ENERGY MARKET FRAMEWORKS

IN LIGHT OF

CLIMATE CHANGE POLICIES

AEMC SCOPING PAPER

A Submission

from

Major Energy Users Inc

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

The content and conclusions reached in this submission are entirely the work of the MEU and its consultants.

EXECUTIVE SUMMARY

Consumers see that the move to introduce the ETS and an expanded MRET scheme is introducing significant uncertainty and at the same time, significant increases in power and gas costs.

At its most fundamental, the structure of the NEM is adding unnecessarily to this uncertainty, from the market trading approach through to the Rules. The MEU considers that a move to a WEM style capacity market permitting bilateral trading will achieve both an increase in the thermal efficiency of the electricity market and reduce uncertainty for investors in new generation. This will assist in mitigating the expected decrease in reliability that the increase in intermittent generation will engender, along with the loss of reliability caused by the likely increase in congestion.

That costs for using energy will increase is expected; from increased costs for gas used domestically having to compete with exports, the cost of carbon mitigation measures, from the plethora of new generation (especially intermittent) having to be built, the augmentation of the shared networks to accommodate the new generation connections, and paying for stranded assets. What is likely is that some large consumers will decide to close operations or relocate off shore, and as a result the contributions they made to the shared assets will have to be carried by the consumers still connected.

The gas market augments its system on a “build to order” approach and this does not allow for spare capacity. There is a need to address this feature of the gas market, perhaps by government providing underwriting for spare capacity.

The incidence of congestion will increase in both gas and electricity markets, and a different approach must be developed, whether by building spare capacity or providing firm access. As network costs will increase, the need to address cost allocation in a more equitable way must be developed, as renewable energy sources are more than likely to be well remote from the shared networks.

The financial crash of 2008 brings mixed blessings. On one hand it will reduce the burgeoning demand for materials and labour, causing a reduction in these costs. On the other hand, it has already brought a more hard headed approach to debt, and so the cost of financing will either increase or the availability of funds for augmentations will decrease.

Overall, the introduction of the ETS and an expanded MRET is a national issue. It is inappropriate for all of the cost to fall on energy consumers and a better socialisation of these costs is essential.

1. Introduction

The Major Energy Users Inc (MEU) welcomes the opportunity to provide comments on the AEMC Scoping Paper on Review of Energy Market Frameworks in Light of Climate Change Policies.

Climate change policies are forms of government intervention in energy markets whose legislative and regulatory frameworks are underpinned by provisions to achieve economically efficient outcomes, with competitive forces and effective regulation (as a surrogate for non-contestable, natural monopoly networks) being the key drivers.

By their very nature, such interventions create uncertainty and risks for major end users, whose investments have been premised upon (and have been encouraged by successive governments in Australia) access to Australia's rich energy endowments which have provided low cost, sustainable energy input prices, especially for energy-intensive industries.

It has been long recognised that low cost energy has been one of the few compensating aspects available to manufacturing to the many disadvantages manufacturers in Australia face. It should be recognised that it was this very access to low cost energy that actively encouraged high energy using manufacturing processes. What is now occurring is that these same processes are seen as being the cause of Australia's high per capita carbon dioxide emissions, and these manufacturers are threatened with closure (or relocation off shore) due to the national drive to reduce greenhouse gas emissions.

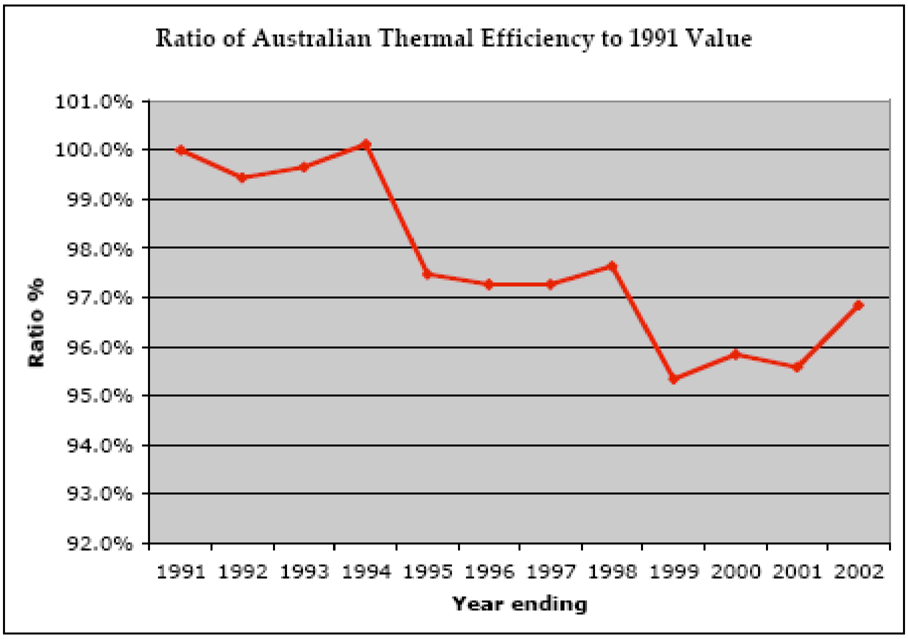
One major impact of causing these large energy intensive industries to close, will be that financial contributions to the use of shared assets will cease, stranding these assets. If that occurs, there will need to be a fundamental change in regulatory practices. Either stranded assets will have to remain within the regulatory asset bases of networks service providers (and thereby increasing the costs for all users remaining connected) or the stranded assets will have to be optimised out of the networks, thereby increasing the risks for network service providers. It will be unacceptable to ignore this fundamental issue.

Climate change policies, with their intervention in market-based decisions, therefore can create a chilling effect on upstream, mid-stream and downstream investments.

It is pertinent to note that the thermal efficiency in the NEM has reduced over time, and as electricity generation is a primary source of carbon emissions, this shows that the approach taken in the introduction of a competitive wholesale market has caused a significant increase in emissions. Thus the market approach itself has contributed to the national problem. Bardak has calculated the loss of thermal efficiency in the NEM and comments (page 55):-

Fig 4.1 [shows] the decline in thermal efficiency (which increases energy costs) [in the NEM[1].

Fig 4.1 Thermal Efficiency in the NEM



It is difficult to ascertain the full range of impacts on energy markets, and hence on the major stakeholders. However, it is possible to suggest for review a number of issues that are likely to have a major impact on energy markets, where the costs of continuing with existing frameworks would be high, and are difficult to address through refinement to existing arrangements. It is also relevant to include issues that are already occurring or would have occurred in the absence of climate change policies, as the distortions will be accentuated by the introduction of the climate change policies.

From the MEU's viewpoint these issues would have a substantial impact on energy prices, reliability, service quality and sustainability.

Section 3 of this submission details the MEU's interests in these four aspects of energy markets.

[1] The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market, Bardak Ventures Pty Ltd, May 2nd 2005

2. About the MEU

The Major Energy Users Inc (MEU) represents large energy consumers operating in the NEM and in other jurisdictions. The MEU comprises some 30 major energy using companies in NSW, Victoria, SA, WA, NT, Tasmania and Queensland. MEU member companies – from the steel, aluminium, paper and pulp, auto and tourism and the mining explosives industries – are major manufacturers in the NEM and in other jurisdictions and are significant employers, and are located in many regional centres.

Analysis of the electricity usage by the members of MEU shows that in aggregate they consume a significant proportion of the gas produced and electricity generated in Australia. As such, they are highly dependent on the transport networks to deliver efficiently the energy so essential to their operations. Many of the members, being regionally based, are heavily dependent on local suppliers of hardware and services, and have an obligation to represent the views of these local suppliers. With this in mind, the members of the MEU require their views to not only represent the views of large energy users, but also those of smaller power and gas using facilities, and even at the residences used by their workforces.

The companies represented by the MEU (and their suppliers) have identified that they have an interest in the **cost** of the energy networks services as this comprises a large cost element in their electricity and gas bills.

Although electricity and gas are essential sources of energy required by each member company in order to maintain operations, a failure in the supply of electricity or gas effectively will cause every business affected to cease production, and MEU members' experiences are no different. Thus the **reliable supply** of electricity and gas is an essential element of each member's business operations.

With the introduction of highly sensitive equipment required to maintain operations at the highest level of productivity, the **quality** of energy supplies has become increasingly important with the focus on the performance of the distribution businesses, because they control the quality of electricity and gas delivered. Variation of electricity voltage (especially voltage sags, momentary interruptions, and transients) and gas pressure by even small amounts now has the ability to shut down critical elements of many production processes. Thus member companies have become increasingly more dependent on the quality of electricity and gas services supplied.

Each of the businesses represented by MEU has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term **sustainability** of energy supplies is required. If sustainable supplies of energy are not available into the future, these investments will have little value.

Accordingly, MEU members are keen to address the issues that impact on the **cost, reliability, quality** and the long term **sustainability** of their gas and electricity supplies.

The members of MEU have identified that energy transport plays a pivotal role in the energy markets. This role encompasses the ability of consumers to identify the optimum location for investment of its facilities, and providing the facility for generators and gas producers to also locate where they can provide the lowest cost for energy supply. Equally, consumers recognise that the cost of providing the transport systems are not an insignificant element of the total cost of delivered energy, and due consideration must be given to ensure there is a balance between the two competing elements.

3. Overview

From an end-user's viewpoint, four broad fundamental sets of issues arise from the introduction of CPRS and expansion of the MRET scheme and the impact on energy market frameworks of these are as follows:

i) Relative prices will change: i.e. between electricity and gas energy prices and electricity and gas network prices, as well as with prices of renewable energy, especially wind;

ii) The balance of incentives and risks in electricity and gas regulatory regimes will change;

iii) The adjustments end users will make as a result of (i) and (ii) above (eg pay the premium, accept the risk, self generate or move away?).

iv) There will be increased need for infrastructure to allow access for new generation, gas supplies and renewable energy. Is this a cost to be carried on a socialised basis (e.g. built into network charges) or attributed to causer pays (e.g. by the connecting generator)?

Relative prices
With respect to (i) above, gas prices will rise relative to electricity prices (as will gas network prices relative to electricity network prices) because of the larger role for gas in the energy supply equation, and the relative reduction in the use of coal for power production. It is quite obvious that the first stage of emissions reductions will result from the greater use of gas for all new power needs. This greater use will come from two main sources – new bulk power stations, but just as importantly, more large users of power will seek to self generate, and this self generation is most likely to come from gas firing.

Gas supply (including CSM) will be constrained and conditioned by LNG exports, which in turn will put further upward pressure on (domestic) gas prices.

Gas network charges will also rise in response to demand, but existing networks are already experiencing capacity constraints. Increased augmentations and new greenfields pipelines will be required.

The current gas pipeline regulatory regime (with its light-hand regulation and greenfields pipeline regimes) would need to be supplemented by government intervention to provide incentives for new investments to meet new demand from new power stations and to have an inter-connected grid. This is because it has been seen that there is a clear lag between the need for incremental augmentation and completing new pipeline investments. Historically, governments have acted to ensure there is capacity available for increases in demand **prior** to the need. In contrast, existing pipeline operators are definite in that they need to have committed (and paid for) contracts in place before they will augment the supply arrangements. This means that the current approach whereby new pipeline proponents will only build capacity only if there is sufficient load will not be adequate. This raises the question as to whether government take a lead role, fully or partially, in underwriting new pipelines. This issue is what has been seen in WA where the actions of the owners of the DBNGP in their augmentation practices have resulted in a significant lag in providing increased gas supplies causing many end users to cease using gas for their needs and reverting to other forms of fuel, such as coal. This augmentation lag issue is likely to become a widespread issue as gas usage increases. The MEU considers that the concept of "allowing the market to solve these issues" is likely to be insufficient for the expected massive growth in gas usage for power generation.

Overall, the cost of power will increase as gas firing is more expensive than coal firing. The current electricity trading system will be further exposed to price spikes – many renewable sources of power are intermittent such as tidal, wave, solar and wind power resulting in a reduction in load factors and a resulting increase in price – and volatility, thereby increasing risk premiums. The cost of supplying back up power for intermittent generation will further increase costs and these will have to be recovered in short term generation, increasing spot prices and exacerbating price spikes.

A significant factor will be an outworking of the need of retailers to manage risk. Retailers will expand their programs of self management of this risk by building their own generation, most likely based on gas.. This will accelerate the integration of generators and retailers, encouraging further consolidation of the supply industry and increasing the industry's market power. Dual-fuel and multi-fuel integrated businesses will, as a result, wield very significant market power.

As has been pointed out in the AEMC's stakeholder advisory Committee meetings, an energy only market requires:

- Robust competition;
- Minimal vertical integration;
- Liquid contract market

Already we are seeing the current credit crunch exacerbating these issues.

Incentives and risks

With respect to the impact of incentives and risks (see (ii) above) we need to examine these from the perspectives of generator/producer, network operator, and retailer, as well as an end user.

Generator/Producer

Merit order despatch processes will need to change as intermittent generators have already been seen to disturb current practices and this can distort the spot market for prolonged periods, leading to greater volatility and market risk.

Congestion has increased where intermittent generation is connected. Intermittent generation is a "price taker" and is dispatched regardless of system demand. We have already seen some locations where schedulable generation has had to relocate as its ability to be dispatched has been significantly curtailed due to intermittent generation taking priority access to the network, causing the schedulable generation insufficient revenue to retain its location.

Generators currently pay shallow connection charges. Gas fired generators are likely to locate close to loads but there should be incentives to encourage such actions; geothermal, wind, solar, wave and tidal power are unlikely to be close to load centres, and therefore there will be a need for the power to travel long distances to service the load. This raises the basic question as to who pays for deep TUOS costs. Currently, generators pay for connections to the shared network, but the distances involved will cause many of these generation options to become uneconomic if they have to pay, and defeating the purpose of the planned changes. The MEU considers that consumers should not pay for these features as the cost results from government fiat. There is an argument that these costs should be socialised, but this then raises the question to what extent should the costs be socialised.

- How much should a generator pay before the costs are socialised?
- Should some generation types be exempt from connection costs, but others not?

- How should the socialised costs be recovered – from consumers or tax payers?

<u>Network operators</u>

Should consumers be required to pay under current chapter 6 Rules, then consumers will be up for massive capex costs (especially to link with remote renewable generation). Other than the need to pay for connection costs, the current AER guidelines do not send pricing signals to co-locate new generators near to load, with consumers bearing all risks and associated costs.

<u>Retailers</u>

Non gentailers will face a competitive disadvantage vis-à-vis the vertically integrated gentailers or dual fuel and multi-fuel retailers, resulting in a reduction of retail competition. Already consumers are seeing the impact of this need for retailers to have some generation capability to mitigate the market risks.

Liquidity in market trading is likely to diminish (in the base market, the secondary trading market and the futures market), further increasing risks and as a result costs to consumers.

<u>End users</u> will face more risks and costs e.g.:

- They will pay for more network augmentations and new investments
- The current generation mix will change the risk profile significantly, and costs will rise.
- There will be greater reliability and volatility issues with more renewable generation, with potentially lower service quality and less reliability
- Less liquidity in the market will increase pool exposure risks for users
- Wide swings in the spot market will disadvantage consumers negotiating for contracts
- Energy-only market is likely to accentuate reliability and quality of service problems.

Large end users are already making adjustments to climate change policies and their impacts on energy markets and encouraging actions such as:

i) On-site self generation (by-pass risks for network and generators and leading to assets stranding)

ii) Power pooling by users (by-pass risks and, reducing spot market liquidity).

The outcome of large consumer actions will have a significant impact on the revenues of network providers and the market as a whole. To manage these changes will require new Rules for connection to grid and perhaps allowing for bilateral contracting.

Small end users will move towards greater self reliance (eg solar hot water heating, micro solar power generation) negatively impacting network utilisation and a need to reallocate costs to those users not involved. This, in turn, has the potential to cause greater costs on those small users least able to pay.

Increased infrastructure

There is no doubt that the approaches to address climate change will result in an increased need for infrastructure, whether this results from a lower load factor for energy transport or the need to connect to more distant, and a greater number of, new energy sources.

Whilst the need to connect to more distant and a greater number of new energy sources is a very clear outcome of the ETS and MRET policies, the main issue becomes one of how the costs are to be allocated – to the energy source, to the consumer or more widely socialised, or perhaps a mix of all three.

The less obvious issue is that there is no doubt that the load factor of the energy transport assets will reduce as a direct outcome of the policies. The load factor will be impacted in a number of ways:-

- Renewable energy supplies tend to be relatively lower in output from a single location than the traditional coal fired generator. That is there will be a greater number of renewable generators each with smaller connection capacities than from a single large coal fired power station, with a resultant loss of economies of size.
- Intermittent generation will reduce the load factor because when the intermittent generation is operating the utilisation of the back up dispatchable generation connections will be under utilised. When the intermittent generation is not operating their connection assets are idle.

- With an increasing use of gas for power, the pipelines will show a reduction in load factor as the gas supplies will need to match the power demand. The ratio between peak power and minimum power is about 50%. ie the minimum power demand in the NEM is about half the peak power demand. To accommodate this variation in power demand, gas supply systems will have to be sized to manage this wide demand profile.
- Most large energy consumers use energy consistently and continuously. As price pressures drive large consumers to their mitigating options, the smoothing effect of these flat loads will be lost, exacerbating the lessening load factor
- Small consumers will be driven to self supply options, reducing their dependence on conventional supplies. As the most common of these is solar, small consumers will be seeking backup supplies when the solar options are not providing for their needs. This will result in a reducing load factor between day and night needs and winter and summer needs.

Already, consumers are seeing the impact of infrastructure assets showing signs of wear. Consistently, consumers see applications to regulators from infrastructure owners seeking greater and greater allowances for capital to “replace ageing assets”. In a number of ways consumers are seeing the outworkings of this ageing process (both in transport and producer/generator assets) in two ways:-

- As assets trend towards greater unreliability and having increasingly more frequent downtimes, consumers see the outworkings of this effect with more frequent losses of supply.
- Rapidly increasing costs for the provision of services with the same or reduced reliability and quality of supply

In particular, gas consumers are seeing increasing requests (especially in NSW) for gas demand curtailment as the networks and producers struggle with providing a consistent high quality and reliable supply. The impact of increasing the use of gas for power generation and the fall off of coal fired generation, is going to increasingly stress the existing assets which are already showing stress.

The inevitable outcome for consumers will be greater cost for providing the services but with a reducing quality and reliability of supply, which in turn has the impact of increasing costs of production for end users of gas. If costs increase, then either prices will rise, making end users less competitive, or force them to locate elsewhere.

SPECIFIC QUESTIONS FROM AEMC SCOPING PAPER

This section provides the MEU's response to the AEMC's specific questions. The responses are based on and are derived from the observations included in previous sections – these observations provide a more detailed explanation for the MEU responses provided below for each specific question.

A. Convergence of Gas and Electricity Markets

	AEMC question	MEU response
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?"	Overall, the gas markets will not readily adjust to the emerging needs. Already, we are seeing significant challenges and accommodations having to be made in developing the short term gas trading markets for Adelaide and Sydney. The large increase in demand for gas will overload the existing gas transport assets (already there are signs that assets built in the last decade are approaching capacity (eg EGP) and therefore requiring considerable augmentation to handle the expected increases. The gas market is structured on "building to order" rather than building significant spare capacity, and the current gas market Rules have been shown to be inadequate for providing capacity ahead of need and as a result consumers are moving away from gas. Government intervention in the form of underwriting spare capacity might be required. We have already seen arbitrage activities (particularly caused by gas supply for electricity generation) causing the loss of supply to major users (as seen in NSW in July 2007) Market power ability of dual fuel gentailers and producers will increase, causing a loss of competition with resultant higher prices.

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?”	There are a number of issues that need to be examined in detail • Government ownership of electricity assets is already seen as a major issue within the electricity market. Introduction of competition to these has been negatively impacted and could cause new entrants to defer investment • Increasing concentration of energy businesses has already been identified and with the high costs to operate in the new environment and the high cost to provide risk management is providing a large barrier to entry. The problems in the SA market shown in the summer of 2008, due to increasing concentration of the retail and generation elements, will be replicated in other States. • Differences in regulatory regimes between electricity and gas will cause a disconnect in the risks faced e.g. electricity transmission networks are fully regulated; gas transmission pipelines have a range of approaches, including no regulation. The costs to manage the disconnect will be significant. Gas pipelines are now being “built to order” with little spare capacity, so that pipeline owners can avoid the regulation impact of third party access to spare capacity. This is not an issue for the electricity transport system which has open access.

B. Generation Capacity in the Short Term

	AEMC question	MEU response
3	What are the practical constraints limiting investment responses by the market?	The most important issue is the timing lag between market signals and investment completion (this has been referred to above as the DBNGP issue). The many uncertainties that abound in the

		market are constraining investment e.g. CPRS, government ownership, gas and electricity regulatory regimes convergence. The forecasts of early retirement of coal fired plant (especially brown coal) despite the pragmatic view that such power plant cannot be retired without major impacts on reliability and continuity of power supply. There is a consistent focus on the investment needed for the transport assets. But the increasing costs are having an impact on investment both upstream and downstream and these need to be recognised. Large users of energy will look to options to either reduce their costs or close. Either way these actions will have an impact on those remaining connected to the energy transport assets. This will have a major impact. At its most fundamental is the concern about the ability to pay for the impacts of the large investments needed in gas fields, the gas transport assets, the new lower carbon emitting power stations, the cost of fuel for these, the cost of the renewable generation assets and the impact of the need to significantly augment the electricity transport assets to accommodate the changes.
4	How material are these constraints, and are they transitional or enduring?	It is expected that the augmentation costs on the energy transport assets will be extraordinarily large. Already, consumers are unhappy with the large increases in using energy transport services, mostly caused by the espoused need to replace ageing assets. The cost that will be incurred by the augmentation of the electricity and gas assets will be much larger than the current cost increases. The costs to consumers for augmentation are enduring as the assets that are needed will have a life span of 50-100 years. The

		market system used is that the costs for using the services are based on a return on the assets provided and a replacement of the capital used to provide the services. Further the provision of the gas assets currently is based on "build to order" and therefore augmentation of the assets will be a continuous process. One way of limiting this effect, is for government to fully or partially underwrite the provision of significant spare capacity.
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?	Already, we are seeing system operators act to prevent loss of supply because of congestion. Increased congestion is an outworking of the increase in the number of generation sources, the degree of their intermittency and their remoteness from load centres, so the likelihood is that intervention will increase rather than decrease, and the current level is too high now. We expect there is a greater likelihood of market failure and disruption of supply. Again, these effects are already being seen, and an increase is unacceptable. Wind generation especially is already identified as being highly unreliable and causing major dis-equilibrating impacts on spot market. Any intervention in a market is inefficient and so it is to be avoided. The system operators have been quite successful to date in managing the markets, so there is an expectation that they can effectively manage the problems that do occur. The issue is whether the extent of the need to intervene can be adequately managed as the incidence of the need to intervene increases. Ultimately, there will be a point at which intervention will not be effective.

C. Investing to Meet Reliability Standards with Increased use of Renewables

	AEMC question	MEU response
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?	Any reduction in reliability of the gas and electricity markets will cause significant financial pain to end users as reviews of VoLL have identified. An increase in intermittent generation will increase the risk in reliability of supply and potentially provide market distortions. Counteracting this is the benefit of diversity that multiple generators in different locations bring. The greater the reliance on intermittent generation, the greater the need for back up supplies of power. If these back up facilities fail, reliability falls. The occasional use of backup supplies increases the potential for failure. A plant used occasionally is less reliable than one used regularly. The occasional use of backup supplies also increases the cost to provide these, reducing the potential for investment in back up generation. The need to provide back up supplies for intermittent generation will increase the cost for providing power for the market, raising the issue of who should pay for the reliability needs for an intermittent supply.
7	What responses are likely to be most efficient in maintaining reliability?	With the small amount of intermittent generation operating in the NEM to date, there has not been an adequate opportunity to assess whether the current market operations will extend to providing adequately for a large expansion of intermittent generation. Market signals are essential for the optimum operation of the NEM/WEM. There is no basis on which to assess whether the current arrangements will provide sufficient support to ensure

		reliability will be maintained in the market where the impact from such a large expansion of intermittent generation is planned and will be so widespread. It may be necessary in the transitional phase for there to be government intervention to ensure there is adequate backup generation to match the amount of intermittent generation until the full effects can be identified. It has been observed in the WEM (a capacity market permitting bilateral contracting) that investment in new generation is proceeding very well – this is in stark contrast to the NEM where generation investment is relatively slow, despite market signals indicating a need. What end users are seeing is that investment in new generation requires a high degree of certainty in the market prices. Where average market prices are heavily inflated by a small number of very high price spikes (for example about 20% of the average regional prices are derived from prices applying for less than 1% of the time), this creates uncertainty about future long term pricing. As a result, new generation in the NEM is primarily low cost open cycle gas fired generation, rather than the higher priced but more efficient combined cycle generation. CCGT generate much less carbon emissions than OCGT generation. The MEU considers that a serious examination of a capacity based bilateral trading market might be more appropriate for the NEM to achieve the national goal of reducing carbon emissions.

D. Operating the System with Increased Intermittent Generation

	AEMC question	MEU response
8	How material are the challenges to system operations following a major increase in intermittent generation?	This question cannot be answered without the necessary experience of attempting to operate with such a high proportion of intermittent generation. The critical issue is to identify the extent of spinning reserve in each region to match the extent of intermittent generation. Experience may show that different levels of spinning reserve will be needed in different regions. Some overseas jurisdictions have some experience and this needs to be examined to assess its applicability for the different Australian regions. It is expected that merit order despatch will have to change, and there will have to be identified sufficient spinning reserve to support the amount of intermittent generation operating in each region at any one time. The major issue is that the introduction of such a large proportion of intermittent generation will result in there being significantly reduced efficiency in the market. It has been noted that the competitive market has seen a reduction in thermal efficiency in the NEM. The dispatch process itself has led to this outcome, and so system operations need to recognise that it is a primary cause of carbon emissions
9	Are the existing tools available to system operators sufficient, and if not, why?	As there is no experience in operating the Australian markets with the expected amount of intermittent generation, that there is no certainty that the current tools will be adequate. On this basis it is considered that there probably is not. A review should be made

		of overseas experience where there is a significant share of intermittent generation (comparable to the amounts expected in the different regions) to identify if this is an issue, and what tools are used. There will be a need to assess whether these tools are applicable to the Australian conditions expected.
10	How material is the risk of large scale intervention by system operators and why might such actions be ineffective or inefficient?	The loss of supply is recognised as the major risk for consumers in the energy markets. In this regard, it is not so much that a failure might occur, but if it does occur, the widespread loss to the community as a whole, and to end users in particular, is likely to be catastrophic and cost well in excess of the potential savings by not addressing the issue. That this is so is typified by the market, policy makers and regulators that consumers should pay a premium for securing reliability rather than pay the minimum price for service. With this consideration as a top of mind issue, if there is a risk that reliability might suffer as a result of the need for intervention, then conservatism is essential. The need for intervention results from market failure. If there is a risk of market failure and therefore the need for intervention, then this demonstrates an inefficient outcome. That intervention might be effective is the desired outcome but at this stage, with all of the unknowns applying, it would be a brave decision to assume that should intervention be required that it will be effective.
11	How material are the risks associated with the behaviour of existing generators, and why?	In SA and NSW, there has been the blatant exercise of market power by generators. That generators will use market power to increase their revenue cannot be doubted, and indeed, privately owned generators must use such power if possible or fail in

		their duty to their shareholders. The introduction of a large fleet of intermittent generators will create an opportunity for incumbent and dispatchable generators to increase their revenue. The more risky the market becomes the greater the opportunity for generators to change their behaviour to increase prices, and even exercise market power at times. In the event of a significant gas shortage (and these occur quite frequently), gas fired generators will compete with end users for access to a scarce resource. Whilst a short term gas trading market (STTM) will provide a little management in allocating gas resources, the STTM only applies at the regional hubs, because most gas fired generators and a number of large gas consumers will operate outside the hub. Thus there is the expectation that as the power and gas markets become more exposed to the impacts of increased intermittent generation, the result will be for major risks of gaming as well as system failures. We expect that non-integrated, single fuel businesses will be especially exposed to these risks, and as a result will make entry to the markets more difficult to manage.

E. Connecting New Generators to Energy Networks

	AEMC question	MEU response
12	How material are the risks of decision-making being "skewed" because of differences in	The Australian markets have never been tested with the increased risks that the introduction of the ETS and expanded MRET scheme will provide. The risk is that market responses in the short term will be likely to be inadequate, and as noted

	connection regimes between gas and electricity, and why?	earlier, the risk of market failure is significant. It has been noted that the gas transmission market is dedicated to avoid regulation. This is achieved by "building to order" and not having excess capacity available to be available for third party access seekers. In counterpoint, the electricity system is open access to all capacity and there is no reservation of capacity available to users. The MEU considers that this difference will cause a delay in introduction of new gas fired generation to meet the power market needs.
13	How large is the coordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation?	It is necessary to examine the connection of gas and power separately. In relation to gas, there will be lags in market responses arising from the need to "build to order" and the bilateral negotiations surrounding connections, and there being no spare capacity being available for any augmentation. The issue is likely to be widespread therefore the time and resources constraints will have an impact. In contrast in the electricity market, the Rules require negotiation for all new connections, including the costs for any augmentation to the shared network which do not deliver any degree of "firmness" to capacity. Direct experience in negotiating augmentation connections to the shared network shows that the service provider has a monopoly on augmentation/connections. And this monopoly power is used. The electricity Rules do allow arbitration by the AER and it is expected that with the large number of augmentation/connections that will result from the changes, there is a real risk that the AER will not be able to manage the volume of arbitrations that are

		likely. This problem is seen as a transitional one, but despite this it has the potential to cause large cost burdens well into the future, and therefore the impact is a long term cost to consumers. It is recommended that the AEMC look closely at the value in maintaining the need to negotiate and examine the benefits of reverting to the original approach where such augmentation/connections are viewed as augmenting the shared assets.
14	Are the rules for allocating costs and risks for new connections a barrier to entry, and why?	Yes. The Rules are different for electricity and gas with the electricity Rules clearly having the causer paying. As noted earlier, this will disadvantage remote generation and cause a disincentive. The electricity Rules attempt to limit socialisation of costs, but in doing so distort the ability of new generation to access the market. The electricity Rules also do not provide firm access to the shared network. Thus is a number of generators connect at the same point (or even near each other) there is potential for congestion effectively preventing some generation from accessing the network, even if they have incurred significant cost in connection. A new generator accessing the network is potentially liable for paying for the augmentation of the shared network to allow it access, whereas incumbent generators avoid this cost. With the need for significant new generation under the ETS and MRET, this issue will be a major issue to achieve the aims of the emission reductions. As the ETS and MRET are government intervention, it is inefficient for these costs to be recovered from consumers, as they did not cause the need. Further, such an approach is likely to drive more end users from the market, imposing more costs on

		the remaining users. As discussed earlier there is a need to develop a cost allocation approach which retains some incentive for new generation to locate in the optimal location, not drive end users off the market, and to allocate costs on a socialised but wider basis reflecting that carbon emission reduction is a national issue. The allocation aspect of the gas Rules is being circumvented by "building to order" and thus effectively eliminating third party access, and the associated cost allocation issues.

F. Augmenting Networks and Managing Congestion

	AEMC question	MEU response
15	How material are the potential increases in the costs of managing congestion, and why?	Congestion presents major risks for investors and users. As noted earlier, the impact of congestion is already creating concern, and with the advent of increased generation, the issue is going to get worse Any impact on reliability is an issue for users, as the costs for loss of supply are greatly outweighed by the costs inherent in its provision. Currently, congestion is paid for by consumers whether this is a result of regional separation or out of merit order dispatch, although some generators also face costs by not being dispatched when able to do so. Currently unscheduled (usually intermittent) generation gets dispatched first in preference to scheduled generation, and this is likely to occur more often as the amount of intermittent generation increases. This will result in greater

		congestion and therefore costs.
16	How material are the risks associated with continuing with an "open access" regime in the NEM?	From a generator's point of view, the costs of connection are significant, particularly if the shared network needs to be augmented to allow dispatch. To have to pay for augmenting the shared network but get no benefit in terms of firm access creates a disincentive for investment. The MEU has a preference for a simple network regulatory and pricing regime to reduce the time needed to provide new investments, and provide efficient cost allocation.
17	How material are the risks of "contractual congestion" in gas networks and how might they be managed?	The issue of "contractual" congestion in the gas market is a result of the "build to order" approach to providing gas transport. Although there is often "interruptible" capacity available in a pipeline, this is not sufficient basis to invest in new generation. Unless there is firm capacity available new gas fired generation will not be built. This makes this issue material. There is needed an approach to allow pipelines to build in adequate spare capacity for future needs as governments did when they were responsible for gas transport. The MEU recommendation is that with each new gas pipeline, governments provide underwriting for a significant element of spare capacity for future needs. This replicates the role of government in previous years.
18	How material is the risk of inefficient investment in the shared network, and why?	Very material. Currently the pricing policies in the electricity Rules (and as imposed by AER guidelines) are not required to be cost reflective. As a result, users are adjusting their operations in response to these inefficient price signals. If the pricing signals are inefficient, then the investment

		in the network will be inefficient. Currently the electricity Rules do not require optimisation of the networks, so the costs of inefficient investment are socialised
19	How material is the risk of changing loss factors year-on-year?	This is a major issue, and the variation year on year creates uncertainty. The loss factors can and do vary by >5% between years, as a result of different generator scheduling. For large users this cost variation can be measured in $ms between years, and a similar impact is noted for generator loss factors. With increased intermittent generation the loss factors are likely to vary even more year on year dependent on the totality of extraneous factors. The more remote the generation is, will increase losses for such generation, adding to the disincentive embedded within the electricity Rules for this class of generation.

G. Retailing

	AEMC question	MEU response
20	How material is the risk of an efficient retailer not being able to recover its costs, and why?	It is necessary to differentiate between "gentailers" and second tier retailers. Gentailers should be able to manage their retail costs more effectively than second tier retailers. For second tier retailers (non-gentailers and non dual fuel retailers) their risk will be much greater as they rely more heavily on being able to secure independent generator hedges (primary market), and risk management from the secondary market (with liquidity in the secondary market being a major issue).

		If the markets are illiquid, there is the risk they will not be able to manage their risks at all. The alternative is that the cost for them will be too high to remain competitive. Large end users are already experiencing a lack of competition between retailers, with gentailers being more likely to remain in the market. End users have seen generators being prepared to offer less capacity into the market – the reason cited is the market is becoming too risky for generation. This could be overcome by moving to a WEM style market, with capacity payments and allowing bilateral trading.
21	What factors will influence the availability and pricing of contracts in the short and medium term?	There are a number of ways that forward contracts can be encouraged • Gas availability for domestic market rather than exporting • government intervention to create incentives; • government ownership (especially for generation) needs to be removed. • Removing uncertainty • Reducing volatility in the NEM • Move to a WEM style market • Firm access as congestion creates increased risks raising risk premiums, and reducing liquidity
22	How material are the risks of unnecessarily disruptive market exit, and why?	Market exit risks by generators are substantial as the result is a shortfall in generation capacity and/or a significant increase in prices. It is unlikely that large generation will exit the market if the owners consider they can continue to make a profit, even if the value of their investment falls Probably more disruptive (and more likely as costs rise) are exits by large users. Large users pay a large proportion of network costs – their exit will require these costs to be carried by less consumption increasing cost to those still using.

H. Financing New Energy Investment

	AEMC question	MEU response
23	What factors will affect the level of private investment required in response to climate change policies?	Current global financial crisis will create a financing fog for some time until the market settles. Financial engineering and hybrid finance are now historical (and discredited) models: Regulatory regimes still fail to signal new investments. The risk to consumers is that financing costs will be higher thereby increasing costs. There is already a backlog of equipment supplies needed by networks and generators. The changes implicit in the ETS and MRET will exacerbate this, increasing costs for new equipment and the cost for the investments planned. Overlaying this will be the attempt to build new infrastructure in a short time frame, driving up construction costs for the new infrastructure. The higher the cost for the new infrastructure the greater the risk to the investor as greater certainty of a return is required to underpin the higher value of the investment.
24	What adjustments to market frameworks, if any, would be desirable to ensure this investment is forthcoming at least cost?	There is a need for short term government intervention. Market-based solutions will be inadequate to address such a substantial form of intervention (CPRS and MRET). There needs to be greater control on networks investments to minimise unnecessary expenditure, and focus only on what is necessary (e.g. currently networks are replacing assets just because their economic life is complete, yet the asset is still capable of providing the service. This replacement program is being driven by the regulatory regime.)

		Greater certainty of gaining a reward from the investment is required, and a move to a WEM style capacity market with bilateral trading would provide this greater certainty.