emissions target which a carbon trading scheme will seek to achieve
- Which industries will be included or excluded from the scheme
- Transition rules from existing state based schemes to a national scheme
- The point in time after which new generation developments will not receive a free permit allocation
- The penalty for noncompliance which will effectively "cap" the price of carbon

While further details would be welcome, clarity on the above points should provide the private sector with a sufficient level of certainty to model the medium-term impacts of a carbon trading scheme, and likely carbon prices, and should allow it to make more informed investment decisions.

Clarity on the carbon scheme is particularly relevant for baseload investment economics. Peak investment is unlikely to be deterred by carbon issues, given almost any level of carbon penalty is worth paying if a peaking generator can capture price peaks of several hundred to several thousand dollars per MWh. As we have noted in Section 4, forward electricity prices will be affected by carbon price expectations. If clarity on carbon settings is provided late, this will affect trading and price expectations in the electricity market.

We understand the Government is considering the adoption of the NRET scheme as an extension of the MRET scheme. The introduction of the NRET scheme should be considered in light of (i) the potential 2010–2012 introduction of a national emissions trading scheme and (ii) NSW's need for new investment in reliable capacity. The introduction of NRET, assuming it brings on investment in renewables like wind, will defer the installation of conventional baseload plant as additional energy will be generated from the renewable sources. In turn for reliability to be maintained, additional gas-fired peaking may be required, depending on the reliability of the renewable generation installed under

5.5 Addressing the Policy Conditions (cont'd)

NRET. In the context of a national emissions trading scheme, incentive schemes for specific generation technologies are not required in order to reduce sector-wide carbon emissions.

5.5.6 Government Investment Intentions

The private sector will require confidence that the Government does not intend to intervene in the market, particularly via government-supported investment which can negatively impact wholesale electricity prices. While the Government cannot walk away from its responsibility to ensure the electricity market works effectively in providing sufficient generation capacity to secure supply (much as the Government has a "last resort" role in ensuring the effective provision of other essential services), it does not necessarily follow that the Government needs to intervene by being an investor in the market.

Instead, the Government should ensure that the supply reliability institutions built into the NEM, such as the Reliability Panel and NEMMCO's Reserve Trader function are effective in securing the ongoing reliability of supply.

5.5.7 Demand Side Response

The demand side of the market could play an important and greater role in enhancing system reliability in periods of high stress and high wholesale price. Overall, greater interaction of demand with supply can be expected to improve the functioning of the NEM.

Deferring demand can:

- Reduce the cost of energy and improve reliability by shaving peaks
- Pro actively limit long-term increases in electricity prices by making the electricity market more efficient
- Provide a genuine market-based indication of the price of reliability
- Relieve stress on electricity networks at times of extreme peaks, creating greater supply reliability and more efficient capital investment
- Reduce emissions
- Reduce water consumption
- Reduce the need to build more generators and network that is used only to meet the demand peaks

Government can play a role in enabling greater demand side responsiveness through:

- Third-party access regimes, for example to demand-responsive technologies installed on electricity networks
- Recognising costs of demand side response in regulatory tariffs for distribution and transmission networks, as an alternative to increased capital and operating expenditure
- Allowing retail tariff structures that create incentives for homeowners to manage their time of use

5.6 Consequences of No Action and Retention of Status Quo

If the Government does not act to reform the current electricity industry structure:

- It will have no choice but to pursue new investment in generation, not only baseload generation but likely also peak generation. In the absence of change there is no reason to expect that the Government would not repeat the experience where the Government felt it needed to proceed with the Colongra plant to ensure new investment. In the absence of genuine reform in NSW the private sector is likely to look elsewhere for investment opportunities
- It will have to choose between competing generation projects proposed by competing generator and retail SOCs. Under private ownership multiple projects might proceed as private sector participants seek to compete with each other. However funding multiple competing project seems an irrational outcome under the current industry sector where the Government is the sole shareholder, and endorsing competing projects that each lowered the returns of the other would be a waste of taxpayers money. In such an environment of Government selected projects and fiscal restraint less rather than more generation development might actually occur under Government ownership than would be expected in private ownership, and less diversity of plant may also result
- The Government will allocate capital to competitive generation projects which will reduce the capital available for other social programs and investment, in the absence of further borrowings
- The values of the retail businesses in their current form will continue to slowly erode over time and may become negative
- The Government will continue to bear all the emissions risk in the electricity sector as it does now
- Government may be compelled to invest substantial capital to improve the emissions footprint of its generation fleet over time, in addition to normal ongoing stay in business capital expenditure. This may have a compounding effect on the State funding in the electricity sector. Emissions-related development (such as pilot tests for carbon capture) may reduce the net sent out energy of the existing plant, as the capture process necessarily consumes some energy. The loss of energy from the existing plant may then require further Government-funded capital expenditure on additional plant to compensate

5.7 Consequences of Status Quo for Retail SOCs

Electricity retailing businesses have few physical assets, are essentially financial intermediaries, and largely comprise:

- The customer accounts themselves, which may be covered by contestable contracts and market-based tariffs or by regulated supply arrangements and tariffs
- Back office systems that support customer account management, billing and the like
- Contact centres
- Risk management activities, such as procurement and hedging of conventional electricity and ‘green’ products

It is important to note that under full retail contestability, the retail SOCs compete with private sector retailers and customers can ‘churn’ between different retailers the same way that telephone customers can move between different providers of telephony services. Under full retail contestability, the customers of the SOCs can already move to other providers—a sale of the retail businesses simply brings forward to a single point in time what could already occur under churn and crystallises value in the customer base.

As natural market churn takes place, we would expect the revenue base of the Government-owned retailers will decline in NSW, as they lose customers to competing privately-owned retailers. This is a natural expectation given the current initial very high market share of the SOCs—it is relatively easy to lose customers in NSW from their current market position but harder to grow total market share back close to 100%. While this loss of customers can be offset to some degree by winning customers elsewhere, doing so involves:

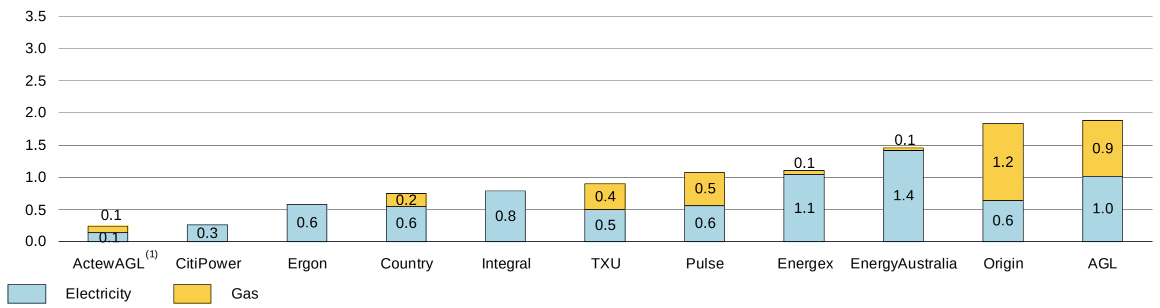
- Government-owned retailers competing against one another e.g. Energy Australia seeking to win Country Energy’s customers and vice versa, which is (at best) value neutral for the Government, and more likely to be value-negative, as value is shifted from government retailers to customers, in the form of discounts
- Government-owned retailers competing for customers inter-state, which involves them taking wholesale market risk in other states, and competing against larger incumbents in those states who have more advanced, vertically-integrated business models, with direct access to generation and upstream gas. In competing in interstate markets, the SOC retailers will increasing be buying wholesale energy from their vertically integrated retail competitors, and it would not be rational in these circumstances to expect the SOCs to be able to make superior risk-adjusted returns over time

Exhibit 43 and 44 demonstrate:

- The number of major retailers in the NEM has reduced in the last five years, largely due to acquisitions of smaller retailers (Citipower, Energex and Pulse) by larger retailers (AGL and Origin)
- While AGL and Origin have both significantly expanded their customer bases over the last five years, the NSW retailers have not materially grown over the same period
- The two largest retailers, Origin and AGL are both bigger than the largest NSW retailer (Energy Australia) and more than three times the size of the two smaller NSW retailers (Integral Energy and Country Energy)
- The gap between the largest retailers and the SOCs has grown substantially

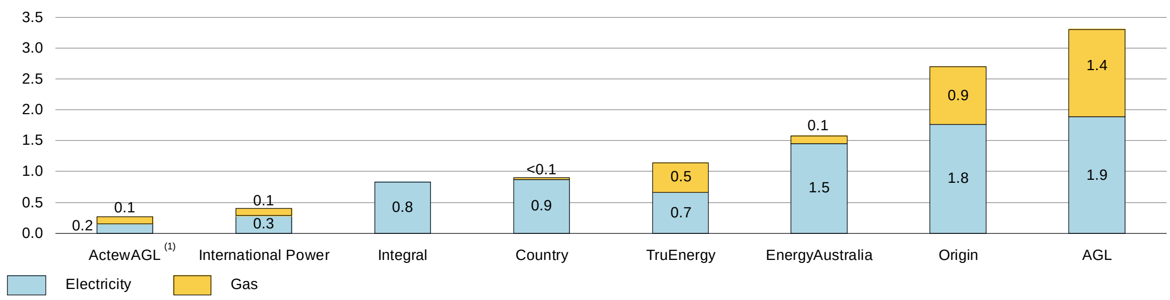
5.7 Consequences of Status Quo for Retail SOCs (cont'd)

Exhibit 43: 2002 Customer Numbers—More Competitors of More Even Scale
MM



Source Company Reports, Broker Reports, Submissions to the Owen Inquiry

Exhibit 44: Customer Numbers Today—Fewer Competitors, Largest Players Have Become Larger
MM



Source Company Reports, Broker Reports, Submissions to the Owen Inquiry

Notes

1. AGL has a 50% interest and manages the wholesale market risk for the business

There are significant economies of scale and scope in energy retailing, due to:

- The relatively high fixed cost component of servicing customers (e.g. running billing systems, operating call centres, trading electricity)
- The risk management benefits of having geographically diverse retail loads, as weather conditions (which have a significant impact on electricity demand and prices) are likely to be geographically concentrated

Consequently, larger, geographically diverse retailers have significant cost advantages relative to smaller, geographically concentrated retailers.

In 2007, two of the three NSW Government-owned retailers are now subscale relative to their private sector counterparts. Integral Energy and Country Energy both have ~700,000–800,000 customers, which is less than a third of the customers of the two largest private retailers, Origin Energy and AGL Energy. They operate in relatively concentrated geographies, with the majority of customers located within their network areas, compared to the largest private retailers who have retail customers across all states in the NEM.

5.7 Consequences of Status Quo for Retail SOCs (cont'd)

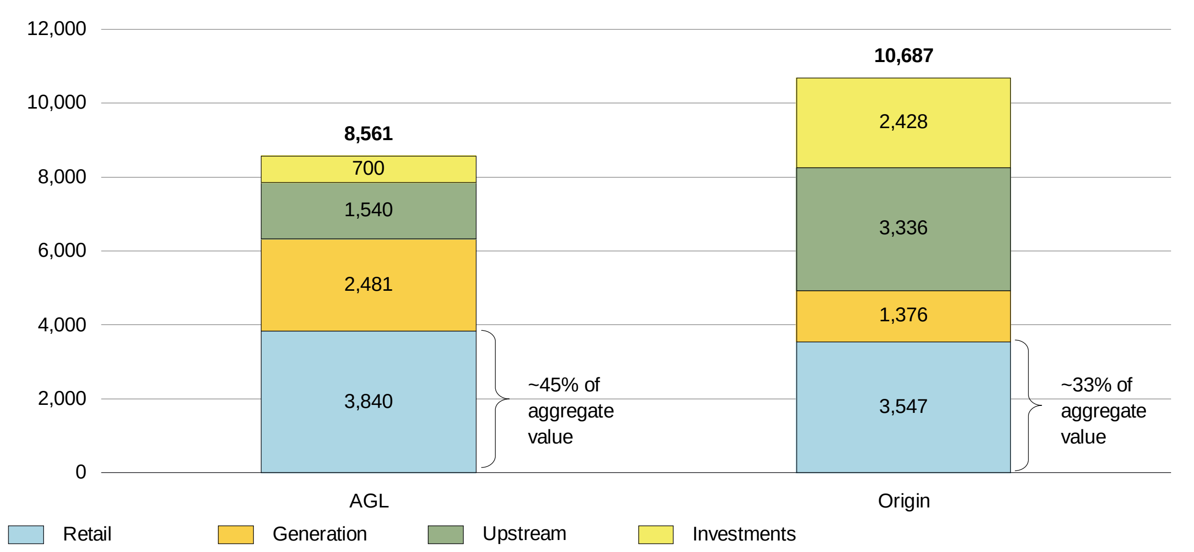
In their current form and size, Integral Energy and Country Energy cannot be expected to have access to these economies of scope and scale to maintain and grow their existing businesses and earn competitive risk adjusted returns over time.

Energy Australia, in contrast, has a larger customer base of approximately 1.5MM customers with a growing presence in gas retailing, and this scale means it is better-positioned to compete against the private sector. However, despite its greater size and dual fuel capabilities EnergyAustralia's business model is essentially the same as that of Integral Energy and Country Energy, and currently excludes vertical integration with generation and upstream gas.

The most likely scenario for the retail SOCs is for them to be net losers of retail customers, as larger private competitors, with access to national economies of scale and scope churn their customers away. None of the businesses are well-resourced to offset these losses with profitable customer gains inter-state. Morgan Stanley's view is that in their current form these businesses are likely to lose significant value over time, as their revenue base erodes but they retain the fixed costs of operating retail businesses.

As an indication of the significance of the nonretail businesses to the total operations of AGL Energy and Origin Energy, Exhibit 45 below shows the "sum-of-the-parts" valuations of these businesses estimated by Morgan Stanley Equity Research.

Exhibit 45: AGL and Origin Energy Value Breakdown
Estimated Value Break-Down



Source Morgan Stanley Equity Research

5.7 Consequences of Status Quo for Retail SOCs (cont'd)

Both AGL and Origin Energy have less than 50% of their business value in retail customers—the balance is comprised of upstream power generation and gas assets, which support the retail exposure, along with investment in related ventures. (1)

For the retail SOCs to compete on a more level footing with their private sector counterparts, and putting aside issues of scale for the smaller retail SOCs, they would need to radically change their business models. This is likely to require significant capital investment (potentially in the order of $3Bn–$4Bn), for example:

- Developing an upstream gas equity position is likely to involve investment of at least $1Bn–$2Bn, by either acquiring an existing upstream gas company, or by investing in gas exploration
- Developing interstate generation positions is likely to cost at least $1Bn (e.g. acquisition/ development of open-cycle gas power stations), but a more optimal generation position (e.g. with combined cycle gas or baseload generation) would require at least a further $1Bn in capital investment

Even if the Government wanted to invest these funds to develop these businesses, there is no guarantee that assets would be available. Gas assets are relatively scarce and acquisitions are likely to be contested.

This capital expenditure is not factored in to the current government capital program, and it is in addition to the $7Bn estimate for NSW's likely generation investment needs over the next decade. Consequently, the government would need to seriously consider the fiscal implications of investing this additional capital in order to improve the competitive position of its retail businesses. Available assets will be scarce and will be the subject of competitive processes, and even with access to funding it may take several years to improve the competitive positions of the retail SOCs.

In addition to the potential fiscal implications of the investment, the government would also need to consider the additional risk exposure it would be assuming, particularly in areas like gas exploration, development and production in which it has no existing competence.

Notes

1. In AGL's case, the AlintaAGL and ActewAGL joint ventures, and in Origin Energy's case, Contact Energy

5.8 Consequences of Status Quo for Generator SOCs

The generator SOCs would be relatively unaffected by a retention of the status quo, assuming that under the status quo the government continued to fund generation, notwithstanding the impacts this has on the state's fiscal position, and that most new generation was implemented via the generator SOCs. The generation fleet is aging and the oldest station, Munmorah, will either need to be substantially refurbished or withdrawn from service in the next few years. A substantial part of the workforce is within 10 years of retirement age and replenishing this skill base will be an important issue over the next decade.

If the generator SOCs were retained but the Government did not fund additional generation, the generator SOCs would be adversely affected and essentially become amortising assets with limited growth prospects. Their ability to recruit new employees to replace emerging skills gaps would be reduced. Their commercial positions in the wholesale electricity market would become progressively diluted over time, with private sector retailers growing greater countervailing commercial power through developing owned generation. Fuel suppliers could be expected to deal more favourably with parties growing and developing new assets than those with a more limited existence.

Appendix A
Glossary

Glossary

Table 26: Glossary

Term	Meaning
AAA (Credit Rating)	The highest level of credit rating, that generally denotes an extremely strong capacity to meet financial obligations
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Markets Commission
AMPR	Annual Market Performance Review
Baseload Generation	Power plants that are optimised economically and in an engineering sense to a relatively constant, steady and reliable stream of energy
$Bn	Billion dollars
Commonwealth Government	The Government of the Commonwealth of Australia
CPI	Consumer Price Index
DSR	Demand Side Response
ERIG	Energy Reform Implementation Group
ETEF	Electricity Tariff Equalisation Fund
FIRB	Foreign Investment Review Board
FRC	Full Retail Contestability
GEC	Gas Electricity Certificate
Generator SOCs	Macquarie Generation, Delta Electricity, Eraring Energy
GGAS	Greenhouse Gas Reduction Scheme. A NSW Government scheme to reduce greenhouse has emissions associated with the production and use of electricity
GJ	Gigajoule—one billion joules
GST	Goods and Services Tax
IPART	Independent Pricing And Regulatory Tribunal
IPO	Initial Public Offering
J	Joule—the Metric Unit for energy
LEP	Long-Term Energy Procurement Arrangements
LRMC	Long Run Marginal Cost
MCE	Ministerial Council for Energy
MRET	Mandatory Renewable Energy Target
MW	Megawatt = One million watts. A commonly used term to describe power generation capacity or level of demand
MWh	Megawatt Hour = One megawatt hour—the amount of energy produced or consumed over one hour in a system operating at a capacity level of one megawatt. A commonly used term to describe power generation production or consumption
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NRET	NSW Renewable Energy Target
NSW	New South Wales
OTC	Over The Counter
PJ	Petajoule—One million gigajoules
PPA	Power Purchase Agreement
QLD	Queensland
Reliability Panel	The AEMC Reliability Panel
Report	This document
Reserve Trader	The NEMMCO tool to reserve system security, described in Section 3.6

Glossary (cont’d)

Table 26: Glossary

Term	Meaning
Retail SOCs	Energy Australia, Integral Energy, Country Energy
SA	South Australia
Snowy Hydro	Snowy Hydro Limited
SOC	State-Owned Corporation (NSW 100% owned entities only)
SOO	Statement of Opportunities. Issued by NEMMCO annually
SRMC	Short Run Marginal Cost
The Government	The NSW Government
The State	The State of New South Wales
Treasury	NSW Treasury
USE	Unserved Energy—The measure of energy loss adopted by the Reliability Panel in the Reliability Standard
VOLL	Value of Lost Load
VRET	Victorian Renewable Energy Target
WACC	Weighted-Average Cost of Capital
Watt	The basic unit of electrical power. A 60 watt globe uses 60 watts of energy

Appendix B
References and Further Reading

References and Further Reading

Table 27: References and Background Materials

Name	Date of Publication	Author
Australian Focus		
Australian energy national and state projections to 2029-3	2006	ABARE Research Report
Energy in Australia 2006	2007	ABARE
Energy Update 2007	2007	ABARE
SRMC and LRMC of Generators in the NEM	2003	ACIL
Comprehensive Reliability Review, Interim Report	March 2007	AEMC Reliability Panel 2007
Comprehensive Reliability Review, Interim Report,—Appendix 5	March 2007	AEMC Reliability Panel 2007
Annual Electricity Market Performance Review, Reliability and Security, Draft Report	2006	AEMC Reliability Panel
Annual Electricity Market Performance Review, Reliability and Security, Final Report	2005	AEMC Reliability Panel
Reliability Panel, Comprehensive Reliability Review, Issues Paper	May 2006	AEMC
State of the Energy Market 2007	2007	AER
Prices above $5,000 per megawatt hour in the NEM	21-Jun-07–28-Jun-07	AER
Commonwealth Parliament Science and Innovation Committee, Between a rock and a hard place—the science of geosequestration	2007	
The effects of retail price regulation in Australian energy markets	2007	CRA International
Energy Reform: The way forward for Australia, Report to the Council of Australian Governments	2007	Energy Reform Implementation Group
Peter Spearritt, Electricifying Sydney, 100 Years of Energy Australia	2007	George Wilkenfeld
Promoting retail competition and investment in the NSW electricity industry: Regulated electricity retail tariffs and charges for small customers 2007 to 2010, Final Report, 2007	2007	Independent Pricing and Regulatory Tribunal
Does Pacific Power Have Market Power, A Report on the Implications for the National Electricity Market of New South Wales Generation Options	1996	Industry Commission
Energy Generation and Distribution	1991	Industry Commission
Impediments to investment in Australia's energy market: The views of investors	2006	KPMG
Review of Energy Related Financial Markets: Electricity Trading	2007	KPMG
External Market Report High Energy Prices in Tasmania, Victoria and South Australia 23 May 2006	2006	NEMMCO
An introduction to Australias electricity market	2005	NEMMCO
Australia's national electricity market, trading arrangements in the NEM		NEMMCO
Australia's national electricity market, wholesale market operation		NEMMCO
TOWARDS A Truly National and Efficient Electricity Market (Paper Report) 2002	2002	
Prime Ministerial Task Group on Emissions Trading, Report of the Task Group on Emissions Trading	2007	

References and Further Reading (cont'd)

Table 27: References and Background Materials

Name	Date of Publication	Author
Financial performance of government trading enterprises 2004–05 to 2005–06		Productivity Commission
International Focus		
APEC Energy Security and sustainable development through efficiency and diversity: Economic issues in technology R&D, adoption and transfer	2007	ABARE Research Report
Past & Future Dash for Gas in the U.K.	2002	Adrian Smith (PowerGen)
Generation Investments in Restructured Power Systems: Perspectives from the Nordic Power Market (Nord Pool)	2004	Audun Botterud
Capacity Mechanisms: A Necessary Distortion?	2004	Cambridge Energy Research Associates
Focus on Energy: Perspectives from CERAWEEK 2007	2007	Cambridge Energy Research Associates
Generation adequacy and investment incentives in Britain, From the pool to NETA	2004	Cambridge working papers in economics
A regulatory instrument to enhance security of supply in the Spanish wholesale electricity market	2006	Carlos Battle et al
Natalia Fabra, The Spanish Electricity Industry: Plus ça change …	2004	Claude Crampes
EU 25+ Electricity Market Profiles: Current Trends and Future Prospects	2005	Datamonitor
The Energy Challenge, Energy Review Report 2006	2006	Department of Trade and Industry
Meeting The Energy Challenge, A White Paper on Energy	2007	Department of Trade and Industry
Energy Policies of IEA Countries: Australia 2005 Review	2005	International Energy Agency
Energy Policies of IEA Countries: Canada 2004 Review	2004	International Energy Agency
Energy Policies of IEA Countries: Spain 2005 Review	2005	International Energy Agency
Power Generation Investment in Electricity Markets	2003	International Energy Agency
Security of Supply In Electricity Markets: Evidence and Policy Issues	2002	International Energy Agency
California—a market apart?	2004	James Bushnell
Morgan Stanley, Forward Contracts and Capacity Markets: High Powered Incentives or Assets to be Stranded?	2006	Jim Sheffield
Richard Green, Why did British electricity prices fall after 1998?	2005	Joanne Evans
Reliability at any Cost—Risk Management through Contract Technology	2000	John Woodley
Volatility, Capacity and Reliability	2007	John Woodley
National Grid 2007 Seven Year Outlook Statement		
New Zealand Energy Strategy and Related Energy and Climate Change Documents	2007	New Zealand Government
Security of supply April to September 2003, Six month restrospective report 2004	2004	Ofgem
Competitive Electricity Markets and Investment in New Generating Capacity	2006	Paul L. Joskow
Steven Stoft, The Convergence of Market Designs for Adequate Generating Capacity, with Special Attention to the CAISO's Resource Adequacy Problem	2006	Peter Cramton
Energy and efficiency: The changing power climate, Energy, Utilities and Mining global survey 2007	2007	PriceWaterhouseCoopers

References and Further Reading (cont'd)

Table 27: References and Background Materials

Name	Date of Publication	Author
Electricity Investment and Security of Supply in Liberalised Electricity Systems	2005	Richard Meade
Cato Institute, Vertical Integration and the Restructuring of the US Electricity Industry	2006	Robert J Michaels
Allocation of Risk and Development of Capacity Markets		Robert Stoddard (CRA International)
Standard Reviews: United States, The Country Reports		
The Evolution of Capacity Markets in the USA	2007	Tim Mount
Energy Strategies, Dynamics of GB Electricity Generation Investment: Prices, Security of Supply, CO2 Emissions and Policy Options	2007	While Redpoint Energy
On An "Energy Only" Electricity Market Design For Resource Adequacy	2005	William W. Hogan

Further Reading

For further information the NEM, its constituent parts and matters raised in this report we encourage readers to refer to:

Australian Energy Market Commission: www.aemc.gov.au

Australian Energy Regulator: www.aer.gov.au

International Energy Agency: www.iea.org

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

NSW Department of Planning: www.planning.nsw.gov.au

NSW Treasury: www.treasury.nsw.gov.au

Owen Inquiry: www.premiers.nsw.gov.au/WorkAndBusiness/DoingBusinessinNSW/OwenInquiryIntoElectricitySupplyinNSW.htm

Productivity Commission: www.pc.gov.au

Acronyms and Glossary

Acronyms

ABARE	Australian Bureau of Agricultural and Resource Economics
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ANTS	Annual National Transmission Statement
BASIX	Building Sustainability Index
CaO	calcium oxide
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CO_2	carbon dioxide
CO_{2-e}	carbon dioxide equivalent
COAG	Council of Australian Governments
CSG	Coal Seam Gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DNSP	Distribution Network Service Provider
DM	Demand management
DSM	Demand Side Measures
DSP	Demand Side Participation
DSR	Demand Side Response
ESAA	Energy Supply Association of Australia
ETEF	Electricity Tariff Equalisation Fund
ETS	Emissions Trading Scheme
EU	European Union
EUA	European Union Allowance
GEMP	Government Energy Management Policy
GGAS	NSW Greenhouse Gas Reduction Scheme
GJ	gigajoule – one billion joules
GSP	Gross State Product
GWh	gigawatt hours – one billion watt-hours (or 1000 MWh)
HDR	Hot Dry Rocks
IEA	International Energy Agency
IGCC	Integrated Coal Gasification Combined Cycle

IPART	NSW Independent Pricing and Regulatory Tribunal
JPB	Jurisdictional Planning Bodies
kg	kilogram
kV	kilovolt – one thousand volts
kW	kilowatt – one thousand watts
kWh	kilowatt hours – one thousand watt-hours
LDC	Load Duration Curve
LNG	liquefied natural gas
MCE	Ministerial Council on Energy
MEPS	Minimum Energy Performance Standards
MRET	Mandatory Renewable Energy Target
M	million
MW	Megawatt – one million watts (or 1000 kW)
MWh	Megawatt hours – one million watt-hours
NABERS	National Australian Built Environment Rating System
NCOSS	Council of Social Service of New South Wales
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
NETS	National Emissions Trading Scheme
NETT	National Emissions Trading Taskforce
NFEE	National Framework for Energy Efficiency
NGACs	NSW Greenhouse Abatement Certificates
NIEIR	National Institute of Economic and Industry Research
NO_x	nitrogen oxide
NRET	NSW Renewable Energy Target
NTFP	National Transmission Flow Paths
OCGT	Open Cycle Gas Turbine
PCC	Post Combustion Capture
PF	Pulverised Fuel
POE	Probability of Exceedence
PTE	Public Trading Enterprise
QLDGAS	Queensland Gas Scheme
QNI	Queensland to New South Wales Interconnector
RMU	Removal Unit
SOC	State Owned Corporation
SOO	NEMMCO Statement of Opportunities

SO_x	sulphur oxide
t	tonne
TNSP	Transmission Network Service Provider
TOR	Terms of Reference
TOU	time of use
UCC	ultra clean coal
USC	ultra-supercritical coal
USE	Unserved Energy
VoLL	Value of Lost Load
VRET	Victorian Renewable Energy Target

Glossary of Terms

As-generated basis or generator-terminal basis	A measure of electrical power or energy output at the *generator terminals*. This measure includes (in MW) or MWh Electricity *demand* from consumers Electricity lost during *transmission* and *distribution* Generator *auxiliary load* and Generator transformer losses.
Auxiliary loads	The electricity used within the power plant for equipment such as pumps, fans, lighting, etc.
Baseload generator	Generating plant that is normally operated to produce electricity for most hours of the year.
Capacity factor	A capacity factor is the energy generated by a generating unit over a period of time expressed as a proportion of the maximum energy that the unit could generate, if it operated continuously at rated capacity over the same period. It is usually expressed as a percentage. Maximum capacity factor represents the capacity factor that a generating unit is technically capable of operating, taking into account planned and unscheduled outages. Actual capacity factors are always lower than maximum capacity factors due to commercial reasons and/or load curve limitations.
Carbon intensity or emissions intensity	A measure of the amount of carbon dioxide emissions per unit of Gross Domestic Product (GDP) or per unit of energy.
Combined Cycle Gas Turbine (CCGT)	CCGT is a power plant in which a gas turbine generator generates electricity and the waste heat from the gas turbine is used to make steam to generate additional electricity via a steam turbine. This enhances the efficiency of electricity generation.
Committed generation projects	To be considered as committed by NEMMCO, generation projects (including augmentations) must satisfy criteria relating to legal and contractual commitments; planning, construction and other approvals; financing arrangements and construction.
Demand	See Electricity demand (demand)
Demand side management (DSM)	Demand side management is the use of financial incentives, education or other programs to modify the demand for energy.
Demand side participation (DSP)	The situation where consumers reduce their electricity consumption in response to a change in market conditions, such as the spot price of electricity.

De-rating	Reduction in the capacity of a power plant due to technical and other reasons such as restriction on cooling water temperature.
Distribution network	The part of the electricity *network* that conveys and controls the flow of electricity from the transmission network to local customers.
Electrical energy (energy or consumption)	The average electrical power consumed over a defined period multiplied by time duration and measured in GWh (gigawatt hours or 1,000 megawatt hours). Measured on a *sent-out basis*, it includes energy consumed by consumers, and the distribution and transmission losses.
Electricity demand (demand)	The electricity requirement to be met by generating units at a point in time, measured in megawatts (MW). Measured on a *generator-terminal* basis, it includes: The electrical power consumed by consumers; Distribution and transmission losses; and Power station transformer losses and auxiliary loads.
Embedded generation	The output of a generating unit connected directly to a distribution network and with no direct connection to the *transmission network.*
Generation capacity	The maximum amount (in MW) of electricity that a generating unit can produce.
Generation reserve	The amount of *supply* (including available generation capability, demand-side participation and interconnector capability) in excess of the forecast *demand* for a particular period.
Generation reserve margin	Generally accepted international standard, expressed as a percentage, that is the ratio of the: total *nameplate* generation capacity plus interconnector capacity plus interruptible load less the 50% *POE* forecast demand.
Generator	An entity that engages in the activity of owning, controlling or operating a generating system that is connected to, or that otherwise supplies electricity to, a *transmission* or *distribution* system and who is registered by *NEMMCO* as a *generator* under Chapter 2 of the Rules.
Generator terminal	It refers to a point at which the total output from a power generation unit is measured (including losses within the power plant).
Generator-terminal basis	See *As-generated* basis

Interconnector	A *transmission* line or group of transmission lines that connects the *networks* of adjacent *regions*.
Interconnector flow	The quantity of electricity in MW being transmitted by an *interconnector*.
Intermediate load generation	Intermediate power plants have characteristics in between *baseload* and *peaking plants* in terms of *capacity factor*, capital and operating costs.
Jurisdictional planning Body (JPB)	The transmission network service provider responsible for planning a NEM jurisdiction's *transmission network*. In NSW this is TransGrid.
Load	The amount of electrical power delivered at a defined instant at a connection point, or aggregated over a defined set of connection points.
Load duration curve	A load duration curve (LDC) is used in electric power generation to illustrate the relationship between generating capacity requirements and capacity utilization. A LDC is similar to a load curve but the demand data is ordered in descending order of magnitude, rather than chronologically. The LDC curve shows the capacity utilization requirements for each increment of load. The height of each slice is a measure of capacity, and the width of each slice is a measure of the utilization rate or capacity factor. The product of the two is a measure of electrical energy (e.g. kilowatt-hours).
Maximum capacity factor	See *capacity factor*
Maximum demand	The maximum amount of electrical power delivered, or forecast to be delivered in a half hour, for a defined period (day, week, month, season or year).
Minimum generation reserve standard	See *generation reserve margin*
Minimum reserve level	The minimum reserve margin required to meet the *Reliability Standard*. The Reliability Standard states that a region's long-term average unserved energy (USE) must not exceed 0.002% of the energy consumed in that region.
Minimum reserve margins	See *minimum reserve level*.
Ministerial Council on Energy (MCE)	The MCE is the national policy and governance body for the Australian energy market, including for electricity and gas, as outlined in the COAG Australian Energy Market Agreement (AEMA) of 30 June 2004.
Nameplate	The full-load continuous rating of a generator under specified conditions as designated by the manufacturer.
National Electricity Law (NEL)	The NEL is contained in a Schedule to the *National Electricity (South Australia) Act 1996*. It provides for, *inter alia*, third party access to essential electricity infrastructure and regulates wholesale electricity trading through the *NEM*. The NEL is applied as law in each participating jurisdiction of the *NEM* by the application statutes.

National Electricity Market (NEM)	The market to facilitate the wholesale exchange of electricity, operated by *NEMMCO* under the *National Electricity Rules*. The market commenced on 13 December 1998 and now includes Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania.
National Electricity Market Management Company (NEMMCO)	NEMMCO was established in 1996 to: ▪ administer and manage the *NEM* in accordance with the *National Electricity Rules* ▪ develop the market and improve its efficiency ▪ coordinate interregional power system planning.
National Electricity Rules	The rules made under Part 7 of the *National Electricity Law* as amended from time to time in accordance with that Part. They regulate, *inter alia,* wholesale electricity trading through the *NEM*. The rules came into effect on 1 July 2005, replacing the National Electricity Code.
Network	The apparatus, equipment and buildings (e.g. poles and wires) used to convey and control the conveyance of electricity. This applies to both *transmission networks* and *distribution networks*.
Network capability	The capability of a *network* or part of a network to transfer electricity from one location to another.
Network flow	The quantity of electricity (in MW) being transmitted by a *network*.
Network service providers	A person who operates as either a *transmission network* service provider (TSNP) or a *distribution network* service provider (DNSP).
Non-scheduled Generator (non-market)	A generator whose entire electricity output is: Sold directly to a local retailer or customer at the same connection point under a power purchase agreement (not through the *spot market*); and Not scheduled by *NEMMCO* as part of central dispatch.
Open Cycle Gas Turbine (OCGT)	OCGT power plants are the most flexible in terms of adjusting power level, but are also among the most expensive to operate. Therefore they are generally used at times of peak power *demand*.
Peak generator	Generating plant used to supply electricity during peak *demand* times (usually gas-fired or hydro).
Powerlink	The corporation that owns, operates and maintains Queensland's high voltage electricity *transmission network*. Powerlink is owned by the Queensland Government.
Probability of Exceedence (POE) Maximum Demand	The probability, as a percentage, that a *maximum demand* (MD) level will be exceeded (due to, say, weather conditions) in a particular year. For example, for a 10% POE MD for any given season, there is a 10% probability that the corresponding 10% POE projected MD level will be met or exceeded. This means that 10% POE projected MD levels for a given season are expected to be met or exceeded, on average, 1 year in 10.

Proven (1P), Probable (2P) and Possible (3P) reserves	Terms used to refer to the reliability of known or potential mineral reserves. **Proven Reserves (1P)** refers to oil, gas or coal "Reasonably Certain" to be producible using current technology at current prices, with current commercial terms and government consent, also known in the industry as 1P. Some industry specialists refer to this as P90, i.e., having a 90% certainty of being produced. **Probable Reserves (2P)** refers to oil, gas or coal "Reasonably Probable" of being produced using current or likely technology at current prices, with current commercial terms and government consent. Some Industry specialists refer to this as P50, i.e., having a 50% certainty of being produced. This is also known in the industry as 2P or Proven plus probable. **Possible Reserves (3P)** refers to oil, gas or coal "having a chance of being developed under favourable circumstances". Some Industry specialists refer to this as P10, i.e., having a 10% certainty of being produced. This is also known in the industry as 3P or Proven plus probable plus possible.
Region	As recommended by NEMMCO and approved by the AEMC in accordance with Clause 3.5 of the Rules, this is an area served by a particular part of the *transmission network* and containing one or more major load centres, or generation centres, or both.
Regional reference node	The reference point (or designated reference node) for setting a region's *spot price*.
Regulatory Test	The test promulgated by the *AEMC* and carried out by the *AER* to identify the most cost-effective option for supplying electricity to a particular part of the *network*, and deriving from a comparison of alternative projects for generation, or new or expanded interconnection or both.
Reliability (power system)	The measure of the power system's ability to supply adequate power to satisfy *demand*, allowing for unplanned losses of generation capacity.
Reliability of supply	The likelihood of having sufficient capacity (generation or demand side response) to meet *demand* (the consumer load).
Reliability Panel	The panel established by the AEMC under section 38 of the *National Electricity Law*. The role of the Panel is: to monitor, review and report on, in accordance with the *Rules*, the safety, security and reliability of the national electricity system; at the request of the *AEMC*, to provide advice in relation to the safety, security and reliability of the national electricity system; and any other functions or powers conferred on it under the *Law* and the *Rules*.
Reliability Standard	The reliability benchmark set by the *Reliability Panel* that states that, over the long term, the annual customer *demand* at risk of not being supplied can be no more than 0.002% of a region's annual energy consumption.

Reserve	The amount of supply (including available generation capability, *demand-side management* and *interconnector* capability) in excess of the demand forecast for a particular period.
Reserve margin	The difference between *reserve* and the projected *demand* for electricity, where: The reserve margin = (generation capacity + interconnection reserve sharing) – maximum demand + demand side participation.
Reserve plant margin	See *generation reserve margin*
Rules	See *National Electricity Rules*
Scheduled demand	That part of the electricity *demand* supplied by scheduled generating units (see also electricity *demand*). It excludes that part of the demand supplied by *non-scheduled generating units*. Scheduled demand is measured on a *generator-terminal* basis. For a *region*, the measure includes scheduled generators within the region plus imports into the region minus exports from the region.
Scheduled energy	The electrical energy requirement supplied by scheduled generating units. It excludes that part of the electrical energy requirement supplied by non-scheduled generating units. Scheduled energy is measured on a generator *sent-out basis*. For a *region*, the measure includes scheduled generators within the regions plus imports into the region minus exports from the region.
Scheduled Generator	Scheduled by NEMMCO as part of central dispatch.
Sent-out basis	A measure of *demand* or *energy* (in MW and MWh, respectively) at the connection point between the generators and the *network*. This measure includes: Consumer *load*; and Transmission and distribution losses.
Sent-out generation	In relation to a generating unit, the amount of electricity supplied to the transmission or distribution network at its connection point.
Smart meter	A communications-enabled 'time-of-use' meter, which can indicate the overall level of electricity consumption at any given time. Smart meters can thus allow customers to adjust consumption in response to information about consumption..
Spot market	Wholesale trading in electricity is conducted as a spot market. The spot market allows instantaneous matching of supply against demand. The spot market trades from an electricity pool, and is effectively a set of rules and procedures (not a physical location) managed by *NEMMCO* (in conjunction with market participants and regulatory agencies) that are set out in the *Rules*.
Spot price	The price for electricity in a trading interval (a half hourly period) at a *regional reference node* or a connection point.
Supply	The delivery of electricity.

Supply-demand outlook	Calculation of all available electricity supply minus expected demand within the bounds of the capabilities of the networks to determine whether supply will be adequate to meet demand over the next 10 years.
TransGrid	The corporation that owns, operates and maintains New South Wales' high voltage electricity transmission network. TransGrid is owned by the NSW Government.
Transmission network service provider (TSNP)	An entity that plans, owns, operates and/or controls the high-voltage *transmission* assets.
Transmission networks	The high-voltage *transmission* assets that transport electricity between generators and *distribution networks*. Transmission networks do not include connection assets to generators or loads.
Unserved energy (USE)	The shortfall that occurs when there the amount of electricity generated is insufficient to meet *demand*. Under the provisions of the Reliability Standard, each region's annual unserved energy is planned not to exceed 0.002% of its total energy consumption for the year.
Value of Lost Load (VoLL)	A value set by the *Reliability Panel*, and assessed as the value of lost electrical consumption. The current VoLL is $10,000 per MWh. This is the maximum *spot price* in the electricity spot market.
Watt (w)	Basic measure of electrical power.
Watt-hour (Wh)	Basic measure of electrical energy (energy = power x time).