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14 November 2008

Dr John Tamblyn
Chairman
Australian Energy Market Commission
AEMC Submissions
PO Box A2449
Sydney South NSW 1235

Dear Dr Tamblyn,

AEMC Scoping Paper – Reference EMO 0001

Please find attached Babcock & Brown Power's (BBP) submission to the Australian Energy Market Commission's (AEMC) *Review of Energy Markets in light of Climate Change Policies: Scoping Paper* (October 2008).

BBP supports the introduction of CPRS but highlights that it represents a fundamental structural reform without parallel in terms of the breadth and depth of change. Additionally, by itself the expansion of the CRET from 9,000GWh to 45,000GWh represents a substantial change to Australian electricity markets.

Accordingly, the impacts of CPRS and the CRET on the regulatory framework that supports Australia's energy markets must now be identified, analysed, debated, and subject to appropriate risk management. And to this end, BBP supports the Ministerial Council of Energy's (MCE) referral, and welcomes the AEMC's Review.

If you have any questions with regard to BBP's submission or require any further information please contact me on 07 3011 7632 or James Reynolds on 07 3011 7646.

Yours sincerely,

AKremor.

Andrew Kremor
Executive General Manager
Babcock & Brown Power Pty Ltd

AMEC Review –
Energy Market Design in response to CPRS and CRET

14 November 2008

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AEMC Scoping Paper October 2008 Reference EMO 0001
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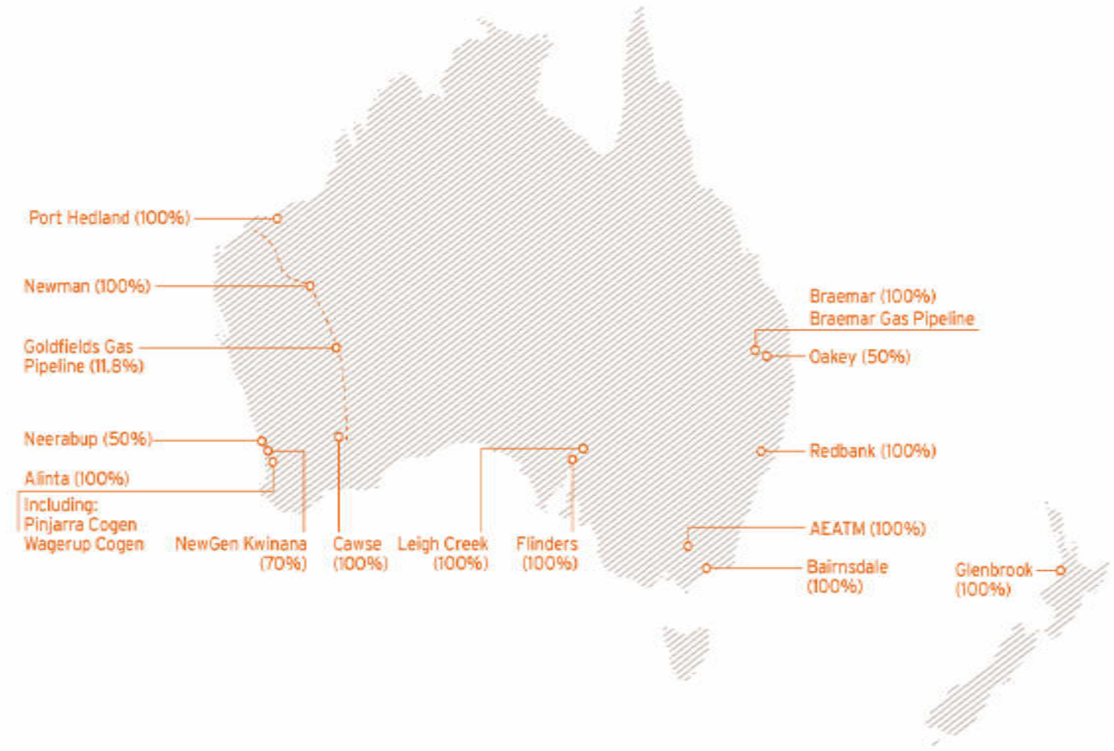
Overview to Babcock & Brown Power

Babcock & Brown Power Limited (BBP) is an Australian listed power generation business with an extensive portfolio of assets diversified by geographic location, fuel source, customers, contract types and operating mode. The portfolio has interests in twelve operating power stations representing over 2,900MW[1] of installed generation capacity and two power stations under construction. BBP's parent, Babcock & Brown has been developing, operating and acquiring the generation portfolio over a period of 10 years.

The location of the current energy assets in the company group is as follows.



BBP employs around 900 of people across its portfolio of assets, and has corporate service centres in Sydney, Brisbane, Adelaide and Perth.

[1] Some Assets have minority shareholders

BBP supports the introduction of Carbon Pollution Reduction Scheme (CPRS) but it represents a fundamental structural reform to Australia's political economy, and is without parallel in terms of the breadth and depth of change. In addition, the proposed expansion of the Renewable Energy Target Scheme (CRET) from 9,000GWh to 45,000GWh by itself represents a substantial change to Australian electricity markets.

The impacts of CPRS and the CRET on the regulatory framework that supports Australia's energy markets must now be identified, analysed, debated, and appropriately risk managed. And to this end, BBP supports the Ministerial Council of Energy's (MCE) referral, and welcomes the Australian Energy Market Commission's (AEMC) *Review of Energy Market Frameworks in light of Climate Change Policies* ("the Review").

BBP considers that the current un-synchronised timetables between the Commonwealth's CPRS and CRET change, and the AEMC's review of energy market design as a result of CPRS and CRET, could result in future regulatory failure or prolong the term of the transition as a result of missing opportunities to utilise cross-sectoral (and log-rolling) policy responses (specific reference to the Electricity Sector Adjustment Scheme) to address implementation challenges. BBP encourages that there be further consideration by policy makers around ensuring that the preliminary findings from AEMC's review as it occurs be considered in forming the detail around implementing the CPRS and CRET.

Specifically, BBP believes the Electricity Sector Adjustment Scheme (ESAS) which forms part of the CPRS policy should be informed by the findings of the AEMC Review. As stated in the Green Paper, the ESAS is intended to deliver comprehensive support to the coal fired generation sector, and workers, communities and regions dependent on it by:

- Underpinning investor confidence in the electricity generation sector
- Facilitating structural adjustment for individual firms, workers, communities and regions
- Ensuring security of energy supply - including through measures which facilitate adaption to low emissions production.[2]

Given the comprehensive nature of the AEMC Review of the impact of CPRS and MRET on the electricity market, and the current uncertainties that exist around the extent of the impact on the electricity and financial markets, BBP believes aligning the ESAS with the Review maximises the opportunity for an orderly transition across the electricity sector.

BBP's submission to the Review is structured as follows:

- Section 1 sets out the key themes emerging in Australia's energy markets, particularly, the practical and regulatory challenges that our sector was facing prior to the introduction of CPRS and the expanded Commonwealth RETS
- Section 2 provides specific comment on the Review's Issues and Questions. We have not exhaustively addressed each issue and question in this submission.

[2] Carbon Pollution Reduction Scheme Green Paper July 2008, page 371.

Section 1 Background

In this section, BBP provides an outline of the current state of Australian energy markets, with a specific focus on electricity markets. This section identifies the key challenges that the energy markets were facing in a business as usual environment, i.e. without CPRS, and the expanded CRET. Importantly, by highlighting these challenges it provides context to the practical limitations facing the regulatory changes needed to facilitate CPRS and CRET.

The current state of Australian energy markets can be summarised as follows.

A substantial investment task over the next 10 years

In a business as usual environment the power industry faces an investment task of around $33 billion to 2020[3] to meet growing energy consumption. This represents a c.60% increase on top of the current depreciated carrying value of power station stock of c.$54 billion, as outlined below in Table 1.

Table 1 – Key characteristics of Australia's Power Generation Stock 2008

Generation Technology	Installed Capacity* (MW)	Replacement Cost# ($/kW)	Replacement Value ($m)	Average Fleet Age* (Yrs)	Total Useful Life# (Yrs)	Remaining Useful Life (Yrs)	Depreciated Value ($m)
Hydro	7,609	2,500	19,023	37.2	100	62.8	11,953
Black Coal	22,601	2,250	50,852	23.5	50	26.5	26,957
Brown Coal	7,335	2,750	20,171	28.1	50	21.9	8,842
Natural Gas	6,688	1,100	7,357	15.2	30	14.8	3,629
CCGT	2,154	1,550	3,339	5.0	30	25.0	2,782
TOTAL	46,387	2,172	100,742	24.4	54	30.0	54,164

*Source (esaa, 2008). #B&B Est.

Unlike historic periods in the Australian power industry there is almost no spare capacity that increasing consumer demand can utilise while new power stations are planned, designed and built, a fact highlighted by NEMMCo's Statement of Opportunities (SOO) 2008 forecasting possible breaches in targeted spare capacity in:

- Victoria and South Australia summer of 2008/09
- Tasmania summer 2010/11
- South Australia summer 2010/11
- Queensland summer 2013/14
- New South Wales summer 2014/15.

Similarly, the 2008 SOO prepared by the Independent Market Operator (IMO) in Western Australia indicated a shortfall in targeted spare capacity beyond that already in service or under construction would arise in that market in 20010/11.[4]

The Commonwealth Treasury's CPRS Modelling also shows that from 2009/10 the investment need in Australian electricity markets is around 700MW per annum to meet customer load growth.[5]

3 ESAA, June 2008, The Impact of an ETS on the energy supply industry, page 9, and NEMMCo SOO 2007, IMOWA 2007.

4 IMO, July 2008, Statement of Opportunities, page 4.

The reserve plant margin for the NEM in 2008 was approximately 10% over PoE50 demand against typical world benchmarks of 15% and US standards of 15-20%. Historically, it is important to note that each time the east coast grid has undergone some form of restructure or deregulation reform process, the market was characterised by reserve margins of between 20-40% in aggregate.

In the face of this substantial investment task, the next generation of power station generation will be drawn from less C02 intensive power plants with operating characteristics dissimilar to the current power station fleet.

An inherently stable technology profile in aggregate power station stock

In the absence of CPRS, an important feature of Australian aggregate power generation stock is the relative 'inertia' of the technology profile. That is, the technology profile of the power generation stock has been in a stable state.

The current technology profile is dominated by brown and black coal fired generation, with gas turbines, hydro and wind making up the balance. The inertia in the generation stock reflects that typically it takes between 4 to 7 years to plan, design, develop, build and commission power stations. Accordingly, widespread changes in the make up of the aggregate generation profile are likely to be relatively slow moving in nature.

The CPRS and CRET represent a fundamental challenge because by definition it is designed to 'disrupt' the inert technology profile in Australia's generation stock. This disruption is necessary in making the transition from C02 intensive generation to a less C02 intensive generation – the principle concerns for the AEMC is the duration and the extent of disruption.

Unfortunately, given the historical experience of the time taken to invest in new power station stock it is likely that the aggregate generation portfolio may take fifteen years or more to achieve a desirable level of stability.

Financial crisis – tightening of debt markets

Currently, the private sector holds around 18,500MW out of the total Australian generation capacity of 47,000MW, which represents around 40% of installed generation capacity and 36% of the value of generation stock as noted in Table 2. Private investment in power generation plants is vitally important from a capital allocation perspective, but that participation relies on equity and debt providers and markets.

[5] MMA, October 2008, Report to Federal Treasury – Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets, page 24.

Table 2 – Privately Owned Australian Generation Power Stock by Fuel/Operational Type -2008

PRIVATE SECTOR	Installed Capacity* (MW)	Replacement Cost# ($/kW)	Replacement Value ($m)	Average Fleet Age* (Yrs)	Total Useful Life# (Yrs)	Remaining Useful Life (Yrs)	Depreciated Value ($m)
Hydro	526	2,500	1,315	43.7	100	56.3	740
Black Coal	3,440	2,250	7,740	17.7	50	32.3	5,006
Brown Coal	7,335	2,750	20,171	28.1	50	21.9	8,842
Natural Gas	5,256	1,100	5,782	15.8	30	14.2	2,744
CCGT	1,859	1,550	2,881	5.0	30	25.0	2,401
TOTAL	18,416	2,057	37,890	21	44	23.0	19,733

*Source (esaa, 2008). #B&B Est.

Unlike the central borrowing agencies of the State Governments private debt holders have substantial options and alternatives on where they invest, and clearly look to achieve their returns through optimising duration and pricing decisions on assets invested in. Australia's generation stock is no different. The level of debt[6] used to finance these privately owned investments ranges from 50 to 80% of the total investment. The private sector coal fired fleet is financed by $9 billion in senior project finance debt, and $2.5 billion in corporate-style facilities (with an aggregate gearing of c.60%). Of this, c.$6.5 billion must be refinanced between 2009 and 2012.

The existing financial crisis makes refinancing challenging at best. Given that almost 60% of private sector power station debt requires refinancing over the next three years on a business as usual basis (without CPRS and CRET), the introduction of CPRS and CRET will clearly increase the risks of failures.

Most importantly, failures to refinance by high emitting power stations may lead owners to walk away from assets on commercial grounds. A decision by Administrators to retire an asset (i.e. exit) before new power station entry has occurred on the grounds of insolvency seems to be more than a theoretical possibility, given ongoing production gives rise to a CO2 liability which may not be recoverable. This has implications for the security and reliability of the power system.

What does this mean to energy market design and framework?

The CPRS and CRET are disruptive policy interventions designed to shift the status quo. However, and unfortunately for policy makers, given the essential nature of electricity, the transition period requires that the system remains safe, and that supply is both reliable and affordable.

From BBP's perspective the introduction of CPRS and CRET, particularly how the energy sector is transitioned, represents a substantial challenge, and if ineffectively managed may materially affect the reliability and performance of Australian energy markets in an enduring way. To enhance the probability that system capacity and reliability is maintained during the transition there is a need for greater information flows between the AEMC's review and the Commonwealth's legislative program implementing CPRS and CRET.

6 Power stations are long lived and capital intensive. These aspects make debt financing an important element in investments in power stations as the contracting parties are able to set long term contracts with certainty around the fixed portion of debt needed for the investment, the level of repayments and the risk adjusted price for the total finance provided.

The Commonwealth's legislative program for CPRS and CRET, particularly the arrangements surrounding sector adjustment assistance, are more likely to be enhanced if they consider the AEMC's preliminary findings. In particular, such a linkage will allow policy makers to consider alternative policy responses where the AEMC identifies gaps or limitations in the existing energy market framework.

As these processes operate in parallel over the first six months of 2009 there is an opportunity for policy makers to adjust the scope of the AEMC's review to introduce this critical information exchange.

Section 2 Response to Issues and Questions

Generally, BBP supports the AEMC's Scoping Paper Review of the Issues, and considers that the proposed questions are sufficiently detailed to explore the likely impacts of CPRS and the expanded CRET on the energy regulatory framework. In this section, BBP provides suggestions on several issues and questions raised in the AEMC Scoping Paper. The positions represent a preliminary view, and during the course of the AEMC's review BBP will be providing further submissions on the issues, and questions raised within the scoping paper.

BBP's response to the AEMC's Issues and questions is set out as per the following structure:

- AEMC Issue and key questions
- Identification of issues that BBP considers the AEMC should be cognisant of in its review.

Issue 1: Convergence of gas and electricity markets

Climate change will mean a larger role for gas, but differences between gas and electricity markets may mean that the market response is inefficient.

AEMC's questions

1. ***How capable are the existing gas markets of handling the consequences of a large increase in the number of gas fired power stations and their changing fuel requirements?***
2. ***What areas of difference between gas and electricity markets might be cause for concern and how material might the impacts of such differences be?***

It is expected that the current gas market will be challenged by the expected increase in volume and volatility in gas consumption from increased penetration of gas fired power stations. BBP considers the leading constraints on the existing capability of the gas markets include:

- *Australian gas markets are immature, illiquid and lack price transparency* – reform of the Australian gas markets are required so that trading and risk management of gas can keep pace with trading and risk management of electricity, which is a necessary building block for future trading and risk management of carbon related products
- *Existing supply contracts* – invariably these are long contracts, and settled making a move to a short term market challenging. To support the increased penetration of gas fired power stations will require greater contract and trading risk management capabilities in gas markets
- *Back to back supply contracts for source and transportation* – the existing gas market demonstrates contractual congestion at the source and on gas transportation assets, potentially limiting competition and efficient market outcomes
- *National planning for gas infrastructure* – gas pipelines are needed to support the development of more gas fired generation, and to some extent there will be a need to ensure more coordination in gas pipeline investment, however, existing

gas pipelines are privately owned, accordingly any regulatory change designed to achieve better coordination across networks will need to address substantive property rights concerns
- *Gas technical specification* – contracts and transportation infrastructure has been built on asset specific technical specification – as new gas with disparate technical specification is commercially found this will create a challenge to the gas market in terms of; addressing the inherent property rights contained in current arrangements; and being able to flexibly meet the requirements for new gas.

In relation to the WA gas market, BBP is concerned that the existing structural characteristics of upstream gas markets is potentially acting as a barrier, limiting effective competition. BBP's concern is that this may represent a clear barrier to an efficient transition to lower CO_2 intensity gas fired power stations in the generation mix.

Security of supply concerns are also relevant in WA as currently the Perth region is effectively entirely dependant on the one transmission pipeline for delivery of gas. As shown by the recent Varanus Island incident, the WA market is vulnerable to single incident caused disruptions in its gas supply. An increase in the proportion of gas generation in the overall WA generation portfolio will need to be carefully considered in the light of security of supply considerations.

More importantly, the CoAG led legislative reform of gas markets won't be completed until 2010, at the same time as CPRS will be introduced. Accordingly, there is no certainty around what the likely impacts might be, and there is a substantial body of work and analysis that industry needs to undertake to determine the likely impacts.

BBP expects that the creation of the Australian Energy Market Operator (AEMO) and the establishment of a short term gas market in 2010 for the east coast's major capital cities are positive steps that will enhance the capability of existing gas markets to handle the consequences of more gas-fired power stations. To this end, the AEMC's role of achieving CoAG's goal of consistency between legislative and regulatory instruments between electricity and gas markets has incredible importance with the introduction of CPRS and CRET.

Issue 2: Generation capacity in the short term

Delays to generation investment due to current uncertainty on the future policy settings, and timescales required to commission new investment, could result in a transitional problem in respect of the adequacy of generation capacity

AEMC's questions

3. ***What are the practical constraints limiting investment responses by the market?***
4. ***How material are these constraints, and are they transitional or enduring?***
5. ***How material is the likelihood of a need for large scale intervention by system operators? How likely is it that this will be ineffective or inefficient?***

As noted by esaa (2008), the Australian energy markets require around $33 billion in investment to 2020 or on generation installed measures around 700MW per annum.[7] The investment task is substantial.

Ordinarily, the principle that new investment in power stations will occur so long as wholesale energy prices are greater than the long run marginal cost of plant would ensure that new power stations enter in time to supply energy as uneconomic plant exits. The assumption of smooth transition between old and new power stations will be tested because:

- the current crisis in debt and equity markets is likely to create additional uncertainty for existing power stations refinancing . For new power stations there is likely to be less capital available, and compared to historic periods the cost of debt and equity to new power stations is likely to be materially higher. Anecdotal evidence seems to suggest that margins on term debt facilities have now shifted to c.250-300bps over BBSY compared to the historical range of 110-150bps. While the increase in margins has been clearly affected by the current credit crisis, even if we look through the current credit market industry consensus seems to suggest that spreads will revert to a new and higher range of 180-250bps over BBSY, in some respects reflecting the early-1990s market conditions.[8]
- CPRS and CRET increases the uncertainty around the expected earnings and longevity of existing power stations – this has a knock-on effect on determining the likely economic and financial pay-offs for new power stations
- the expanded CRET will result in more wind generation, particularly, in South Australia, Victoria and Western Australia – as an intermittent load the regulatory arrangements to facilitate necessary load following generation is subject to considerable debate creating further uncertainty for new investment.

A potential outcome from the current financial crisis is that it will make refinancing of existing debt challenging for several reason. The first response by international debt markets over the last 12 months has been to stop offering 10 to 15 year money. Debt terms are now reducing to between 3 and 5 years, with 7 years considered an

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7 ESAA, June 2008, The Impact of an ETS on the energy supply industry, page 9, and NEMMCo Statement of Opportunities 2007, IMOWA 2007.

8 Australia's CPRS and CRET response is likely to have some bearing on our markets overall systematic risks when compared to other countries that have not implemented CPRS. In addition, with the CAPM set up over the period of transition there is likely to be a higher risk attributed to Australian energy assets.

outside maximum.[9] This is a practical break from historical practice in Australia's project debt market.

In addition, the current financial crisis has the potential to impact on the short and medium term strategies of international banks participating in the Australian market. As reported in business media, banks with international operations are increasingly focused on ensuring stability in home country operations. For Australia, any loss or reduced operations by international banks is likely to make any financing activity challenging.

Clearly, with CPRS and the CRET overlayed there is a real practical challenge for refinancing of existing brown and black coal power stations. The introduction of CPRS and CRET on existing power stations, and the ongoing viability of these businesses will potentially have an impact on investment in new generation (this is discussed in detail under Issue 8).

For the AEMC, the present financial crisis could potentially result in early exit by existing power stations, and delayed entry by new power stations – potentially exacerbating the tight supply/demand balance in Australian energy markets.

Importantly, are these practical investment constraints material and enduring?

BBP considers the investment constraints to be material on account of the:

- the debt refinancing requirement in the near term and the present state of equity and debt markets
- noted deficit in spare capacity in Australian energy markets
- need for ongoing investment in generation capacity to supply growing demand.

Whether the investment constraints endure will be driven by:

- the permanency of the noted changes to debt term duration and pricing in international debt markets
- financial markets[10] general perception of uncertainty of earnings for the Australian energy market, which is driven by uncertainty with regard to high C02 emitting power plants and the investment need to support new low C02 emitting power plants.

Given the noted reserve deficits in the NEM, and less so in the Wholesale Electricity Market (WEM) in Western Australia in the short term, and the estimated required investment in new capacity to meet growth in energy consumption there is the increasing likelihood that NEMMCo and the IMOWA may need to intervene in the market. Generally, NEMMCo's options to intervene in the market include:

- contracting for reserve capacity in the regions with capacity reserve deficits
- contracting for ancillary services to provide greater system support and stability
- in instances where generators do not bid due to uneconomic wholesale price directing a power station to generate
- monitoring accumulated price outcomes to apply the administered price

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[9] Babcock & Brown 2008

[10] If debt markets maintain 5-7 year terms at higher costs of debt, then equity holders must carry the additional risks from more debt refinancing over the life of the power station. Equity holders are likely to demand a higher premium to reflect this risk – or alternatively look to take a greater stake in the investment.

- invoking of ‘emergency’ powers to resolve significant market emergencies.

In the WEM in Western Australia, the IMO has published a SOO-WA[11] that indicates sufficient generation capacity exists through 2009/10, but that a further 226MW will be required for 2010/11. The SOO-WA also noted that the most recent Expression of Interest process, conducted during the first quarter of 2008, identified 1,036 MW of potential new capacity in 2010/11 - however, how much of this potential capacity proceeds is unclear.

More importantly, short term capacity shortages may still arise, for example in relation to unforeseen high forced outage levels or late commissioning of new generators. In such circumstances, the IMO has the ability to call for Supplementary Reserve Capacity (SRC) to address short term deficits. This has similar effects to the reserve trader provisions in the NEM.

It is difficult to categorically determine the likely need for market intervention (although BBPs view is that it is inevitable in the absence of a suitable structural adjustment package for the segments of the industry facing a ‘transition to decline’). However, given the uncertainty BBP considers that the AEMC should examine the existing market interventions under a range of alternative operating scenarios to identify any gaps or weaknesses.

BBP considers that this analysis is critical as it will provide the AEMC with the basis on whether the existing arrangements need to be amended or whether the materiality and duration of the risks are such that there may need to be a more fundamental change to market design.

Issue 3: Investing to meet reliability standards with increased use of renewables

If standards relating to the reliability of electricity supplies are going to continue to be met, then investment in intermittent generation (such as wind-farms) will need to be matched by investment in other forms of generation (or transmission) – to ensure that supplies are reliable when wind generation is unavailable. Existing market frameworks might not deliver investment in such “back up” capacity at an acceptable cost.

AEMC’s questions

6. ***How material is the risk of a reduction in reliability if there is a major increase in the level and proportion of intermittent generation?***
7. ***What responses are likely to be most efficient in maintaining reliability?***

BBP considers that there is a material risk of Australian energy markets being unable to meet reliability standards as a result of a greater proportion of installed generation capacity being intermittent – wind, wave, solar. Wind generation represents a proven generation option which has experienced widespread increases in penetration across international electricity markets.

The policy question when examining the impact of intermittent generation on existing electricity markets can be broadly categorised as:

- system balancing – managing short run fluctuations

[11] http://www.imowa.com.au/Attachments/RC_Attachments/2008_SOO_Final_v0.1.pdf

- system reliability – maintaining generation margin over peak demand.[12]

The implications on electricity markets from increased penetration of installed intermittent generation, particularly wind, is that the overall economics of the aggregate power generation portfolio improves from reduced C02 emissions but existing and new thermal generation plants are required to operate with greater flexibility, and a greater need for network reinforcement and system balancing services exists.[13]

In terms of system balancing and stability some key requirements include:

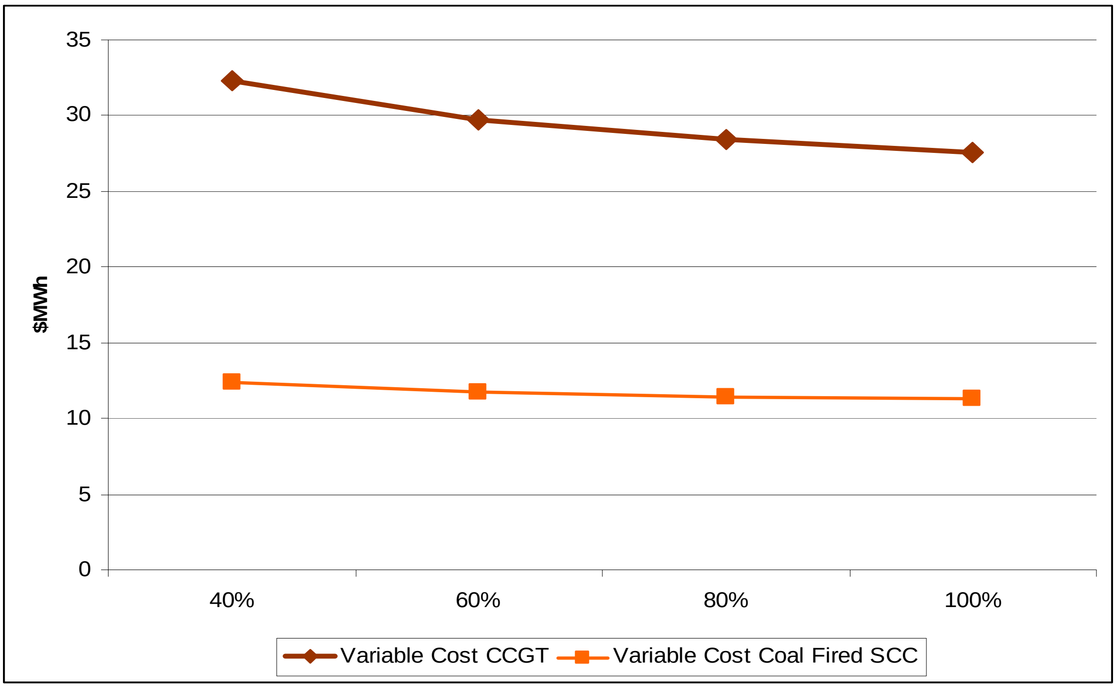
- the underlying technical performance of intermittent plant and the need for standardisation
- increasing spare capacity on transmission and distribution networks to ensure that overloading is minimised particularly when transferring loads
- greater investments in reactive compensation investments to support network stability and balancing
- greater capability in power system and network operations – protection equipment and systems, and smarter switching capability
- increased ancillary services to reduce volatility in power quality.

For system reliability there is a general need for load following generation. A recent report in Western Australia indicated that for the SWIS, for every 200MW of installed wind generation there is a requirement for around 50MW of load following generation capacity. In the Australian energy market context, if around 9,500MW of renewable generation is assumed, with wind generation being around 7,000MW (wind generation broadly consistent with Garnuat and Commonwealth Treasury Modelling for CPRS) then there will clearly be a sizeable need for load following generating capacity.[14]

Importantly, BBP considers that in the case of load following generation this is not likely to be CCGT or even OCGT due to the sharp downward sloping nature of gas turbines plant heat rate curves. For gas turbines, harder running moves the SRMC of the plant down the cost curve, whereas, the heat rate curves for a coal fired plant are much flatter, making them more suited to load following generation. Figure 1 illustrates.

[12] UK Energy Research Centre (2006), The Impacts & Costs of Intermittency.
[13] UK Energy Research Centre (2006), The Impacts & Costs of Intermittency.
[14] Market Advisory Group (IMOWA), Renewable Energy Generation Group, Agenda #3.

Figure 1 – Variable Costs per $/MWh for CCGT and Coal Fired Plant



Studies of intermittent generation impacts on network systems highly recommend careful consideration of local characteristics of the country, and networks.[15] The scope of the challenge in efficiently moving system operations towards effectively accommodating substantive penetration of wind (intermittent generation) generation requires:

- a detailed understanding of the quality of the resource
- knowing the correlations or lack of between intermittent generation and the overall generation profile
- a robust network including substantive spare capacity, greater investments in reactive capacity, and enhanced smarts around protection and sophisticated switching capabilities
- enhanced capabilities at accurately forecasting intermittent generation
- having a regulatory and system rules which balance the impact of intermittent generation on system stability and reliability.

BBP considers the existing regulatory and system rules would require substantial modification to accommodate intermittent generation. For instance, Australian electricity networks, particularly transmission, can be generally characterised as geographically long networks without the degree of meshing associated with the European networks – where wind generation penetration has been substantial.

The investment required to ensure that Australia's transmission and distribution networks are able to accommodate intermittent generation represents a substantial task, and not readily achievable through existing regulatory arrangements, such as the regulatory test, and transmission revenue regulation by the AER, and the Economic Regulatory Authority (ERA) in Western Australia. Importantly, there are a range of policy issues in deciding the nature of how the cost of recovering this

15 UK Energy Research Centre (2006), The Impacts & Costs of Intermittency.

necessary network investment occurs without distorting efficiency signals in the market.

More importantly, any consideration of changing the regulatory and market rules to accommodate the increase in intermittent generation should examine the following issues:

- cost recovery mechanisms for transmission and network investments and to accommodate demand side management
- the standardisation of technical standards for intermittent generation
- the standardisation of operational standards for load following generation
- the extent that the existing energy only market would be able to compensate load following generation.

Issue 6: Augmenting networks and managing congestion

Climate change policies may result in higher levels of congestion on energy networks and there is a risk that congestion costs are not minimised, or that they create a significant risk for potential investors.

AEMC's questions

15. ***How material are the potential increases in the costs of managing congestion, and why?***
16. ***How material are the risks associated with continuing with an "open access" regime in the NEM?***
17. ***How material are the risks of "contractual congestion" in gas networks and how might they be managed?***
18. ***How material is the risk of inefficient investment in the shared network, and why?***
19. ***How material is the risk of changing loss factors year-on-year?***

BBP considers that augmenting and managing congestion in the NEM and WEM are challenges within the existing market design, and CPRS and CRET are expected to exacerbate these challenges.

The policy objective of the CPRS and CRET is to significantly reduce the C02 intensity of Australia's aggregate generation profile, which can only be achieved by facilitating investment in less C02 and zero C02 generation stock. Market expectations suggest substantial penetration of wind generation, and other renewable generation with similar intermittent operating profiles. These are expected to require new investment in energy infrastructure that is located from existing loads and networks. In addition, to location driven investment there is also expected to be the need for substantial investment in existing networks to accommodate the operating characteristics of the new generation, while managing the gradual loss of existing generation.

In short the challenge for Australian energy networks is to connect, reinforce existing networks, and manage congestion, but faced with disparate operating characteristics of power generators.

In the current regulatory environment, augmentation of networks and congestion management is undertaken by the network service providers and NEMMCo (except in WA, where these responsibilities reside only with the network service provider).

The AER plays an important role of energy market enforcement, and in approving the terms of access and the allowed returns for network providers. The introduction of the National Transmission Planner (NTP) from June 2009 will also provide greater guidance and direction on transmission investment.

The practical experience of BBP in the WEM would highlight that congestion is primarily managed by the network service provider, WP, through planning and investing in its network infrastructure on a long term basis. System Management, a ring fenced unit within WP, manages constraints and congestion in the shorter term, primarily through movements of the balancing generator (Verve Energy) and issuing dispatch instructions to IPP generators to deviate from their resource plans.

BBP considers a greater role for competition in the provision of both energy balancing and ancillary services is vital to improving the efficiency of the WEM. This would be an important step towards further improving efficiency in providing these services.

BBP considers there to be a range of issues within the existing regulatory arrangements for transmission augmentation and congestion management that the AEMC should consider as part of its review. More importantly, BBP considers that the existing regulatory regime for transmission networks may require substantial change as a result of CPRS and CRET. In particular, the key areas for examination include:

- regulatory test – the provision of more information in advance of network investment forecasts is required to provide the market with greater time to decide
- approval approach to new investment – network constraints and congestion impact on all generators, and greater connectivity and enhanced transmission and regional interconnection are important features, and the current regulator approved approach may need to be augmented by looking further a field to other regulated network infrastructure for an alternative that can address the likely impacts from CPRS and CRET[16]
- examine cost recovery mechanisms, particularly with regard to the expected requirement for greater investment in deep connection assets as a result of increased penetration of intermittent generation
- examine the capacity of being able to gain greater productive and dynamic efficiencies in the delivery of the expected investment in transmission networks by:
    - standardising the technical and operating characteristics for transmission networks in response to CPRS and CRET generation
    - examining the potential for joint service delivery models for transmission businesses to achieve greater economies of scale in network investment and transmission operations.

[16] ACCC's approach to regulating airports around new facilities investment, Dalrymple Bay Coal Terminal's approach to facility expansion with involvement of users and the regulator may provide examples that the AEMC can examine as a starting point.

Issue 7: Retailing

Changes in the level or volatility of costs faces by retailers, combined with ongoing price regulation, may reduce the effectiveness of retail competition.

AEMC's questions

20. ***How material is the risk of an efficient retailer not being able to recover its costs, and why?***
21. ***What factors will influence the availability and pricing of contracts in the short and medium term?***
22. ***How material are the risks of unnecessarily disruptive market exit, and why?***

In Australian energy markets, Victoria is the only the market where energy retail tariffs are not to be set by State governments in the future. Without cost-reflective tariffs any reforms are set for failure.

To this end, there is a substantial risk that an efficient retailer will not be able to recover its costs. More importantly, without complete pass through of the full cost of energy consumption there is likely to be the opportunity for greater market distortions.

BBP considers that there are a range of factors affecting the availability and pricing of contracts in the short and medium term. These are described below.

The greatest impact on the availability and pricing of contracts is uncertainty. For example, a current high C02 intensive generator is less likely to be willing to offer any form of short or medium term contract on its output until there is some certainty around its total costs within CPRS. Importantly, the greater the ambiguity as to the likely impact on existing generators cost base it is probable that generators will continue to offer limited future financial contracts.

And even once CPRS and CRET commences there is a substantial degree of uncertainty for generators in setting forward contract prices that reflect their total costs of production. Importantly, the AEMC and other regulators, particularly the AER and the ACCC, will need to ensure that its market monitoring roles investigate where energy market prices are being set below short and long run marginal costs.

The challenge of availability and pricing of contracts is likely to be enduring as recent Commonwealth Treasury modelling explicitly applies a trajectory that requires a successful multi-staged approach to international agreement as the basis for ratcheting Australia's trajectory, and costs of addressing carbon reduction. If legislated, these carbon market parameters increase the uncertainty and risk in the market around price – making it difficult for existing generators to set a price that they expect to fully recover their total costs of production.

BBP considers that other key factors to consider during this transition period include:

- the settling point for capital costs, including infrastructure, for new generation
- the actual costs of abatement, either direct or indirectly through the purchasing of permits
- the emergence of international agreements on C02 emissions occurs as expected

- the extent to which generators and retailers can reach a common understanding that allows for the formation of contracts.

As outlined above there is a substantial risk of early exit of existing generation plant. The AEMC needs to consider that existing generators must consider its equity and debt holders, and with CPRS and CRET the medium to long term stream of costs and revenues may signal that the generator is better to exit sooner rather than later.

Where existing generation is needed to provide load following support for wind and intermittent generation or to support transmission and inter-regional connection then the current regulatory and commercial arrangements would need to reflect the important role played by this type of plant. For the AEMC, the critical challenge for the market, particularly during the transition phase, is to determine whether the financial contract market would be able to adequately accommodate the role of load following generation or simply stand by capacity from existing power plants. Alternatively, the AEMC may consider that in the short term there may be a role for capacity payments for load following and system support generation.

There is substantial body of domestics and international work considering the issue of capacity payments and energy only markets. The AEMC's consideration of broader market design examining capacity payments must decide the need for capacity payments, and determine whether the mechanism is temporary or permanent.

Issue 8: Financing new energy investment

Climate change policies will require large investment in renewable and non-renewable generation capacity – and in energy networks. Current market settings may result in risks which increase the costs (or reduce the availability) of debt and equity finance..

AEMC's questions

23. ***What factors will affect the level of private investment required in response to climate change policies?***
24. ***What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?***

The CPRS is designed to adversely impact existing generation that heavily emits C02. As outlined in Issue 2, the existing generation portfolio, particularly the privately owned stock, has a level of debt that reflects a 'sizing' based on expected free cash flows without a CPRS. Once CPRS impacts are factored it is likely that existing generators will require a commitment of more equity to restore balance sheets. Where wholesale energy prices, and the cost of C02 results in existing generators financial position deteriorating then there is the possibility that debt holders may not fully recover their investments.

Such an outcome would simply increase the uncertainty associated with Australian energy markets. This would increase risks for the whole industry, and would increase the cost of debt and equity for all power generators.

More importantly, such an investment climate could be enduring in the Australian energy market as displacement of current generators from the aggregate generation portfolio as a result of CPRS can be reasonably predicted, and consequently will be followed. The following discussion illustrates.

For simplicity, if it is assumed that the ultimate goal of CPRS is to move the aggregate generation portfolio's carbon intensity to below 0.2t, then the transitional neutral position would rank the current aggregate generation portfolio at 1. For high C02 emitting plant their individual coefficients would be between 1.25 to 1.5 and 0.8 to 1.0 for brown and black coal respectively, OCGT around 0.6, and CCGT around 0.4.

As the energy market adjusts to CPRS then high C02 emitting plant without any assistance or changes to existing market frameworks is likely to exit first – for South Australian and Victorian regions this raises the risk of 'exit before entry'. These regions already face short term reliability issues, along with the longer term reality that increased wind generation will require substantial investment in supporting energy infrastructure.

The black coal plants of New South Wales, Queensland and Western Australia would follow, and eventually in time, the gas fired generation stock would also be gradually displaced. The likelihood of all existing generation being displaced before current expected asset lives is largely unknown, and depends greatly around:

- The adequacy of Electricity Sector Adjustment Scheme (ESAS), and that this at least provides existing financiers, particularly, debt holders with the opportunity to maintain the financial capital of their original investments. The scope of the ESAS is yet to be finalised, however, market estimates range from $10 billion up to $15 billion[17]. More importantly, the ESAS mechanism represents an important feature to maintain and restore certainty within the investment climate.

  A possible option for policy makers would be aligning ESAS with a form of contracting for availability or through capacity payments to existing generators which may provide smoother transition that deals with the challenge of existing financing arrangements, short term reliability challenges, and longer term investment incentives.[18] (Of itself, this highlights the importance of the AEMC being formally involved in any design of an ESAS).

  Alternatively, for policy makers the level of uncertainty around the likely impact on existing generators in terms of timing, financial value loss, and impacts on market operations during the transition is symmetric. However, the consequences from possible outcomes are likely to be asymmetric in terms of overall impact.

  For instance, if the ESAS is inadequate in addition to the individual power station impacts (loss of value, insolvency and early exit) there is the potential societal loss during the transition from there being insufficient capacity to meet energy load, and the costs of reduced system security and reliability.

  The impact of this dynamic on investment certainty makes the setting of an adequate ex-ante ESAS in the absence of AEMC input problematic. More importantly, this dynamic suggests the importance of ensuring that the policy makers take account of the AEMC's preliminary findings as part of the legislative program introducing CPRS and CRET.

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[17] Industry estimates prepared by energy analytic firms, IES, ACIL Tasman, CRA, Frontier and NETTs are estimating the size of the need to be anywhere between $10 billion & $15 billion. Interestingly, environmental groups estimate that the size of the ESAS will be around $1 billion.

[18] BBP considers that such an arrangement would need to be transitional in nature, and should not have any bearing on the expected long term design of the market.

- The extent to which the AEMC considers the need to look for a combined energy and capacity market in the market – a matter that needs to be examined, but also in the context that it is a substantial reform by itself let alone being run in parallel with CPRS and CRET.

- Enhancing existing market arrangements, for instance potential options that could be explored include:

    - lifting VoLL to a level that provides equity and debt holders with greater incentives

    - revising the threshold level for administered pricing upwards

    - allowing the reserve trader option to be used beyond the existing timeframe

    - expanding the scope of ancillary services market

    - addressing key cost recovery mechanisms within the NEM for these services.

Importantly, without a detailed prescription of CPRS and CRET it is difficult to suggest clear alternatives at this stage.

Finally, there is limited liquidity in current forward contract markets. Forward contract prices provide participants with substantial information that is used to decide when to make investments in new generation. Accordingly, the lack of activity and prices provides policy makers with the strongest commercial signal of the market consensus on the level of uncertainty that the market is currently trying to digest. This uncertainty acts as a further dampener on future investment.