Australian Energy Markets Commission

AEMC SECOND INTERIM REPORT

ON

REVIEW OF ENERGY MARKET FRAMEWORKS

IN

LIGHT OF CLIMATE CHANGE POLICIES

Submission by

The 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.

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Executive Summary

The Major Energy Users (MEU), representing many large energy intensive trade exposed manufacturing industries located in the NEM states, Western Australia and the Northern Territory, provides its comments on the AEMC's 2nd Interim Report.

The MEU is disappointed with the AEMC's Report and the reason for this assessment is contained in Section 1 of this submission.

The MEU considers that the Report is inconsistent with the National Electricity Law (NEL) Single Market Objective. The AEMC's analytical framework deals only with "reliability" as its fundamental assessment point, and as a result, contains analytic omissions, such as the impact of its recommendations on the prices consumers will have to face in the light of the consequences of Climate Change policies on energy market frameworks. "Prices" are a key outcome as encompassed in the NEL's Single Market Objective. Yet, the AEMC's Report foreshadows several layers of additional price increases, as a result of CPRS and xRET, viz significant increases in VOLL with its attendant increases in risks, volatility and prices; consumers to pay for stranded assets caused by generators being used less and/or shut down as a result of CPRS; and consumers to pay for an innovation mechanism for distribution networks.

Key concerns raised by the MEU, and other stakeholders, especially in relation to the energy-only market, and its ability to accommodate massive distortions in the form of CPRS and xRET interventions have received little or no recognition. Concerns with the current lack of vigorous competition in the NEM, the increasing concentration of the energy supply industry (especially retail and generation), the increased volatility, risks and potential arbitrage activities, and the price outcomes that are neither optimal nor efficient (and will become worse with the introduction of CPRS and xRET), have received no recognition, let alone been debated.

The AEMC's Report often refers to achieving "efficient prices", but it has produced no empirical evidence or analysis to demonstrate that the NEM has produced "efficient" outcomes in terms of generation, transmission and distribution, let alone that these are the likely outcomes post introduction of Climate Change policies. And by ignoring the concerns raised by consumers and other stakeholders, the AEMC's Report fails to detail options to create increased competition in the NEM; options to deliver more efficient generation, transmission and distribution; and options to ensure the "long term interests of consumers" including the delivery of more efficient prices.

The MEU observes that the AEMC effectively considers that the WEM would appear to provide a more stable environment to accommodate the CPRS and xRET; yet rather than identifying the aspects of the WEM that lead to this outcome, the AEMC appears to prefer a more risky process by creating distortions to the NEM design to accommodate the impost of CPRS and xRET.

The MEU suggested to the AEMC that an approach of looking at alternatives to the NEM design might provide a better solution for consumers (as required by the NEL) than just "tweaking" the current design by the addition of more distortions and interventions, but the AEMC has refused to even consider such an approach.

The MEU considers that the AEMC's report, if accepted by the MCE, will deliver a dismal future for energy intensive trade exposed industries in this country.

1. Overview of AEMC's Second Interim Report

The MEU is disappointed with the AEMC's Second Interim Report. It is a Report that not only fails to debate the issues of concern legitimately raised by consumers (especially on electricity), but through its single-minded perspective of viewing its review as solely focused on reliability, it has the ability, if its recommendations are accepted by the MCE, to deliver a very dismal future for energy intensive trade exposed manufacturing industries in this country.

In every feature of the AEMC's Report, "reliability at any price" is the outcome. "Efficient prices" are always asserted as the potential outcome, but the empirical evidence and the required analysis to demonstrate that, is not presented. This situation – supply of generating and network capacity at any price – is neither optimal nor efficient, and as a result, fails to meet the electricity market objective of securing the best outcome in the long term interests of consumers.

The single National Electricity Market objective (SMO) is stated in the National Electricity Law (NEL) as follows:

> "To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) Price, quality, reliability, and security of electricity; and
> (b) The reliability, safety and security of the national electricity system."

In other words, there are a range of outcomes within the SMO, including "price". "Reliability" is one key aspect of the SMO.

The Hon. J.D. Hill (for the Hon P.F. Conlon, Minister for Energy) in introducing a Bill for an Act to amend the National Electricity (South Australia) Act 1996 on 9 February 2005, stated:

> "The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.
>
> The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense, the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised."

> "Applying an objective of economic efficiency recognises that, in a general sense, the national electricity market should be competitive, that any person wishing to enter the market should not be treated more nor less favourably than persons already participating in the market, and that particular energy sources or technologies should not be treated more nor less favourably than other energy sources or technologies".

The MEU contends that the introduction of CPRS and the expanded RET will introduce significant distortions to the energy market and therefore its framework (particularly with respect to electricity) needs to be adjusted, as neither of the introduced distortions are neutral in terms of technologies and participants.

In discussions with the Chairman of the AEMC, it was pointed out to MEU representatives that the AEMC is only required by the MCE to identify if the CPRS and xRET legislation changes can be accommodated within the current market structure. We acknowledge this but we also point out that the AEMC also has a requirement under the National Electricity Law (NEL) to ensure that changes (especially significant changes stemming from climate change policies being imposed on the energy markets) made to the electricity market are economically efficient so that the long term interests of consumers are best provided for.

The imposition of CPRS and xRET legislation will significantly distort the electricity market. The AEMC itself points out that there will be significant costs on consumers to accommodate the changes it recommends. Such increased costs relate to changes in VoLL, augmentation of networks, and innovation funds for distribution networks. Thus in addition to the headline costs for CPRS and xRET the AEMC is recommending that the market (ultimately consumers) will have to bear significant increases in additional costs for the market to absorb the CPRS and xRET. The AEMC whilst not calculating this price shock, imply that the costs will be very large, but that regardless of these increases, the prices will be "efficient". With such cost imposts, it is totally unacceptable for the AEMC to not assess whether a different market structure or changes to the existing Rules proposed by consumers (e.g. to strengthen competition or to reduce volatility, risks and economic withdrawal of generating capacity, or to minimize the opportunities for arbitrage between gas and electricity) could deliver the goals of the CPRS and xRET legislation, and concurrently reduce the costs that consumers will incur as a result of the integration of the CPRS and xRET.

The AEMC has continued to ignore the concerns raised by consumers concerning the very substantial increases in costs that consumers will face resulting from its approach focused on achieving reliability, but not on issues, such as, for example, changes to existing Rules to reduce risks and the associated costs that consumers will face in light of CPRS and xReT and the AEMC's new proposals.

For example, if the current structure when accommodating the new CPRS and xRET legislation and the AEMC's new proposals is less economically efficient than an alternative structure with the same impositions, then the AEMC would have failed to ensure that it had provided the most economically efficient outcome to accommodate the changes imposed.

Because the AEMC has failed to even examine any alternative market structures (beyond just the energy only market) despite the clear requirement of the NEL to ensure the most economically efficient solution and the concerns expressed by consumers (and other stakeholders), then it has not complied with the requirements of the NEL to ensure that the outcome it recommends to MCE is the most economically efficient solution to integrate the CPRS and xRET legislations into the electricity market. In this regard, it is interesting that the AEMC highlights that a number of issues seen in the NEM do not arise in the WEM. Analysis of the WEM design shows that the AEMC has identified that a number of aspects of the WEM design actually provide a more stable outcome for consumers when the CPRS and xRET are imposed on the electricity markets. It is extremely concerning that the AEMC has not looked to the WEM to identify potentially better solutions than those recommended by the AEMC for the NEM.

The outcome of this failure by the AEMC and its Report is likely to impose large deadweight losses on the Australian economy.

The analytical framework adopted by the AEMC Review is achievement of "reliability". And if this is capable of being achieved at any price within the current energy market framework, the outcome of this process has been assumed by the AEMC to be "efficient". Such an approach is clearly insufficient when seen in context of the SMO. More disconcerting is that the evidence for "efficient" outcomes claimed by the AEMC is never provided. There is <u>no</u> empirical evidence provided and there are analytic omissions in the AEMC's work, with its sole focus on "reliability", and the practice of using "conditional assumptions" and "straw men".

The MEU has substantiated its concerns with the current electricity market framework and provided in its submissions the following aspects that concern consumers:

- The NEM is increasingly concentrated, with fewer and dominant players, and with the creation of vertically integrated businesses. The assumption of rigorous competition in wholesale and retail electricity markets is invalid.
- The exercise of market power by generators in recent times cannot be considered as transient and there have been substantial economic damage caused as a result of this exercise of market power
- The NEM is highly volatile, risky and costly, and the expectation of CPRS and xRET has increased the impact of these

- Barriers to new entrants are higher, and increase the opportunities for inefficient price outcomes in the NEM.
- Prices are unrelated to the cost of production and contain ever rising proportions of economic rent
- The NEM is remarkably illiquid, thereby making it difficult to manage risks
- The NEM has not provided long-term contracts – most consumer contracts are now less than 3 years whereas ten years ago, 5-10 year contracts were common
- Lack of a competitive mix of generating capacity, as the signals only incentivize gas peaking capacity
- Unbalanced network Rules (stemming from the AEMC's Chapter 6 transmission revenue rule changes) and the lack of transmission pricing signals, are producing significant increases in network charges (see especially the latest NSW network pricing review outcomes).

Despite these concerns raised, the AEMC lightly dismisses them as largely due to uncertainty about carbon pricing and/or due to temporarily tightening markets.

Having asserted that the current market framework is "robust", the AEMC proceeds along the lines that some "tweaking" of the market framework will allow it to remain "robust" post the introduction of Climate Change policies.

The MEU is concerned that introduction of such massive distortions into the market framework will create further distortions and lead to non-efficient market and price outcomes. Yet despite these concerns being raised, the AEMC has not attempted to establish whether there is a basis for the concerns and remarks that it is the responsibility of those with the concerns to prove they are well founded. In the absence of any detailed assessment, the AEMC relies on a view that the current market structure is the best and requires to be "persuaded" that this is not the case, despite the CPRS and xRET distortions being imposed on the existing energy frameworks.

Its whole approach is to raise the VOLL to signal new capacity and hence reliability. As the MEU has pointed out *ad nauseam*, this outcome is neither optimal nor efficient.

The MEU's concerns are that retaining the current basic structure with the added distortions of CPRS and xRET the NEM will be:

- Even more volatile, and risky, and costly
- Even more difficult to manage risks
- Enhance the opportunities for arbitrage (across gas, electricity and wind) and the exercise of market power.

Despite these concerns being raised by consumers in the AEMC committees, in public forums and in formal responses to AEMC, the AEMC has not sought to examine if there are other options providing for a better market structure which will manage the climate change impositions in a more economically efficient way.

For this reason alone, the MEU expresses its great disappointment with the carriage of the AEMC Review, and the attitude of the AEMC in its inability to accept that the concerns of consumers might have validity and must be addressed.

Throughout the remainder of this response to the draft Second Interim Report, the MEU has responded to the specific aspects raised by the AEMC. This should in no way be seen as supporting the AEMC basic premise that it has identified the optimum structure for the electricity market to accommodate CPRS and xRET.

2. Connecting Remote Generation

The MEU agrees with the introduction of the AEMC's proposed model for major remote connections to the transmission and distribution network. As described in the AEMC's 2nd Interim Report, the new framework is to contain the following elements:

- "Early identification of candidate zones by the AEMO and indicative planning of possible remote connection lines by NSPs.
- Following connection enquiries by generators, a detailed planning process by NSPs to identify the optimum size of remote connection assets.
- A requirement for NSPs to publish the results of the planning process to enable stakeholder scrutiny of the forecasts and cost assumptions made.
- An assessment process that requires the AEMO to independently verify the generation forecasts made by the NSP and provides an opportunity for the Australian Energy Regulator (AER) to disallow the project.
- Construction of the connection asset and agreement on revenue recovery following connection applications by generators.
- A charging framework that requires connecting generators pay for the share of NERG assets they use. Customers would pay for any revenue requirement not recovered from generators if there were fewer generator connections than planned for". (AEMC, page 16).

The MEU is, however, concerned that the framework contains only high level principles, with the details to be left to the AEMO and the AER, especially in relation to the principle of consumers paying for the surplus capacity to be built. Consistent with the MEU's concerns that this AEMC review has persistently ignored consumers' concerns about costs increases, the AEMC's approach here is to leave the risks and the associated costs to be paid for by consumers to another time.

At the working group discussions on this issue, issues were raised on how to define how much surplus capacity was appropriate to be built and how the costs would be allocated, but it appears that these issues are to be left with AEMO/AER.

Another issue concerns how AEMO/AER are to decide whether one option for a combined generator connection asset can be compared to another option in a different area with differing generator types proposing connections (i.e. an issue of trying to pick winners).

Notwithstanding the raising of these concerns – which are substantial ones for consumers, who have to bear the risks and associated costs – the AEMC's 2nd Interim Report has apparently taken the view that these issues are easy to resolve. An alternative construction of the AEMC approach is that the AEMC is only concerned with high level frameworks, and will leave detailed issues for others to address further down the track.

Either way, the AEMC has decided that consumers should bear the costs and risks of its preferred approach. Consumers, of course, face the reality of risks and associated costs, and require certainty in a CPRS/xRET energy market.

In the working group discussions, a very sensible solution was presented by stakeholders along the line that if the requirement for confidentiality could be relaxed (or an open season was allowed), the NSP could work out with potential generators a solution that could overcome many of the above concerns – such as the generators sharing the costs with the existing generators – and could reduce the risk and potential costs to consumers. Such a proposal would still retain the concept that generators should pay for their own connection costs.

The MEU considers, also, that rival proposals for NERG service provision should be permitted. Contestability supports efficient costs being incurred. However, under the AEMC's approach of assigning consumers to pay for surplus capacity, in the event of a non-regulated NSP providing NERG services, existing consumers would be forced to pay even higher costs, should surplus capacity rise.

The MEU agrees with the proposed framework for major remote connections to the transmission and distribution networks, but considers that the AEMC, yet again, has not given sufficient attention to the concerns raised by consumers, who are being required by the AEMC's approach to wear the risks and costs associated with surplus capacity connections.

Alternatives proposed have, apparently met a dead-end.

Contestability in the provision of NERG services is supported as it will help in delivering efficient costs, but the risks and costs would be higher for customers connected to the original NSP. This suggests that the AEMC's proposed model be revisited.

The MEU prefers option 1 (maintain the existing bilateral negotiation framework but permit NSPs to declare "open seasons" for connection in APRs).

Again, the AEMC dismisses options with the view "we consider that the remaining models will either not deliver the desired outcomes, or will achieve them in a less efficient manner".

2.1. Questions Raised by AEMC

2a Will the recommended model adequately address the deficiencies in the existing framework?

Yes, but at the expense of existing consumers wearing the risks and associated costs for surplus capacity.

2b Does the recommended assessment process appropriately balance customer risk with potential customer benefits?

No, consumers are exposed to a range of risks and costs, viz:

- Regulatory risks associated with AEMO/AER assessments
- Absence of principles, let alone details concerning the allocation of costs
- Failure of new generators to link up to new connections, thereby raising unit costs
- Competition from non-regulated NEGS.

2c Is there merit in allowing rival service providers to deliver network extensions for remote generation?

Yes, except that consumers are again expected to assume the risks and associated costs under the AEMC preferred model.

3. Efficient Utilisation and Provision of the Network

What MEU members have seen within the electricity networks of recent times is that the load factor on the networks of usage by end users has been falling, implying that demands for power is increasing although the consumption of energy is raising at a lower rate, causing a need for greater capacity but which is used for lesser time. One of the major contributors to this is the greater incidence of refrigerative air conditioning, especially in the residential sector.

The outworkings of the CPRS and xRET will similarly cause a reduction in load factor as a result of the greater incidence of intermittent generation. Increases in intermittent generation requires large increases in capacity (for example wind energy has a load factor of some 30-35%, implying the capacity of the networks needs to be increased to accommodate the high levels for short periods of generation from intermittent generation but which lies idle for extended periods.

Intermittent generation requires dispatchable backup generation, and this back up generation will be located remotely to the intermittent generation, requiring augmentation of other elements of the networks to accommodate the added generation which in turn operates at a low load factor.

As much of the backup generation will be gas fired, this in turn increases the demand on the gas networks to provide relatively short term peaking capacity of gas supplies needed to provide back up capacity to intermittent renewable generation.

The current arrangements and pricing approaches used by networks (especially the pricing policies of distribution networks) do not provide strong price signals to end users causing much of the need for short term peak demands. Similarly, there are very weak price signals for generation to locate where there is capacity in the existing networks to accommodate the new generation capacity being installed.

Strong price signals are need to ensure the most economically efficient usage of the networks is achieved. In this regard, the MEU has been a strong supporter of the view that generators should carry some of the costs for providing the electricity transmission networks. Such an approach recognises the basic approach in most other businesses where the supplier has the responsibility to deliver its product to market. Where this does not occur, the purchaser factors in the delivery costs of different suppliers to reflect the costs of delivery. In the electricity market, generators do not currently see the cost impact of their locational decisions other than the costs for losses[1] and end users pay the costs for the locational decision of generators.

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[1] Expecting losses to provide generation locational signals is made more complex by the decisions to have large regions. Losses are calculated to the regional reference node and where a generator is remote from the regional reference node, it pays for losses calculated to the node. This is despite that fact that the generator might have located new to a nearby load point and has realistically located in an economically sensible place.

Inappropriate generation location drives two major outcomes:

- Because the costs for augmenting the networks falls on consumers, generators do not see the cost impacts of their locational decisions, but these decision do increase costs to consumers through network charges
- Generator location can lead to increases in congestion which forces the out-of-merit dispatch of higher priced generation, which increases costs for the supply of power in the spot market.

Because of these observations the MEU agrees with the AEMC's assessment, viz:

"We consider that stronger price signals can influence behaviour and deliver more efficient location and retirement decisions. At the margin, renewable plant may be flexible in its location decisions, given the right pricing signals. Gas plants are also more flexible with their location decisions, trading off transmission connection and gas pipeline costs. A signal that informs timely retirement decisions frees up scarce network capability to more efficient plant. The absence of an efficient price signal may also lead to generators locating in areas where they bypass existing generators in order to access the regional reference price (RRP). This will lead to inefficient costs and increases the risk of being constrained off for existing generators." (AEMC, page 28)

and that

"The most effective way to address the increased congestion arising following the introduction of the CPRS and expanded RET is through providing cost reflective price signals to generation. This will ensure that generators correctly factor in the total costs caused by their decisions, thereby promoting more efficient behaviour and more efficient utilisation of the network." (AEMC, page 29)

Stronger and correctly applied price signals for both generation and end users should lead to more economically efficient use of the networks and making generators carry costs resulting from their locational decisions should provide an incentive to locate in a manner which is also more efficient.

3.1 <u>Questions Raised:</u>

3a	Do you agree that we have accurately identified which elements of the existing framework are considered inadequate and therefore require change?

The AEMC has carried out good analysis of the issue here and its assessment covers most of the issues. We would, however, add that the AEMC should also look at the current approach that the number of regions in the NEM is too small and as a result the pricing approach in the regions (essentially based on the five states) is also inefficient. Increasing the numbers of regions could lead to more economically efficient outcomes and send stronger pricing signals.

Retention of the current five regions will act as a disincentive to more sensible locational decisions for generators. Further, their retention increases the lack of transparency of intra-regional congestion. Increasing the regions in the NEM will make the impacts of congestion and out-of-merit dispatch more transparent.

3b Would the G-TUOS charging option design improve pricing signals to promote efficient location and retirement decisions in the most efficient way? Are there any design variations that may improve the signals?

The MEU has long been a supporter of generators having to carry some or all of the costs for the transmission network as a way to encourage sensible locational decisions by generators. The G-TUoS approach is, therefore, supported.

Once this approach is implemented, decisions by generators will be made on a total effect basis. Such an approach would allow generators to augment networks to reduce congestion caused by their locational decisions.

We recognise that under the current arrangements there is an incentive on new generation either to not locate in a sensible location due to their concern of being constrained off due to congestion, and requires a new generator to pay for the deep connection costs associated with its dispatch. Equally, existing generators fear new generation will cause congestion and so limit their ability to be dispatched.

What is required in the G-TUoS approach is for all generators that will benefit from augmentation to reduce congestion will be able to readily join together so that all will pay for, and benefit from, the reduced congestion.

The AEMC posits a concept that the total cost for G-TUoS would be zero ie that some generators would pay and some would get a benefit. The argument for this approach is that it retains the current balance of end users continuing to pay for the net cost of the transmission network. Such an approach would be administratively complex and require qualitative assessments (eg what is the extent of each zone and is this the optimum arrangement to capture all generation in an equitable manner?). It raises the difficulty of overcoming the deep connection costs incurred by adding new generation and who will pay for this.

A more equitable approach would be to have G-TUoS be a proportion of the total cost of TUoS reflecting the total costs incurred in an administrative region back to a number of notional connection points to the shared network. Such an approach would be consistent with the concepts propounded by the AEMC for grouping remote generation for a common connection to the shared network as discussed in section 2 (connecting remote generation).

The MEU considers that consistency and neutrality are essential elements for developing equity and providing sensible price signals. The concept of the G-TUoS having a total value of zero provides a clear benefit to incumbent generators and disadvantages new entrant generators. Under the proposal for connecting new remote generation ultimately the new remote generators will be paying the full value for the new connection assets up to the point of connection to the shared assets. Under the G-TUoS approach with a zero net cost, incumbent generators will be provided with elements of the shared assets which provide the same service as the NERG does for the new remote generators but at no cost. The zero cost option for G-TUoS is not competitively neutral for new entrants.

Just as NERG incurs a cost to new entrants, G-TUoS should have a cost which reflects the similar service provided to a cluster of incumbent generators, and this cost should be transparent, identifiable and reflect the costs of providing the network for the cluster of incumbent and new generators.

3c Given that G-TUOS is a preferred option, what additional value would a congestion pricing mechanism add? If such a mechanism is required, what design variations should be considered to improve signals to manage short term intra-regional congestion in the most efficient way?

Intra-regional congestion would be reduced if there were more NEM regions, reflecting the fact that what is currently intra-regional congestion, would become inter-regional congestion and therefore become transparent. This increased transparency would provide signals to reduce the congestion identified.

Because G-TUoS as proposed will only impact decisions on new generation, the AEMC sees that there are problems in the short term in relation to the benefits it will deliver. This is because the AEMC is still struggling with trying to allow incumbent generators "free access" to the shared network while trying to make new generators pay for their decisions. This determination to maintain a lack of neutrality between new and incumbent generators is creating unnecessary complexity. Treating all generation on the same basis as the proposed NERG approach provides neutrality and overcomes many of the complexities and issues raised by the AEMC.

The MEU considers that charging G-TUoS to make it effectively on the same basis as NERG would provide significant relief to the incidence of intra-regional congestion, especially if the NERG and G-TUoS included for the necessary deep connection costs beyond the connection point between G-TUoS and the shared network.

It has been previously raised as an issue that incumbent generators should not be exposed to any TUoS costs as this would add a fixed charge to their cost structure, and therefore make it difficult to price their dispatch into the market. The AEMC proposals require new generators to carry such a cost, so therefore this should not be a problem for incumbent generators.

The second reason for not imposing a TUoS cost on incumbent generators is that a number of the generators were purchased on the basis they had "free access" to the transmission network, yet new generators have to pay for this access. To continue to maintain this differentiation between new and incumbent merely continues the preference incumbent generation has, and has been a disincentive on new generation. It is time that such benefits of incumbency are excised. If the Federal government can decide that incumbent generators must pay for their carbon emissions despite that decisions to purchase a power station were made prior to CPRS, then the argument that the network Rules cannot be changed to reflect neutrality also should be seen in the same light.

The AEMC has an opportunity to recommend a change to provide competitive neutrality between new generation entrants and incumbent generation, and should use the opportunity to achieve this outcome. The NEL requires competitive neutrality for the treatment of technologies and participants.

4. Inter-regional Transmission Charging

Equity would imply that an importing region should provide a contribution for the assets used in another region to enable the importation of power from the exporting region. End users in the exporting region should not be carrying the cost for assets which do not provide a benefit to them, and if these assets are used to provide power to another region than the cost for providing those assets should be carried by the beneficiaries in the importing region. This is the basis for the AEMC decision to recommend a change to current practice

The reason for inter-regional trade is the importing region either has insufficient generation for its own needs (such as NSW) or that the generation in the importing region is more expensive than in the adjacent exporting region (such as between SA and Victoria).

Under the current Rules, power in an exporting region has to be priced below that of the importing region if power is to flow. This differential between the prices between regions could be minor or significant. This raises two significant issues:

Firstly, the implication of the “load export charge” as propounded by the AEMC is that there will be a set charge for the amount of exported power which will be levied on the importing region. The reason there will be a set charge is that TUoS charges reflect the cost of providing the service which is driven by the assets used for the service.

This set charge could be priced on a demand and/or consumption basis. A price set on a demand basis would reflect a need for the assets (ie even if the assets are not used, they are always available to provide the service) and if set on a consumption basis they would reflect the amount of power exchanged between the regions. Thus the first issue that needs to be resolved is whether the charge should reflect the availability of the assets to provide the export service (i.e on a MW basis) or whether it should reflect the volume of the trade between the two regions.

The explanation in appendix G does not determine whether the charge should be reflective of demand or consumption, yet such a distinction is an essential element in order for the development of an equitable load export charge. The AEMC has determined previously that a beneficiary of a service should be required to pay for the service provided even if the service is used occasionally – the mere requirement to provide the service incurs costs to provide it. On this basis the load export charge should be costed on a demand basis only.

An exporting region TNSP might provide the assets capable of meeting a large export demand but the importing region only provides the assets to receive a lesser demand. Therefore it is necessary to determine the basis of setting the export charge based on demand.

The implication of the text in chapter 4 implies that it would be expected that the charge would be the net impact of inflows and outflows (second dot point on page 42), and this would reflect a charge based on net consumption. This then leads to the second concern with the proposal.

Secondly, if the export charge is based on consumption (ie a price per MWh) for providing the export service then there is a need to match the export charge to the dispatch price for generation, because if the export charge is greater than the difference between the exporting regional price for power and the importing regional price for power, then consumers will not be paying the economically efficient price for power.

For example, if the dispatch price for power in the importing region is $50/MWh and the dispatch price for power in the exporting region is $45/MWh power would flow between the two regions, from the exporting region to the importing region. Power at the lower price would continue to flow up to the point at which congestion occurs and there is a separation of price between the regions.

If the export charge is $4/MWh then the price for power in the importing region is $49/MWh and to use this imported power is efficient compared to the indigenous generator price of $50/MWh. If, however, the export charge is $6/MWh, then the imported power would still flow (because the generator dispatch price differential would still apply, but the effective price for power in the importing region would be $51/MWh, which is not efficient compared to the indigenous generator price of $50/MWh.

To accommodate this anomaly AEMO would have to add the set charge for export power into its dispatch engine to ensure that the most efficient price was used for dispatch. This then raises another issue. If the generators in the importing region know the export charge from the adjacent region, then this allows them to increase their bids by just less than the export charge and, by doing so, accrue an economic rent.

The original concept behind the development of the NEM was that there would be a national transmission grid that would allow the free flow of power between regions, based on the most efficient generators being dispatched first regardless of the region in which they are located. The constraints between regions prevent this from occurring and the Rules as written do not incentivise a TNSP to build assets to increase the capacity of inter-region connections. Allowing the recovery of costs for providing inter-regional flow provides an incentive to augment inter-regional connections.

Whist the MEU does see there is merit in there being a charge payable to an exporting region by an importing region to reflect the value of assets provided I an exporting region to allow the transfer of power to another region, the proposal developed by the AEMC and outlined in the Report, needs much more analysis and development to ensure that there is equity in the actual basis for charging. The MEU sees that attempting to develop a mechanism which operates notionally in real time will provide some unintended distortions in the market.

The MEU considers that to overcome some of the disadvantages in the AEMC model as proposed perhaps the charging between regions could be carried out on a similar basis to the allocation of the inter-regional settlements surplus which is allocated the year after it is recovered. An ex post annual transfer of net revenue between regions for providing assets allowing recovery of an exporting region's costs provides more certainty and no unintended consequences. Such an allocation would reflect the actual transfers of energy and the degree of demand capability.

4.1. <u>Questions Raised</u>

Questions
4a Is the proposed design for the load export charge appropriate as an effective mechanism to address the identified problems?

The MEU agrees that there needs to be an incentive on TNSPs to provide stronger inter-regional connection. This feature is currently absent in the current Rules.

The AEMC proposed design fails to address a number of basic issues with regard to equity and neutrality, and these are noted above. The MEU considers that an ex post adjustment should be made on an annual basis in arrears to prevent unintended consequences that will arise in the AEMC approach

4b. Is our suggested commencement date of 1 July 2011 achievable?

Whilst the date might be achievable the MEU is concerned that the implementation of what might potentially make significant transmission pricing changes, needs to be assessed in terms of the cost impact on end users at a time when most end users are under significant financial stress.

5. Regulated Retail Prices

The MEU agrees with the AEMC's assessment that:

> "The desired market outcome is for the energy market frameworks to promote and support healthy competitive retail markets that deliver efficient prices and services to energy customers.
>
> For competition to be effective retailers must be able to charge cost reflective prices to end use customers. If regulated retail prices are kept too low, development of competition will be hampered. Conversely, if regulated prices are set too high and competition is not effective, customers are likely to pay too much for energy." (AEMC, page 50)

However, the AEMC's assessment is premised on the assumption that there is a competitive wholesale market based on:

- Robust competition between competing suppliers
- Absence of dominance by any single generator.

For example, as the AEMC may be aware, the South Australian electricity market is characterised by:

- The presence of a vertically-integrated gentailer, with dominance in generation and retail
- The lack of liquidity in the form of hedging contracts
- The departure of second tier retailers
- The ability of the dominant generator to set the wholesale price when demand reached 2500 MW, i.e. 80% of Maximum demand, and without the need to rebid[2]
- Very high barriers to new entrants in generation and retail.

Indeed, the non-competitive market structure in the South Australian market was recognised by the South Australian Government, when it declined to implement the AEMC's recommendation for the removal of the retail electricity price cap.

The South Australian market is not the only region where dominant generators are able to exercise market power. The following commentary and table shows analysis undertaken by the MEU on behalf of some of its members in early 2008, on the potential for generators to exercise market power in their regions.

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[2] The AER's recent report (page 7 Investigation Report on AGL's compliance with the good faith rebidding provision of the National Electricity Rules on 19 February 2008, May 2009) stated that on 48 out of 51 occasions when prices exceeded $300/MWh, AGL/TIPS did not even need to rebid.

"The demand points at which dominant generators in the NEM are likely able to spike prices and engineer large wealth transfers largely from consumers to generators in most NEM regions are considerably below peak demand levels. For each region the peak demand levels are shown, along with the % of peak demand where the largest generator has the ability to set spot prices:

Region	**Peak demand MW**	**% peak demand when largest generator has market power to set spot prices**
South Australia	3000	83%
New South Wales	14000	86%
Queensland	8500	>113%
Victoria	9700	>101%
Tasmania	1750	35%

The NEM has become increasingly concentrated, especially with the structural aggregation of generators with retailers, to form a new business structure by the creation of "gentailers"[3]."

This analysis has been effectively supported by analysis by AER where it has determined that AGL/TIPS can exercise market power when regional demand reaches 2500 MW, some 80% of the highest peak demand of 3100 MW recorded in the SA region.

If such market power exists in the wholesale market and generators have been seen to exercise such market power then this indicates that the AEMC assumption that wholesale markets are able to

"…support healthy competitive retail markets that deliver efficient prices and services to energy customers" (AEMC, page 50)

is erroneous. The facts and the direct experience of large consumers do not match the assertion.

Be that as it may, we do agree that the costs of the CPRS need to be reflected in retail energy prices, notwithstanding the AEMC's belief that wholesale markets are competitive.

We note the AEMC assesses:

"The CPRS will significantly increase the wholesale electricity purchase costs and volatility incurred by retailers. The increases in costs will be hard to forecast and initially difficult for retailers to

[3] A gentailer could be likened to the outcomes that the much criticized New South Wales Electricity Tariff Equalization Fund scheme achieves.

> manage with financial hedging. These factors will make it very difficult for pricing regulators to accurately forecast and allow for costs in retail prices." AEMC, page 50, 51)

and

> "The costs of generating electricity will increase because generators will have to acquire and surrender CPRS permits for their emissions. Whilst the emissions per unit of electricity vary depending on the fuel used, on average approximately one tonne of carbon dioxide is released for each megawatt of electricity generated. Retailers will face increased financial risk following the introduction of the CPRS. Analysis undertaken for the Commission confirmed that the extent to which the CPRS drives up electricity wholesale purchase costs will be uncertain and will be hard to forecast. A number of factors will influence this. One is the proposed unlimited importation of international permits. The price of these may drive local permit prices and in turn will be driven by international demand, policy and regulatory settings and exchange rate fluctuations.
>
> Another uncertainty in forecasting energy costs will be the extent to which carbon costs imposed on generators flow through to wholesale energy purchase costs. In the electricity market the bid of the marginal or last generator dispatched to meet demand sets the spot price for a period. The emissions intensity of the predominant marginal generator type will influence overall carbon cost flow through. There have been a wide range of model outcomes for this flow through (ranging from 40 per cent to over 100 per cent), but this flow through may vary over time.
>
> Analysis indicates that, depending on the level of carbon price and the extent of flow through to wholesale costs, the increase in total retailer costs could range from 10 per cent to 30 per cent."(AEMC, page 51).

All the above significantly increase risks and the associated costs of both the direct impact and the costs to manage the increase risks will impact on all customers, whether contracted or protected by a retail price cap.

5.1 Questions Raised

5a Do you agree that wholesale energy costs will be less certain, less able to be hedged and harder to forecast following the introduction of

the CPRS?

Yes, but the MEU considers that the current volatility is too great and should be reduced. With this in mind, the MEU queries whether the impact of the CPRS is sufficiently significant to warrant a change. We are not persuaded that the risks faced by retailers will be as severe as implied by AEMC when assessed in comparison to the current risks faced.

The AEMC observes that pricing for emission certificates in the prices offered by generators are likely to vary dependent on which marginal generator is likely to be dispatched. The AEMC observes that a high emission brown coal generator when it is the marginal generator, will price the permit at its full value, but a lower emission generator when it is the marginal generator will factor in a lower emission cost. The AEMC goes on to state that its analysis shows that the cost variation for emissions could vary between 10% and 30%.

The MEU concurs that there is likely to be such a variation and this will impact on the market price for each price period. But the market already shows even larger price movements under the current structure, with the potential for the market price to vary between -$1000/MWh and +$10,000/MWh. Volatility in the current market is very high and the AEMC (and others such as ERIG) have observed that such volatility is essential for providing adequate market signals.

The MEU has raised the issue of excessive volatility with the AEMC in prior communications but the AEMC has decided that the volatility is needed. If that is the case, the MEU is at a loss to see why the forecast volatility resulting from CPRS should be considered as of greater import than what is seen now. Following the AEMC assessment of the current market, price signals are required and volatility is an essential element of these price signals. The AEMC appears to base its decisions on conflicting arguments depending on the issue being examined.

Disappointingly, the AEMC's analysis does not include assessments of the likely concentration of the energy market and the strong incentives for exercise of market power by dominant generators, price spiking and revenue recovery by expiring generators, and the total effects of these (on top of the CPRS and RET) and likely electricity prices for all consumers.

The AEMC's assumption that NEM is competitive is erroneous. However, its assumption allows the AEMC to conclude that the current "energy market frameworks are robust" and highlights the inadequacy of the analytical work undertaken by the AEMC in developing its recommendations.

On balance, if the AEMC considers that the current level of volatility and risk is acceptable, then there is little reason to change the market to accommodate the added volatility and risk CPRS will bring. If the AEMC considers that the CPRS brings too much volatility and risk, then it is incumbent on it to address the current level of volatility and risk.

5b If jurisdictions and/or pricing regulators incorporate additional flexibility in pricing instruments, as set out in the recommended principles, does this sufficiently decrease the risks to retail competition and of retailer failure?

Yes, but to a limited extent as the competitive market structure at the wholesale and retail levels is not robust. The MEU has identified that competition at the wholesale level is currently a major issue in developing the basic level of retail competition in the NEM. Building onto a flawed market structure only adds to the risks faced by consumers and retailers.

Whilst the MEU considers the principles behind the recommended changes for retail pricing have merit, it is concerned whether too much devolvement of responsibility to retailers is likely to be beneficial to consumers. MEU members have extensive direct experience with retailers through their regular need to negotiate new contracts. Where there is a vestige of market power that a retailer might have through its ownership of key assets (eg gas production and generation) we have found that competition is significantly reduced and negotiation becomes very difficult. Where negotiation is one sided, outcomes are not competitive, and yet viable competition is what is assumed to be available in the electricity and gas markets.

5c Are existing regulatory approaches adequate to assess the cost to retailers of the expanded RET?

No.

The current market already has a limited requirement for providing renewable energy as a proportion of the energy usage by all consumers. Retailers already have identified methods where they can achieve competition in the sourcing of the RECs needed to demonstrate compliance with the MRET. Tenders received from retailers for the supply of energy already include varying prices between retailers for the provision of RECs, requiring consumers to include the cost of RECs (and VRECs and NGACs) in the overall price offered by retailers for delivered energy. If retailers can offer RECs in a competitive manner now, there is little reason to assume that in the future, providing the legislation is clear on annual requirements for renewable target, that retailers will not be able to include competitive offers under the xRET requirements.

5.2 A General Comment

Consistently throughout this section on regulated prices, the AEMC refers to the discussions held with retailers and the requirements of retailers to operate in the markets. What is concerning is that the AEMC has direct access to seek the advice of large consumers who do regularly negotiate with retailers and have first hand experience of what retailers actually can and do achieve in relation to the risks they face. Despite this the AEMC must have decided that these experiences could have no bearing on its analyses, and therefore has elected to take the advices of the retailers without any attempt to verify these from actual experience.

This seems to highlight an apparent view within AEMC that it needs only to converse with supply side entities to identify the needs of the markets.

The MEU considers this to be extremely short sighted and as a result provides AEMC with a blinkered view of the markets and their needs.

Overall, the AEMC's review displays a concern for retailers, but not for consumers. This is disappointing, given that the review concludes that the NEM will be more volatile, riskier and faces significant costs.

The best way to ensure efficient costs is to develop market structures (or change the existing Rules) which maximise competitive outcomes. Yet this issue is totally ignored by the AEMC review. There are always assertions about proposed outcomes being efficient, but the evidence (especially including empirical evidence) is not provided.

6. Generation Capacity in the Short Term

The MEU agrees that in some regions there are

> "…relatively tight capacity margins currently – and therefore a heightened exposure to reserve shortfalls, either consequent to the transition in generation capacity resulting from CPRS and expanded RET or otherwise". (AEMC, page 60).

The MEU agrees with the AEMC's draft recommendation that the reserve shortfall risk be addressed through a combination of:

- "facilitating more accurate reporting of demand side capability; and
- utilising the potential for distribution connection generation to help alleviate capacity shortfalls." (AEMC, page 61)

We also agree with the AEMC that:

> "…there is a technical risk to the availability of existing plant caused by the introduction of the CPRS and the expanded RET. The carbon prices resulting under the CPRS and expanded RET could reduce future generation profitability and, hence, impair the value of most carbon-intensive coal-fired generators. A decision to either maintain or retire plant will be driven by expectations of future returns." (AEMC, page 63)

and

> "…we remain of the view that the current frameworks would not adequately address the risk of capacity shortfalls in the short term following the introduction of the climate change policies. Given the potential for significant disruption and the costs incurred should the framework fail, there is a need to amend the existing mechanisms to strengthen the resilience of the arrangements to respond to such risks." (AEMC, page 63)

6.1 Reserve Contracting

The MEU recognises that the energy-only market approach has resulted in a number of undesirable outcomes, particularly that it probably has only encouraged investment in peaking generation. The MEU also is of the view that this investment in peaking generation is more a result of retailers needing to provide physical hedges against the very high market price cap (VoLL) than as a driver for investment for new generation per se.

Most world renowned energy market economists (eg Tirole and Jaskow) have consistently observed that the energy-only market causes the need for generators to exercise market power as in theory the energy-only market price offers should reflect the short run marginal cost, whereas generators need to recover long run marginal costs to remain viable. Because of the concerns that there is insufficient investment in base and mid merit generation occurring in the NEM (compared to the significant investment in generation in capacity markets) the MEU is of the view that the energy-only market cannot provide adequate generation investment.

The MEU points to the continuing need for Reserve Trader powers being retained in the NEM as supporting its view that the energy-only market is unable to provide sufficient reserve capacity to maintain the levels of reliability expected in the NEM. That such powers are still needed and that with the introduction of CPRS and xRET the AEMC sees there is a need to augment the Reserve Trader powers (eg as it observes id required of the recently implemented RET approach) or by other more intrusive approaches such as standing reserve, and prolonged targeted reserve.

The need for such distortions and the views of eminent economists are all indicators that the current energy-only market structure might not be the best solution for managing the current market, let alone the impact of CPRS and xRET. Rather than address this far more fundamental issue, the AEMC has taken the easy way out and decided that the maintenance of intervention in the guise of the various Reserve Trader approaches is a preferable supply side outcome.

Of the different approaches to the Reserve Trader intervention, the MEU considers that a modest supply side option combined with a viable demand side approach is likely to result in the lowest overall cost to consumers. Effectively, it would appear that the AEMC supports the implementation of the RERT as the basis for its recommendation as RERT is currently being modified by the Reliability Panel.

On this basis the MEU considers that least distortionary approach to managing a potential supply side shortage of generation in an energy-only market is the AEMC's <u>first</u> recommendation for a short notice reserve contracting mechanism. This mechanism is being currently addressed by the AEMC Reliability Panel and MEU comments on the mechanism will be provided in its submission to the Reliability Panel.

The MEU does not agree with the AEMC's assessment (and apparent dismissal) of the standing reserve and the prolonged targeted reserve options. Both of these approaches reflect some of the features of a capacity market but without the widespread benefits that a capacity market would provide the NEM. The AEMC points out that that implementation of such capacity mechanism approaches as proposed is that they will distort the energy-only market concept. The MEU would comment that implementation of a capacity market is likely to solve both the problem of CPRS and xRET as well as solve the fundamental problem the current market faces of insufficient investment in generation.

The AEMC points out that the capacity market approaches, as proposed, "may not represent value for money" but then fails to carry out any analysis to support this contention.

The AEMC goes on to state that the approaches might lead to capacity to be withdrawn from the energy-only market as the revenue stream achieved by doing so, might be more certain. Yet consumers have seen exactly this same approach used in the energy-only market where generators bid and rebid amounts of energy into higher price bands (effectively withdrawing capacity) in order to effect a larger revenue stream. If there was a payment for capacity, then the dispatch of a generator for a fair and reasonable energy price is more in control of the market, rather than allowing a generator to withdraw capacity in order to increase its revenue.

The AEMC adds that having a capacity market approach puts more responsibility onto regulators whereas a market based response is more controlled by the participants who carry the risk. The MEU would point out that ultimately it is consumers that carry the risk of both the cost of supply and the reliability (failure) of supply.

The market participants do not (as averred by the AEMC) carry the price risk or the reliability risk, as the price risk is passed onto consumers through market charges and retailers do not incur costs for non-supply if the market does not deliver power to consumers. MEU members have yet to receive an offer for power supply where a retailer carries exposure for failure to deliver supply to an end user. If the AEMC had bothered to ask consumers what really happens in negotiations between consumers and the supply side entities, then it would not have made such an elementary assumption as a reason to exclude an option for evaluation. One-sided analysis lacks objectivity.

6.2 Better Reporting

The MEU agrees with the AEMC's second proposed recommendation for more accurate reporting of demand side capability. There are, however, implementation issues that need to be addressed. The experience of many large energy customers is that often, retailers do not call on the available demand side response, notwithstanding the existence of demand side contracts. In addition, some retailers do require substantial sharing of the demand side revenues that are triggered, thereby reducing the value of demand side participation. These facts were provided by MEU representatives in the AEMC's demand side participation working group.

Concerns with commercial confidentiality can be addressed by aggregation of information so that no specific consumer information is released into the public arena. This issue has been addressed in the development of the Contingency Gas element in the short term gas trading market.

However, one of the major issues associated with getting better data on demand side responsiveness lies with the retailers through which most consumers operate. Retailers see that implementing DSP can be a detriment to their operations and unless they have significant exposure themselves to the spot market, they appear loath to encourage DSP.

The MEU members are prepared to share their experiences of DSP and their relationships with retailer with the AEMC.

6.3 Embedded Generation

The MEU notes the AEMC's third draft recommendation concerning more effective use of existing but under-utilised embedded generation. Many of these assets are owned by consumers seeking to have protection against loss of power supply. Discussions between the AEMC and those consumers owning such assets would have revealed there are a number of reasons why this source of support has been extremely modest to date. Such reasons range from environmental and permit issues (EPAs limit the amount of use these generators are permitted due to exhaust and noise aspects, local councils restrict their use, etc) through the constraints applied by the local distribution networks (and their resistance to allow access and network pricing strategies) to the needs of NEMMCo (now AEMO) for metering and control. The cost structures associated with such generation also needs to be addressed through the relationship between the consumer and its retailer.

In principle, the MEU supports the concept of there being better use made of assets already connected to the electricity system such as embedded generation but we point out that significant work is required (especially in the NEM) to allow such an option to be implemented.

6.4 Load Shedding Management

The MEU supports the AEMC recommending the introduction of an arrangement to facilitate more efficient prioritisation of load shedding via some formalized load shedding management (LSM). The concept of LSM, which involves contracting with large users of electricity to provide remunerated firm load reduction capacity, as an alternative to involuntary load shedding through the current regional load shedding schedule, is to be a major feature of the gas Short Term Trading Market.

The principle of Contingency Gas (CG) in the STTM is that large consumers of gas will be able to offer gas back to the market at a price which is set in a price stack of offers, with the lowest price being called first. The maximum price for CG is VoLL. This feature is an attempt to balance the practice of large gas consumers always being load shed in the event of a gas shortage.

There are some large users of electricity that effectively load shed when prices are high (such as those operating in the spot market) and this load shedding does provide some relief in a near constrained market. Those consumers operating in the spot market see load shedding as a mechanism to reduce the overall costs of power in the NEM. Many companies would provide voluntary load shedding (as an alternative to being involuntarily load shed) provided they can recover the costs for shutting down some or all of their operations. There are commercial businesses actively in the market for aggregating such offers but the current NEM rules prevent this occurring. In contrast, the capacity market for electricity in WA, does allow such voluntary load shedding and as a result there are many large electricity users prepared to enter into arrangements for voluntary load shedding when there are potential shortages of power.

One key aspect that the AEMC needs to appreciate is that a consumer might not be driven to enter the market to load shed purely on a market price basis, but would be more driven by the alternative that curtailment is the likely option – in this regard it must be seen that consumers need electricity in order to conduct their business and would prefer to have electricity for productive purposes than to trade their capacity in the NEM.

The AEMC observes that LSM might be at a price higher than VoLL and this is possible. However, a number of large electricity users have indicated that as an alternative to load shedding any reimbursement is better than receiving none (as they do now) and that they might consider voluntary curtailment at a price less than VoLL. In this regard, during the development of the CG for the STTM, calculated costs for selling gas entitlements back into the market were in many cases less than the VoLL set at $400/GJ, which on a comparative basis is less than half the amount set for VoLL in the NEM.

We have examined the proposal for LSM incorporated in appendix H and would observe that a number of the features included in the outlined approach would not encourage many large electricity users to offer for voluntary load shedding. We would encourage the AEMC to discuss with potential providers of voluntary load shedding prior to fixing any detailed approach to implement LSM.

The MEU considers that:

- LSM is a more economically and socially desirable outcome than involuntary load shedding
- Large users of energy have sophisticated risk management programs, which will readily facilitate LSM by providing a significant pool of capacity
- Large users of energy are introducing on-site generation in response to Climate Change policies and will have additional capacity to participate in LSM

6.5 <u>Questions Raised</u>

> 6a Is it the case that there can be commercial advantages in market participants not disclosing information about Demand Side Participation (DSP)? If so, what factors should we take into account in drawing out accurate information about the levels and firmness of DSP that market participants have contracted?

End users are prepared to provide such information as long as the information is aggregated so that information of a specific consumer cannot be identified. The MEU is aware that some retailers are not as keen for such information to be provided and if there is a preparedness for a consumer to offer DSP, some retailers seek to retain much of the commercial benefit the DSP might deliver from the market.

Therefore the market structure acts to prevent DSP rather than encourage it. In the gas STTM, because large consumers are listed at the top of the curtailment tables, it is possible for those operating within a retail arrangement for gas supply, to make known their preparedness to offer CG into the market and at what price. This has the impact of making retailers more willing to allow DSP to be used within the STTM.

To allow AEMO access to such information could overcome the observed reticence of some retailers to allow greater amounts of DSP to be accessed by the market.

6b Active load shedding management could mitigate the need for involuntary Load shedding. Should we recommend this mechanism as part of our final advice to the MCE?

Yes. The MEU believes that the NEM structure needs to be modified to allow this feature to be incorporated into the NEM Rules just as it is in the WEM.

7. Investment in Capacity to Meet Reliability Standards

The MEU strongly **disagrees** with the AEMC's views as stated in the chapter summary:

> "This Chapter discusses our draft findings on the framework for long term reliability in the NEM. We have found that the existing framework provides effective signals to promote efficient levels of investment in both transmission capacity, generation capacity and demand response. It can, therefore, be expected to continue to operate in the long term interests of consumers, if those signals are appropriately maintained. This is likely to involve significant increases in the spot market price cap over time, in particular to ensure that the necessary peaking plant to complement intermittent wind-powered generation is economically viable.
>
> We recognise a number of risks inherent in the current framework, including issues relating to the practical operation of the contract market, and note that some of these risks might be exacerbated by an increase in the range of possible price outcomes in the spot market. However, we are not persuaded that these risks are substantially altered by the implementation of the CPRS and expanded RET or that fundamental change to the existing frameworks are needed in order to manage them" (AEMC, page 71)

The MEU considers that, contrary to AEMC assertions, the existing framework does not provide effective signals to promote efficient levels of investment in transmission capacity and generation capacity, or in demand response:

The MEU observes that by far the greatest amount of base and mid merit generation built since the NEM commenced has been driven by government concerns about a shortage of generation, or built with active government support. There has been significant peaking generation built but this has been built by retailers driven more by the need for a physical hedge than by the signals in the market. Further, there are regions where market signals should have resulted in new base and mid merit generation but there has been no such investment.

What consumer demand response there is, (essentially by large consumers taking spot market risk) has been the result of retail price offers being significantly higher than the spot market average price or because of a lack of retail competition driving competitive outcomes.

Large users require a mix of lower priced base and intermediate generation. The short term nature of the additional gas peaking capacity built has meant that large users have been unable to obtain long-term electricity contracts. Contract prices have escalated as a result, fuelled by increased risks associated with a highly volatile NEM.

Demand side responses have been minimal in the NEM. The price cap approach to network pricing reviews discourages demand side initiatives.

There is a major error in the AEMC's assessment. The AEMC has commented that it is not persuaded the introduction of CPRS and xRET will increase the market risks inherent in the current framework, yet the AEMC itself (in section 5 see point 5.1 above) sees that the risks on retailers is sufficient to warrant the removal of price caps. This seems to be a contradiction in the AEMC arguments.

Network assumption

We have reviewed the excerpts in the AEMC draft report[4] referring to the issue of demand side participation in the NEM, and the assumptions made by AEMC. We consider that the reasons given by it in appendix C2 to dismiss the TEC views propounded regarding the NEM bias to incentivizing augmentation over DSP, are erroneous.

There is a fatal flaw in the AEMC argument in relation to networks incentives, and when this is assessed, it destroys the argument provided by the AEMC.

The assumption made by the AEMC is that any increase in demand will be accommodated at the same cost per unit to the customer seeking an increase in demand (i.e that an NSP has to trade off between the costs of augmentation and the increased revenue from the increased demand).

In the case where there is no need to augment the network (and therefore no need to seek DSP) this will occur. The only cost that the customer would incur would be the costs associated with accommodating the increased supply to it (e.g for new transformers and switchgear at the point of connection). Under the Rules, connection costs are to be negotiated between the customer and the NSP.

In practice what occurs (and allowed for in the Rules) is that where the network needs to be expanded to accommodate the increase in demand, the NSP advises the customer that either

- The increased demand cannot be provided and another solution has to be found, or

[4] Draft Report; Demand-Side Participation in the National Electricity Market, 29 April 2009

- The connection cost will include for the augmentation of the network.

In either case the supposed trade off the NSP sees (of trading the increased costs to augment the network off against the added revenue generated from the increase in demand) never occurs.

The issue can also go further. In many cases the NSP builds into its capex program the expectation that the increase in demand will occur over the next regulatory period, and therefore the capex program actually allows the NSP to build the augmentation to suit the expected needs. This then raises the issue – why would an NSP prefer a DSP solution where the NSP gets reimbursement of the direct costs only (as the DSP program gets reimbursed at cost as it is part of the allowed opex) without any profit when if it spends on capital it gets a profit. And the higher the WACC, the higher the profit!

Our view is that the AEMC conclusion that market forces will drive an NSP to seek and implement DSP is based on an erroneous assumption as it assumes an NSP will seek lower costs for consumers over an ability to increase profitability an higher rewards for its shareholders.

Risk management products

The AEMC makes much of the ability of the market participants to protect themselves from the market volatility by use of hedging products such as swaps and caps. This is agreed, but they will only work if there is a viable and active market for such products.

What is being seen is that the market for such products is modest and this is because the products are essentially provided by generators. The market is typified as being relatively low in competition (eg in NSW there are only three generators, in Tasmania only two and in SA only three significant generators. As a result the derivatives markets are effectively closely controlled. This is made worse in those regional markets which are identified as being subject a dominant generator able to exercise market power at system demand less than the peak demands frequently recorded.

As volatility increases, generators are deciding to reduce the length of forward contracts in the NEM and are offering such contracts now of 2-3 years duration, in contrast to the 5-10 year contracts available a decade ago. In contrast, the WEM is typified by having long term contracts offered by generators.

The arguments put by the AEMC are only valid if there is a liquid derivatives market, and the AEMC should be aware that this is not the case in the NEM.

Expectation of new generation

Reliability in the NEM has been provided by there being adequate generation to meet demand. It is true that significant new generation has been provided in the NEM, but the AEMC contention that this is the result of the NEM market signals is indeed worthy of better analysis than just adding the amount of new generation built. Other than government initiated and supported base and mid merit generation, the preponderance of the new dispatchable generation provided has been peaking generation, and mainly in the open cycle gas fired gas turbine format.

The AEMC fails to highlight this or the reasons why so much low capital cost peaking generation has been built by retailers. If the market signals were robust as alleged by the AEMC, then there would be many more new entrants into generation than retailers and gentailers. Where are the new generation businesses? Basically there are none at all, yet if the market is as viable as the AEMC contends, then there should be many new businesses entering the generation market, just as is occurring in the WEM.

The failure of new entrants into the NEM must highlight that the market structure is failing. If this is the case then it is absurd to assume the new distortions imposed by the CPRS and xRET can be adequately managed in the most economically efficient manner.

Accordingly, the MEU does not agree that the existing framework will continue to operate in the long term interests of consumers.

The AEMC's penchant for increasing VOLL as a way to increase incentives to invest is seen when it refers to the likelihood that there will need to be:

> "…significant increases in the spot market price cap over time, in particular to ensure that the necessary peaking plant to complement intermittent wind-powered generation is economically viable" (AEMC, page 71).

This is indeed a frightening prospect.

The MEU considers that the current energy market framework is causing significant risks and that implementation of the CPRS and expanded RET will substantially increase the risks and that fundamental change to the existing frameworks are needed to manage them. The MEU notes the AEMC sees that investment in new generation is less of a concern in the WEM. What the AEMC fails to do is assess whether the WEM has features which deliver better reliability and at a lower overall cost.

Continued significant increases in spot prices and in network charges in the light of climate change policies will cause major dislocations to major industrial users.

7.1 The Existing Frameworks

The MEU disagrees with the AEMC's view that:

> "The ongoing process for promoting efficient investment in generation and transmission, supplemented by the efficient participation of the demand-side in the market, is key to ensuring that market outcomes are consistent with the long-term interests of consumers in terms of efficient costs, security and reliability." (AEMC, page 71)

The AEMC describes the desired market outcome as follows:

> "There are three elements to the desired market outcome, consistent with the NEO. First, individual market participants making decisions in response to market signals ensure that there is sufficient installed capacity provided at efficient cost at all times. This includes decisions on when, where and what type of new generation capacity to build and when existing generation capacity should be retired. It also includes decisions by consumers on when and how much to consume, given that firm commitments to reduce consumption at peak times can be a more cost-effective alternative to building new generation capacity in some cases.
>
> Second, in respect of transmission networks, the desired market outcome is for network capacity to be made available in a timely manner consistent with meeting the desired standards of reliability at least cost in aggregate. This requires, among other things, that the decisions of regulated transmission businesses do not pre-empt or "crowd out" decisions by market participants.
>
> Third, the desired market outcome is for the system operator's role to be limited to managing physical risks in the very short term in a manner, which does not distort the market. Ideally, interventions by the system operator should have a minimal impact on the

> financial risks and returns driving operational and investment decisions by market participants. "(AEMC, page 72)

The NEO states that it is:

> "To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> a) Price, quality, reliability, and security of electricity; and
> b) The reliability, safety and security of the national electricity system.

The Hon. J.D. Hill (for the Hon P.F. Conlon, Minister for Energy) in introducing a Bill for an Act to amend the National electricity (South Australia) Act 1996 on 9 February 2005, stated:

> "The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.
>
> The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense, the long term economic interests of consumers in respect of price quality, reliability, safety and security of electricity services will be maximised."
>
> "Applying an objective of economic efficiency recognises that, in a general sense, the national electricity market should be competitive, that any person wishing to enter the market should not be treated more nor less favourably than persons already participating in the market, and that particular energy sources or technologies should not be treated more nor less favourably than other energy sources or technologies".

Concerning the AEMC's three elements to the desired market outcome which it states is "consistent with the NEO" (AEMC, page 72), the MEU comments as follows:

- The AEMC's first element: if the additional installed capacity is primarily gas peaking generating capacity – i.e. it is relatively less efficient than base and intermediate load, in terms of price, and certainly less efficient in thermal terms compared to CGCT plant – it is difficult to accept that this is “in the long term interest of consumers” or that it is “least cost”, or that we have an “efficient” outcome. The current market framework distorts the signals so that they incentivise the less economically and thermally efficient generating capacity. Moreover, the market framework has not produced a competitive mix of generating capacity i.e. base, intermediate and peaking capacity. The AEMC’s stated intention for significantly higher VOLL will certainly create even more distortions in the market.

Following from the preceding paragraph, if the existing market framework is sending inefficient price signals to consumers and consumption is reduced or downstream industrial plants are closed to consumers, then there are deadweight losses generated, with adverse consequences for the economy. These deadweight losses will certainly be a less than cost-effective alternative to building new generation.

- The AEMC’s second element: the Rules (biased as they are to investment) as developed by the AEMC for transmission provide significant incentives to TNSPs to invest in network capacity and as a result consumers have incurred significantly more costs than was expected. With such strong incentives to invest and the obvious preparedness for NSPs to seek funds to invest and the AER to allow such investment at consumers’ expense, the AEMC assessment that the market is designed to support investment in network capacity has been demonstrated. However, where there is “gold plating” and over-investment (which the MEU believes to be the case), the outcomes cannot be seen as either efficient or optimal.

- The AEMC’s third element: since the commencement of the NEM, the system operator has had to intervene in the market on three occasions with the reserve trader mechanism. These have led to substantial costs borne by consumers (particularly with the third intervention).

- The AEMC’s desired market outcome: the AMC fails to recognise that the existing market framework has produced:

    - Highly volatile and riskier outcomes, which consumers have had to pay by way of significantly higher (inefficient) prices
    - Installing of higher priced and thermally less efficient gas peaking generating capacity

- o Inefficient prices (as the Rules allow generators to exercise market power (via economic withdrawal of capacity, rebidding) which enable generators to recover revenues substantially in excess of LRMC. That such inefficient prices do occur is confirmed in that generators do have market power at times and have been observed to use it at demand levels below peak demand levels[5].

The MEU's earlier submissions presented assessments on these issues, but they have obviously not made any traction with the AEMC analysts. The MEU continues to look forward to the AEMC's objective analysis refuting its views.

In the MEU's view, the CPRS and expanded RET directly contradicts the NEO in that the NEL is required to operate in a neutral sense with respect to different technologies used and with respect to existing and new participants.

The AEMC admits that the market frameworks will be tested by CPRS (and expanded RET) and that the form and speed of the transition/adjustment in investment and new technologies "is uncertain and depends on a range of factors, including how carbon prices and gas prices evolve over time, and the lead times for building new plant and networks" (AEMC, page 72).

Yet, despite this uncertainty and in our view, despite our concerns that the existing market frameworks are <u>not</u> robust contrary to the AEMC's view, the AEMC (apparently hopefully) concludes that:

> "The Rules **should be** robust enough to deal with this transition, over timeframes that the commercial drivers in the market dictate" (AEMC, page 72. emphasis added).

With respect to the RET and the need for new entry of gas peaking plant, the AEMC states that:

> "If this requires increases in the spot market price cap, then there will be a consequential pressure on the ability of contract markets to support efficiency management of the increased scope for spot market volatility" (AEMC, page 73).

The AEMC states that there are particular challenges in the shorter-term due to prevailing tight balance between supply and demand in some

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[5] For example the AER identified that Torrens Island P owned by AGL has regional market power when the regional demand reaches 2500 MW, a level some 20% below the maximum demand reached in SA. See AER report Spot prices greater than $5000/MWh South Australia: 5 - 17 March 2008TIPS

regions but this possibly reflects deferral of investment because of uncertainty over the pricing of carbon.

The MEU notes (for the record) that policy uncertainty is often referred to for deferral of investment, but in our view, the increased concentration of the electricity supply industry, especially in the generation sector and the reintegration of generation and retailers to create new vertically integrated businesses (including in intermittent generation) raises barriers to new entrants and increases the scope and likely frequency of generators exercising market power.

The effects of these "market failures" are large wealth transfers to suppliers; inefficient, perhaps monopolistic prices, and large deadweight losses to the economy.

Against the above, the MEU does not agree "that the AEMC is correct in concluding that the framework for investment to deliver desired standards of reliability is robust in the medium and longer term to the potential stresses created by the CPRS and expanded RET" (AEMC, page 73). These issues are also discussed in the following sub-section.

7.2 Capacity of the NEM Framework to Maintain Reliability at Efficient Cost

I. Electricity Transmission

The current framework for regulating transmission businesses is set out in the Rules, and the underlying principles have been carried into the Rules governing the regulation of distribution businesses.

The AEMC-determined transmission revenue Rules are so unbalanced that network businesses (transmission and distribution) faced relatively low hurdles for capital expenditure proposals. The recently concluded pricing review for NSW network businesses – where capital expenditure claims have risen very substantially from the previous regulatory period to $18billion in the current regulatory period – shows the economic damage being imposed on downstream industries. With price increases ranging from over 30% to over 50% in network charges (experienced by MEU members for 2009/10), many large consumers will be forced to restructure their business operations (relocate and/or source offshore) and lay off employment, as increases in network charges of such extent are unbudgeted. The curious irony is that larger customers are wearing significant cost imposts even though they are not responsible for causing the need for network augmentation.

The unbalanced transmission rules contain the following features that clearly over-incentivise network capital investments.

The Rules regarding capex are such that the AER is quite heavily proscribed in what can be denied in terms of a capex program and in any subsequent assessment of the actual capex incurred – this is the basis of the ex ante capex program that is implicit in the Rules.

- The capex program requires demonstration of need only for a small component of its program – for augmentation programs greater in value than $10m
- There is no ex post review of capex to ensure prudency
- Once set the NSP can use the capex allowance for any project, and need not use it for any project used to justify the allowance
- If an NSP decides to it can defer any capex project and keep the financial benefit
- The AER must include in the asset base all capex incurred without assessing whether the amounts should be included, even if the NSP incurs an unnecessary over-run in costs
- Contingent projects can be added after a reset, and the costs passed onto end users, even if the capex allowance has not been used
- An NSP can get a revenue increase by converting a capex program to network support, yet retain the full financial benefit associated with the capex allowance
- Because the NSP profits are included in the WACC, and WACC only applies to the asset base, an NSP is actively incentivised to maximise its capex program and so increase its profits.

Increases in network charges of such dimensions cannot be deemed to be efficient.

As for transmission pricing signals, the AEMC consistently makes the point that the development of a transmission system is predicated on the peak demand required to be served. As the cost of the transmission system is basically driven by assets, the cost of a transmission system reflects the peak demand it is required to manage. Yet despite this clear view that costs for providing a transmission system are related to demand, the AEMC consistently allows much of the revenue required by TNSPs to be priced on the basis of consumption. By allowing this to occur, significantly dilutes the pricing signals inherent in the transmission system.

Overall, whilst the current transmission (and distribution) framework has supported reliability, it is nonsensical to suggest that it is achieving reliability at an "efficient cost". (AEMC, page 76).

The latest NSW pricing reviews demonstrate a failure in Rules-making, as well as regulatory oversight. Indeed, with additional significant imposts likely to be made on large consumers, in light of climate change policies, the outlook for manufacturing industry in this country is dismal. The current transmission framework may have achieved reliability but it is far from optimal let alone efficient. All that the AEMC is saying is that high-priced transmission is better than having none or less. But such a situation can hardly be described as optimal or efficient. The AEMC's view appears to be that supply at any (high) price is better than no supply or that the resulting deadweight loss does not matter, provided the framework is "robust".

II. Gas Transmission

The AEMC report points out that it considers the gas transmission market framework is robust and will deliver adequate gas transmission capacity to meet the expected increases in gas demand caused by CPRS and xRET. The MEU accepts that additional gas transmission capacity has been constructed to meet new demand for gas

The residual concern that the MEU has, is that new capacity in gas transmission has been built "to order" in that the capacity built has only been to the extent that the foundation customer has sought, whereas gas transmission capacity built with government involvement has consistently provided for surplus capacity for future needs.

It is demonstrably more efficient to build surplus capacity at the time of initial construction than to attempt to build more capacity or duplicate facilities at a later time. The AEMC effectively concedes this point in its desire to implement the NERG approach for new remote generation. Thus to maintain a view that building gas transmission pipelines "to order" is more efficient than deliberately building surplus capacity is not borne out by direct experience.

Despite this concern, the AEMC has relied on **its belief** that "…the existing framework for delivering new pipeline capacity is capable of supporting…" increased demand (AEMC page 76) rather than relying on detailed analysis to support its view.

III. Energy Market

The AEMC's view on the NEM market design and the operation of the market completely ignores (and does not debate) the MEU's concerns regarding the NEM outcomes, detailed in its previous two submissions. In short:

- Additional generating capacity has been entirely gas peaking – there is no competitive mix of generating capacity since the NEM commenced.
- The NEM is highly concentrated with fewer layers and with the creation of vertically-integrated businesses, enabling prolonged and easy exercise of market power

- The NEM is highly volatile and therefore highly risky. Such features mean higher barriers to new entrants
- The NEM price outcomes bear no relationship to cost of production and are, therefore, inefficient, as they incorporate high margins of economic rent.
- The NEM does not enable negotiation of long-term contracts by large consumers
- The NEM is highly illiquid
- The high VOLL accentuates volatility, and price gouging.

The assessment by the AEMC (pages 77 and 78) are simply descriptions of how the NEM operates and of the work of the Reliability Panel. It does not provide any analysis nor debate the issues raised in the MEU's and other submissions. This is a very disappointing outcome. The resort to "policy uncertainty on carbon pricing" (AEMC, page 79) as the reason not to change the market framework because it is a temporary adverse influence only, is fallacious. Thus, the AEMC states:

> "Absent policy uncertainty, we do not see why the implementation of the CPRS and the expanded Ret should dilute the role and effectiveness of the contract market. It could be argued, conversely, that increased entry and exit should stimulate the contract market in the medium to long term" (AEMC, page 79).

The also AEMC states:

> "There is also scope for transitory market power to emerge and be exercised. While this is a feature of all electricity markets, it could be argued that the consequences of transitory market power in the NEM are potentially more significant because of the relatively high price cap in the spot market. High prices are, however, a necessary signal for new entry, and there are risks to reliability in constraining the high prices as a means of pre-empting the potential for mis-use of market power. In the medium term, new entry is the most effective remedy to excessive market power. In the shorter term, there are measures in the Trade Practices Act and energy market Rules to regulate market behaviour.
>
> As we note above, to ensure that appropriate investment signals continue to be provided we need to maintain and adjust the regulatory settings, including to amend the spot market price cap. Further, the expanded RET in particular is likely to drive the need for potentially significant upward adjustment over time to ensure that the peaking plant to complement intermittent wind-powered generation is economically viable. This will increase the risk to be managed by market participants, and therefore the cost of risk

management. Any costs associated with imperfections or limitations in the instruments available to manage risk are likely to be magnified." (AEMC, page 79)

The AEMC fails to recognise that:

- The consequences of market power, even transient, causes economic damage
- The energy market rules have been demonstrated to be ineffective in constraining market power
- The TPA is constrained by the rules and is ineffective in protecting electricity consumers from market power behaviour by suppliers.
- Higher and ever higher prices to provide "a necessary signal for new entry" (AEMC, page 79), is fallacious. It is tantamount to saying that supply at any price is optimal and efficient.

8. Convergence of Gas and Electricity Markets

The AEMC states:

> "In relation to market power, it is not evident why the growth of one particular generation technology (gas) should necessarily increase market power and the potential for its misuse. We also note that there are measures in the Trade Practices Act (TPA) and the NER and NGR to address the potential for misuse of market power where it exists. Competition from new entry and new technologies can also be an effective market response to the exercise of market power in a rapidly developing market environment. For these reasons we do not favour the adoption of further measures to regulate market power, particularly in advance of such an issue arising." (AEMC pages 87, 88)

Despite concerns raised by many stakeholders, including especially the MEU, the AEMC has failed to address the concerns by <u>demonstrating through analysis</u> why these concerns can be allayed, or even for changes in the Rules to mitigate these concerns. The MEU again reiterates its earlier comments made in its submission to the First Interim Report that convergence of the gas and electricity markets is a major issue that will be made more critical by the imposition of CPRS and xRET.

The MEU is concerned that arbitrage activities will increase as a result of increasing concentration in the supply of energy as this concentration is being replicated across all sectors – supply of gas and electricity, retailing and renewable generation – creating vertically integrated businesses and therefore increased arbitrage opportunities through internal contractual arrangements. The AEMC has not addressed these issues of reliability and cost as they affect end users. In its assessment of reliability the AEMC comments:

> "Provided gas markets are sufficiently flexible, operators of gas-fired generators should be free to purchase the level of reliability in their gas supply that they considered to be optimal. This may include paying for duplicate transportation or processing infrastructure. As noted above, reforms are already being pursued to improve the flexibility of gas markets and (in the case of Victoria) the incentives for new pipeline investment." (AEMC page 88)

This highlights the lack of interest the AEMC appears to have in relation to the issues raised by end use customers. The frequent use of making conditional assumptions (such as "Provided gas markets are sufficiently flexible…") demonstrates again the AEMC analytical flaws.

What the AEMC make no reference to is there is an implicit assumption that the gas market will adhere to conventional economic theory – that gas will be available to those who value it the most (and therefore will pay the highest price for it). In fact gas shortages are applied unilaterally to large end users of gas first with the impact of shortages not being socialized. The impact of this issue needs to be seen in light of the ability of a vertically integrated business to redirect gas from end users to power generation as is suggested to have occurred in NSW in June 2007. Here gas contracted to industrial end users was directed to generate power within the same entity because the value for electricity was higher. The retailer that contracted the supply of the gas to the end users did not have to advise the end users, but allowed the gas market to reach a point of curtailment. This curtailment was initiated by the gas network owner using its powers under the Rules and with apparent government support.

So what occurred is that insufficient gas was delivered to the gas network because the gas was valued more highly by the retailer elsewhere, despite it having contracted with the end user for the gas to be delivered. The shortage caused no impact on the retailer but significant hardship costs to the end users curtailed.

As gas will be used increasing as a primary fuel source to reduce emissions and to provide back up to intermittent generation, the arbitrage issues between the gas and electricity markets will increase, especially as there is increasing concentration of energy suppliers covering both gas and electricity supplies.

8.1 <u>Questions Raised</u>

> 8a How should reviews of market settings (such as market price caps) be best aligned across the gas and electricity markets?

Already we are seeing that alignment between market settings for gas and electricity are showing divergence, when the decisions of GMLG for the market setting for the gas STTM were established and the reasons for these are analysed.

In part it was recognised that the actual markets of electricity and gas have significant differences which impact on the market settings For example the NEM operates on half hourly settlements, whereas the Victoria gas market uses four hourly settlement periods and the new STTM for NSW and SA will use daily settlements.

In theory, the market settings should result in there being no incentive to transfer gas to electricity generation (or vice versa) as a result of the market settings. But the very differences between the market settlements prevent this ideal from being realised.

Any review of market settings need to assess the impact of the market differences.

8b Do you agree that the current energy market frameworks would allow for AEMO to effectively review the existing rules provisions relating to market interventions?

It is probable that because AEMO will manage both the electricity and gas markets (at least in NSW, SA and Victoria) then it should be able to provide advice on whether the Rules for the three different markets (ie electricity, Vic gas and STTM) can be optimised and whether its decisions on market interventions can integrate the knowledge it has of all three. Notwithstanding this knowledge, the market designs in all three have significant differences so regardless of the knowledge AEMO might have, its ability to act or implement changes will be limited by the differing market designs.

9. System Operation with Intermittent Generation

Our concern remains that the market rules and associated arrangements are written for a fossil-fuels market and that the possibility remains that, unchanged, they could be anti-competitive vis-à-vis renewable energy and demand management responses.

For the minimum carbon footprint and minimum cost to occur requires the dispatch of available demand side responses, sufficient low greenhouse footprint plant to meet the requirements of the xRET and dispatch higher thermally efficient plant ahead of lower thermal efficient plant. The MEU considers that as generator bid prices (subject to network constraints) is the only criterion for generation dispatch, the current framework is unlikely to be responsive to the stated goal of reducing carbon emissions, although the current system does dispatch the lowest offered energy only price.

The AEMC has clearly decided that it is outside their terms of reference to assess whether alternative market structure might be more economically efficient and that would concurrently achieve the aims of CPRS and xRET. The MEU observations made in section 1 above apply here.

10. Distribution Networks

The MEU notes the AEMC assessment that:

> "…a significant increase in the number of generating units connected directly to the distribution network will impact on the unpredictability of network flows, and consequently the difficulty of meeting network performance requirements. As a result, network management may be increasingly directed towards system operation requirements and efficiently connecting generation. Achieving this change in focus may impose new costs onto distribution businesses." (AEMC page 99)

The AEMC adds:

> "We consider there may be a case for providing a time limited allowance to network owners for expenditure on approved innovation projects. This is in view of the possible significant changes in distribution network investment, operation and performance driven by the CPRS, expanded RET and the developments in smart metering and smart networks. The purpose of the allowance would be to enable distribution businesses to be better prepared to meet the challenges imposed by a more dynamic network." (AEMC page 101)

The clear import of such observations is that distribution networks costs must increase and that these costs will be borne by consumers.

Already large electricity consumers in NSW have seen the distribution network costs increase by between 30-50% in 2009/10, adding millions of dollars to their costs for electricity supplies. The impact of CPRS and xRET will increase the size of the networks because the introduction of many intermittent generators will reduce further the already reducing load factors seen on networks due, in significant part, to the increasing incidence of air conditioning units throughout the residential electivity markets. Unfortunately, the approach to network charging does not provide significant price signals to these users to modify their demand profiles and this is a direct result of the Rules themselves and the application of them by regulators.

The increasing revenue allowances granted distribution networks already indicates a need for a revisit of the revenue aspects of the distribution Rules to minimise the ability of distribution businesses to seek ever increasing allowances for capex and opex which are not reflected in increasing consumption or even of demand.

The CPRS and xRET will only result in distribution businesses seeking higher allowances to the extent that some elements of the community will not be able to afford electricity or that others (particularly large industrial businesses will relocated off shore or import materials that they can no longer afford to make locally.

10.1 Questions raised

> 10a Do you agree that the energy framework for distribution is able to manage the challenges imposed by the CPRS and expanded RET?

The MEU remains concerned with the concept of large end use consumers funding surplus network capacity. The most recent NSW pricing review (applying to the current period) shows that they are being penalised by having to fund large network expansions caused by large increases in demand (not consumption). These same businesses are showing only marginal increases in their consumption raising valid complaints as to why they are required to fund expansions they do not need or use.

The AEMC's model will lead to a "blue skies" approach with further penalties likely to be imposed on large end use consumers irrespective of whether they cause the increase in demand or not.

This indicates that the AEMC should modify the revenue and pricing structures of the distribution networks so that there is more clearly a causer pays aspect embedded into the frameworks.

> 10b Is there merit in introducing formal, but temporary, arrangements to allow distribution businesses to recover the costs of accredited innovation projects?

T
he MEU agrees in principle with the AEMC concept, but that the allocation of the costs should be managed to reflect a causer pays approach and achieve greater equity based on usage of assets and load factors.

11. System Operation with Intermittent Generation in Western Australia Networks

The MEU agrees with the AEMC that there is a strong case for change in that the transparency of dispatch and balancing costs should be increased.

Of concern to the MEU is a number of "improvements" suggested by the AEMC to the WEM Rules to potentially enable a more transparent and efficient market for electricity. Whilst the MEU might support some (even all of these) it is concerned that the "improvements" being proposed might not necessarily be required to better manage CPRS and xRET requirements.

Consistently the AEMC has maintained that its brief is to assess whether the current frameworks can accommodate the imposition of CPRS and xRET, yet it seems that the AEMC is attempting to refine shortcomings it sees in the WEM rather than to address the needs the CPRS and xRET cause.

There are many good features of the WEM that are absent from the NEM, yet despite MEU urgings the AEMC has resisted making any assessment as to whether a better market framework for the NEM is possible. The MEU does not want to see the AEMC making fundamental changes to the WEM that would result in building in the bad features of the NEM.

11.1 Questions raised

> 11a Do you agree with the Commission's draft recommendation that the transparency of dispatch and balancing should be increased, and that this should be the precursor to the consideration of further reform options?

The MEU agrees that increased transparency in energy markets is a positive approach to ensuring well operating markets

> 11b Under an option to increase the transparency of dispatch and balancing, what additional information should be released?

The MEU has no suggestions for this question.

11c In a competitive balancing regime, would an obligation that generators' bids reflect short run marginal costs effectively counter any concerns regarding market power?

One of the attractive features of the WEM is that it is a capacity market and, that as a result, there is less volatility in energy pricing, and ability to contract for long periods at prices reflecting long run marginal cost of generation. Additionally, balancing is readily achieved by both supply side and demand side responses, although Verve Energy has a dominant position as a generator in the WEM and therefore has potentially the ability to use its market power to set the balancing price.

As the WEM allows for payment for capacity being provided, this intuitively seems to support a view that a generator's output would be provided at short rum marginal cost if it is to recover its LRMC over time but not more.

On this basis, the MEU sees that limiting a generator's bid for balancing power to its SRMC has some attraction. Notwithstanding support for such an approach, the MEU queries whether such an approach is necessary to manage the introduction of CPRS and xRET.

12. Connecting Remote Generation and Efficient Utilisation and Provision of the Network in Western Australia Generation

The MEU agrees with the AEMC that options be assessed to revise the existing energy markets frameworks spanning connections and network issues

The MEU concurs with the AEMC regarding the need for investigation into:

- The "unconstrained planning approach" in that an overall lower cost option might be that a higher cost out-of-merit generation dispatch for short term needs might be more than offset by the long term costs inherent in network augmentation.
- The lead in times for new network augmentations are unnecessarily long and cause delays in implementing new connections, and
- The confidentiality provisions for network connections and the queuing approach used do not provide for the benefits of sharing new connections. In this regard we see that greater sharing of information and more transparency should bring significant benefits
- The concept of the NERG approach for making common connections for multiple remote generators

The MEU remains unconvinced that the locational signaling needs revision, as the experience of the AEMC approach to locational signaling in the NEM leaves much to be desired. Notwithstanding our observations on this aspect, we do accept that an open minded review might develop a better outcome than we currently have.

The recommendation that generators should not have to make capital contributions for deep connection augmentation is not supported. Generator locational signals should encompass all of the costs that such a locational decision entails. In this regard we refer you to the comments made in section 3 above.

12.1 Questions raised

12a Do you agree with the Commission's draft recommendation as to options and the efficient utilisation and provision of the network in the SWIS?

We concur with some of the recommendation made but not all (see above)

12b Do you agree that the planning standard used as the basis for generator access to the network should be reviewed as a matter of priority?

Yes

12c Are there any other options that should be considered?

13. Convergence of Gas and Electricity Markets in Western Australia

The MEU notes that the AEMC has reached its conclusions based on an exclusive assessment of the gas and electricity markets, without reviewing the impacts of the decisions on end users of gas and electricity.

The MEU concedes that gas and electricity supplies under a competitive market structure based on economic principles will go to the party prepared to pay the highest price in the event of a constraint in supplies.

The implication of this is that the energy supplies will not go to those that cannot afford the energy supplies at any price, as to do so will drive them out of business. Alternatively, the energy will go to those consumers who do not even know what the cost impact of their decisions is.

The main concern that the MEU has in regard to the AEMC decision in this chapter is that there are likely to be many unintended consequences of maintaining the pure economic assumption that supply must go to the party prepared to pay the highest price and in the event of a constraint, users must be constrained off.

Unfortunately, as discussed in section 8 above, when there is a constraint in gas supplies, the curtailments are focused on the same large gas users every time rather than such a curtailment being socialized. This immediately creates inequity in the rights to gas supplies and does not allow the user curtailed its right to pay the market price for gas. As occurred with the Varanus Island curtailment, large gas users were unable to access gas "at any price".

Until the AEMC can solve this basic inequity, the MEU remains of the view that the issue of convergence between gas and electricity markets is still an open issue, especially in WA where such a high proportion of gas is used for electricity generation and users of electricity do not see the impact of gas curtailments made on manufacturing industry which is where much of the curtailments in gas supply are focused.

14. Reliability in the Short Term and Longer Term in Western Australia

The MEU concurs with the AEMC that the fundamental design of the WEM has delivered adequate reserve capacity to ensure there will be little or no risk of there being a lack of reliability in the short and longer term.

The fact that the WEM does not need such intermediate intervention as is proposed for the NEM in terms of higher market price caps and expanded programs based on Reserve Trader to be operated by AEMO provides a strong indication that there are elements of the NEM design that should be changed to make the NEM more reliable and less subject to increased risks to participants and the need for intervention by the market operator.

The AEMC proposes that the WEM could be improved by better and more accurate reporting on demand side capability and use of distribution connected generation used as back up in the event of power loss. We agree that both of these approaches warrant greater investigation. The MEU considers that transparency is a major element of a competitive market.

We are aware that a number of WAMEU members have contracted to load shed in the event of power supply shortages and that the WEM design encourages this feature. That the NEM lacks this ability has been a significant detriment in the NEM.

The MEU considers that the AEMC should look more closely at the benefits the WEM design provides to ensure adequate incentives to invest in new generation and encourage demand side participation in ensuring a higher level of security than the NEM without the high risks the NEM imposes on participants.

The MEU continues to be concerned that the tight gas supply arrangements for the SWIS presents a significant issue for the WEM, Despite these concerns, the AEMC has concluded that the gas market structure is likely to deliver adequate gas supplies in the long term to ensure reliability in the WEM (see AEMC chapter 6), even though the WEM is heavily dependent on gas supplies for its generation needs.

15. Northern Territory

The AEMC has effectively determined that the NT electricity and gas supply arrangements are such that the imposition of CPRS and xRET can be accommodated in the current design.

The MEU would agree that this is probably the case as the electricity supply arrangements that exist in the NT are based on a vertically integrated government owned utility (Power and Water Corporation – PWC). That this is the case despite a supposedly open market for new entrant generation and large consumers, highlights the failure of the current NT electricity market design to introduce effective competition.

As PWC has an effective monopoly in the provision of power at generation, network and retailing levels, it operates on a cost plus basis. The necessary costs that PWC will incur as a result of CPRS and xRET can be collated and passed onto NT consumers quite readily.

The aspect of the NT market that the AEMC has not addressed is that the NT government has signaled its desire to increase competition in the supply of electricity in the Territory, but has yet not provided details as to how this might occur. The MEU considers that therefore the AEMC should qualify its report to include an observation that should the NT government elect to change the current electricity market design in the Territory, it take into consideration the CPRS and xRET impacts into its revised design.