MEU Inc

Major Energy Users Inc.

Australian Energy Regulator

The Regulatory Test version 3 and Guidelines

A submission by MEU
on
The draft Regulatory Test v3 and Guidelines

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Executive Summary

The Major Energy Users Inc. welcomes the opportunity to comment on the AER`s Regulatory Test, Version 3. MEU members have had extensive debates with the AEMC, the ACCC, ERIG and with officials over the years concerning shortcomings in previous versions of the RT. It is pleasing to note the fresh policy perspectives emerging recently on this matter, in particular, on the issue of "consumer benefits".

The AER`s Version 3 goes a fair distance in addressing our previous concerns, especially in introducing the competition benefits criterion to be assessed on a national basis. This is strongly supported by the MEU.

The two options provided for calculating the competition benefits, however, appears extremely complex, and time and resource intensive. The MEU, accordingly, suggests that there is a need for more detailed guidance to be provided to TNSPs in how these benefits are to be calculated. As the ACCC/AER has already developed tools for assessing constraint costs, these should be used as the basis for this guidance to TNSPs.

The MEU further suggests that the AER should propose a less complex approach to calculating competition benefits with respect to smaller augmentations to avoid unintentionally discouraging such projects from proceeding.

Finally, the MEU suggests that the discount rate to be applied in preparing net present values for future cash flows should be re-addressed and the rate be related to the electricity costs or prices paid by consumers, rather than allowing the rate to be greater then the WACC used for the reset of revenue.

1. The Background

By late 2005, the MCE had noted significant concerns with the way the Regulatory Test (RT), as developed by the ACCC, operated in regard to providing clear directions for the development of needed infrastructure in the electricity supply chain.

In an (undated) brief web-posted in early 2006 by the AEMC, the MCE provided a set of principles which the MCE considered would assist in better defining the RT and so assist in achieving the objective of the National Electricity Law. These principles comprise the following:-

The AEMC should draft Rules to capture the following policy intent:

1. The *regulatory test* must have as its purposes the identification of *new network investment* or non-network alternatives that:
   (i) maximise the net economic benefit to all those who produce, consume and transport electricity in the market; or
   (ii) in the event the option is necessitated to meet the service standards linked to the technical requirements of Schedule 5.1 of the Rules or in applicable regulatory instruments, minimise the present value of the costs of meeting those requirements.
2. The *regulatory test* must be used by NSPs in the assessment of all new network investment in accordance with the Rules and with a level of analysis commensurate with the scale and size of the new network investment.
3. The *regulatory test* must be based on the principles of cost-benefit analysis as a means of economic discipline, thus satisfying the overarching objective to deliver efficient transmission investment, not simply more transmission regardless of the economics.
4. The *regulatory test* must ensure that all genuine and practicable alternative options to proposed *new transmission network investment* are evaluated by NSPs without bias, regarding: energy source; technology; ownership; the extent to which the *new transmission network investment* or the non-network alternative enables intra-regional or inter-regional trading of electricity; whether the new network investment or non-network alternative is intended to be regulated; or any other factor. This is to ensure NSPs do not favour network-only investment, and that the most efficient solution for the NEM as a whole is progressed rather than the investment that is internally most efficient for the NSP.
5. To allow NSPs to recover the efficient costs of maintaining a secure and reliable power system for end-users, the *regulatory test* must reflect the requirement for NSPs to meet network performance standards linked to the technical requirements of Schedule 5.1 of the Rules or in applicable regulatory instruments, while minimising the present value of the costs of meeting those requirements.
6. To promote confidence in the *regulatory test*, and minimise avenues for legal dispute, the *regulatory test* must be transparent, robust, defensible and capable of consistent application.
7. The *regulatory test* must be consistent with the basis of asset valuation determined by the AER for the purposes of clause 6.2.3 of the Rules to ensure internal consistency within the Rules.

The AEMC had previously determined[1] that (page 27):-

> "…the role of the [Regulatory] Test is to promote efficient investment, regardless of whether that investment is regulated or unregulated, or is in network assets or nonnetwork alternatives. In doing this, it acts as a filter for investment proposals, by revealing information regarding likely investment alternatives, ensuring that inefficient proposals are rejected and efficient proposals are identified and have incentives to proceed. This may occur either through the linkage between the Regulatory Test and the process for determining the regulated revenue of a TNSP, or through the greater certainty for the proponents of efficient non-transmission options that returns will not be undercut by the construction of a sub-optimal, competing transmission line."

In its brief to the AEMC, the MCE noted that there had been concern about how the objective might be addressed by the RT and provided the following view as to what it considered was the long term benefit to consumers (see following box)

<u>Long term benefit to customers</u>

Most network investment is undertaken to maintain network performance requirements, including reliability standards. Consequently, if the proposed Rule change promotes efficient investment in the manner described above, the long term interests of consumers of electricity will be promoted in respect to reliability and security of supply. Also, the reliability and security of the national electricity system will be enhanced.

Where this involves *interconnector development*, efficient investment can increase system security by allowing reserves to be shared between regions. This creates an efficiency benefit by potentially reducing region specific reserve requirements.

Where a particular transmission investment option is the most effective means of facilitating competition (for example, by promoting competition between generators) the new *regulatory test* arrangements will enable the identification and approval of that option. As such, competitive transmission investment options will proceed and the long term interests of consumers of electricity will be promoted in respect to the price of the electricity that they consume. Where transmission investment is not the most efficient means of facilitating competition, the new *regulatory test* arrangements will help to identify it as such in the long term interest of consumers.

In the excerpt above, the MCE specifically points out that by "facilitating competition (for example, by promoting competition between generators) the new regulatory test arrangements will enable "… competitive transmission investment options [to] proceed and the long term interests of consumers will be promoted in respect to the price of the electricity that they consume."

It is noted that the wording of the draft new Rule for the RT, as proposed by the MCE for ensuring competitive conditions, has significant common wording with

[1] AEMC Final Rule Determination, National Electricity Amendment (Reform of the Regulatory Test principles) Rule 2006, 30 November 2006

the final Rule as set out by the AEMC. In particular, the MCE proposed that the RT:-

(4) ensure that all genuine and practicable alternative options to proposed *new network investment* are evaluated by *Network Service Providers* without bias, regarding:

(iv) the extent to which the *new network investment* or the non-*network* alternative enables *intra-regional* or *inter-regional* trading of electricity;

and this wording is essentially retained by AEMC in its "Rule as made".

Rule (5.6.5A(c) (3) requires the TNSP and the AER to:-

> "...ensure that the identification of the likely alternative option referred to in subparagraph (1) is informed by a consideration of all genuine and practicable alternative options to the proposed *new network investment* without bias regarding:
>
> (iv) the extent to which the *new network investment* or the non-*network* alternative enables *intra-regional* or *interregional* trading of electricity;

It was in relation to this element of ensuring competitive conditions that, during the AEMC review process, caused the greatest amount of concern for consumers. Consumers noted that:-

- they pay for the provision of the transmission network
- when there is a constraint in the network, they pay the premium in generator prices caused by the reduction in competition between generators

The AEMC totally rejected the argument that consumers might receive a benefit from a TNSPs` investment in a network augmentation to limit the market power of a generator, on the basis that economic efficiency might be better served by potentially encouraging new investment in generation, that in turn, might result in a solution which might better provide for the "long term interests of consumers"[2].

It was therefore not seen as competitively neutral that consumers could not cause transmission investment to be implemented if the net result was a reduction in power prices caused by greater competition amongst generators, which more than offset the cost of the implementation of the transmission augmentation.

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[2] The MEU would make the comment that this might be good economics but it is also founded on the assumption that the downstream investment will remain a consumer of electricity and not relocate, causing a net loss of consumption

In its determination the AEMC referred to the differentiation between consumer benefits (as suggested by consumers) versus market benefits (ie benefits which are neutral when assessing the tensions between producer and consumer). The AEMC opined that when assessing consumer benefits only this might incentivise sub optimal transmission investment when alternative solutions might provide a better outcome, or where investment signals for new generation might be muted by "inefficient" investment in network solutions.

The AEMC concluded (pages 55 and 56) that:-

> "The Commission believes that the purpose of the Regulatory Test as set out in clause 5.6.5A(b)(1) is consistent with the NEM Objective. The long term interests of consumers of electricity are best served by an industry in which all sectors – regulated or unregulated – operate on an efficient and sustainable basis. The NEM objective is not consistent with an approach in which a reduction in profitability in one part of the industry (production) is interpreted as a "benefit" to consumers. The Commission considers that all consumers – residential, commercial or industrial – have an ongoing interest in the reliable supply of electricity at an efficient cost and that it is in consumers' interests to ensure that this sector is adequately funded. A regulatory regime that does not reasonably compensate investors is not sustainable, in the sense that financing will become increasingly costly or private sector investors will exit the industry altogether."

The structure of the RT

In fact the RT has two limbs – the reliability limb and the market benefit limb. The AEMC noted that there was little contention about the principles used to assess the reliability limb of the RT and that most of the attention (particularly from consumers) was focused on the principles behind the market benefits limb. The AEMC concluded (page 37) that:-

> "... the Commission has taken the view that there would be merit in retaining the distinction in the principles between network augmentations that (primarily) capture reliability benefits and those that achieve market benefits, since:
>
> - The overwhelming majority of investment in the NEM is undertaken under the reliability limb of the Test;
> - The Rules and various jurisdictional regulations prescribe a broad range of reliability targets that NSPs must meet, as well as direct and indirect references to reliability and security objectives; and
> - Changing this aspect of the Regulatory Test might risk unacceptable delays to reliability investment."

The outcome of the AEMC deliberations is that it essentially retained the principles put forward by the MCE, that there be two "limbs" of the RT (the reliability limb requiring less evidentiary support than that for the network augmentation limb), and that to ensure competitive neutrality, the test for augmentation be market based and not consumer based.

Both the MCE and AEMC determined that the AER was best placed to develop the detail of the RT and guidelines for its implementation.

It was subsequent to the issue of the AEMC final decision that CoAG, on the basis of the ERIG report issued a communiqué relating to the issue of the Regulatory Test. In that communiqué, CoAG states, it

> *"...has also agreed to a revised network planning and consultation process, replacing the current 'Regulatory Test'. The AEMC will be tasked with advising on amalgamating the Regulatory Test criteria of reliability and market benefits and broadening the latter's definition to include national market benefits. This will allow proposed transmission projects to be assessed against meeting both local reliability standards and their ability to maximise benefits to the national market. This is intended to recognise the broader national benefits which may be achievable from investment opportunities whilst encouraging and ensuring those justified solely on reliability grounds are delivered in an efficient and timely manner."*

The MEU wrote on this matter to AEMC[3] shortly after the CoAG communiqué, seeking the AEMC to incorporate the CoAG considerations into its then current reviews, including the Regulatory Test review.

The AER is expected, therefore, to ensure that this CoAG direction is incorporated into the details of the revised Regulatory Test.

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[3] See appendix B for full text of the letter

2. The RT and changes since version 2

At its most fundamental, the RT market benefits limb, is all about augmentation of the network to relieve constraints to allow freer access of generators to the NEM, whereas the reliability limb is all about relieving constraints which impact the delivery of power to consumers.

In its explanatory statement[4] (page 4) the AER comments:-

> "The regulatory test is an economic cost-benefit test used by transmission and distribution businesses in the National Electricity Market (NEM) to assess the efficiency of network investment. The AER considers that maintaining the regulatory test in its current form, with some amendments to ensure consistency with the amended NER, simplify the test and improve its clarity, is appropriate."

On page 8, the AER provides more clarification:-

> The regulatory test is an economic cost-benefit test used by transmission and distribution businesses in the NEM to assess the efficiency of network investment. It consists of two limbs:
>
> - *The reliability limb*- this is applied to reliability driven augmentations which are based on service obligations imposed by the NER or state legislation, regulations or statutory instruments. A reliability augmentation will satisfy the test if it is the least cost option considering the total costs of alternative options to those who produce, distribute or consume electricity in the NEM.
> - *The market benefits limb*- this is applied to non-reliability driven investment. New investment will satisfy the test if it maximises the net present value of the market benefits having regard to alternative options, timing and market development.

Thus reliability is demonstrably served if the result of a cost benefit analysis shows that the preferred option is the least cost, but a market benefits cost benefit analysis must show the maximum market benefit.

On page 4, the AER goes on to state:-

> "The AER's proposed revisions to the regulatory test reflect two of the key requirements the NER places on the market benefits limb of the test:
>
> - a procedural requirement to gather information on alternative options and
> - introduction of the notion of 'likelihood' in the consideration of alternative projects.

[4] Proposed Regulatory Test version 3 & Application Guidelines, Explanatory Statement, July 2007

The MEU considers that there is one major difference between the old RT and the requirements of the new RT. This relates to the scope of the market benefit. Whereas the ACCC RT examined the RT in relation to the region in which the augmentation was to occur, the new RT requires the AER to examine the market benefit on a national basis.

This change has profound implications as in the NEM each region has its own reference price, but there is no price differentiation within a region. The RT must now address at least two salient points:-

1. The RT must examine the implications of the augmentation in terms of inter-regional trade – effectively the impact of any constraint on competition between generators in different regions, and
2. The value of the augmentation to consumers which might result from access to generation in an adjacent region.

Rule (5.6.5A(c) (3)(iv) requires the TNSP and the AER to:-

> "…ensure that the identification of the likely alternative option referred to in subparagraph (1) is informed by a consideration of all genuine and practicable alternative options to the proposed *new network investment* without bias regarding:
>
> > (iv) the extent to which the *new network investment* or the non-*network* alternative enables *intra-regional* or *interregional* trading of electricity;

This raises the question as to how this requirement might be implemented within the RT.

The application of the RT has to be examined in relation to the changes that have been made to the Transmission Revenue Rules promulgated by the AEMC late in 2006, with particular reference to approvals for capex.

The reliability limb implies that a reliability augmentation (which comprises the bulk of augmentations) will be the lowest cost option for achieving the desired reliability outcome, and the capex required for this purpose will be included in the capex approved by the AER in a revenue reset. The control of the capex for the RT will be covered by the controls for capex included in the Rules.

This implies that the Rules for controlling capex have primacy over the RT in determining whether the investment made under the RT has been demonstrably efficient.

2.1 The RT and inter-regional trade

The RT is now required to address matters on a national basis and not on a regional basis.

Historically, augmentation of the regional network has not resulted in major concerns. In fact most of the intra-regional augmentations have been developed on the basis of the reliability limb of the RT and therefore have not created the concerns that inter-regional augmentations have. As the price impact resulting from intra-regional constraints arises from out-of-merit order dispatch, and there is no intra-regional price to drive comparisons, consumers cannot readily see the impact of the constraint on regional prices.

The ACCC (and later the AER) has been attempting to develop a tool for measuring the impact on prices of intra-regional constraints and the outcome of this work can be seen in the Decision of the AER on Indicators of the market impact of transmission congestion, released 9 June 2006. The AER has provided reports for the last three years providing a better understanding of the costs of congestion based on using these tools for assessing congestion costs.

Because of the lower threshold of proof required for "reliability" augmentations under the RT, a TNSP (which are predominantly regionally based) can and does carryout significant amounts of augmentation under the reliability limb, even if it could be construed that the work should be considered under the market benefit limb – probably as there is little ability to clearly differentiate between the two "limbs" in intra-regional matters.

However, the major change to the RT impacts inter-regional augmentations. As noted in section 1 above, it was this element that consumers considered caused the most concern to them. As the constraint on an interconnector caused uncoupling of inter-regional prices, consumers could see the regional generators using their market power to increase prices in the region. This price impact is seen by consumers as an inappropriate and unwarranted cost premium. The ACCC and AEMC however, saw this cost rise as a transfer of wealth between consumers and generators in the region, which therefore resulted in no net market benefit.

The AEMC went on to point out that effectively this price rise is a signal for new investment in generation and that in the long term, would provide additional investment in generation in the region. As such, this expected investment in generation is seen by the AEMC to be economically efficient and in the "long term interests of consumers". The MEU, while not agreeing with this view, notes that this is the basis for the AEMC's rejection of the consumer benefits criterion sought by MEU to be included in the RT.

The AEMC argument has validity as long as the constraint is considered to be a regional issue. The introduction of the national impact of a constraint changes this view considerably.

The transfer of wealth argument has to be assessed in a new light. It becomes not just an issue of wealth transfer between generators and consumers within a region, but an issue of whether the constraint has prevented generators in an adjacent region from accessing the higher priced region. It is an issue of competition between generators.

That there might be a loss of generator competition within a region due to an intra-regional constraint has been an issue which has been addressed by out-of-merit order dispatch, with the outcome of this practice not being able to be clearly seen. An inter-regional constraint highlights the cost impact of this constraint, as the regional price differential shows this "writ large".

The question that is implicit in Rule (5.6.5A(c) (3) (iv), is how does this loss of potential for inter-regional trade get valued? The AER has determined[5] (page vi) that:-

> "The market impact of congestion is the cost to the market of having higher cost generation dispatched when lower cost generation is available."

The AER has adopted three separate measures for assessing the cost of a constraint (see page vi)[6], viz:-

- the total cost of constraints (TCC)
- the outage constraint cost (OCC)
- the marginal cost of constraints (MCC)

It is, however, important to note that the development of these indicators of constraint costs is related to the actual bidding patterns of generators and so each of these rely to a greater or lesser extent on the price differential between a generator that has been dispatched out-of-merit order in preference to a generator willing to be dispatched at a lower price but prevented from being so because of a constraint.

The import of this AER Decision is the only identifier for assessing the cost of a constraint, that the AER has been able to develop is based on pricing differentials between when a generator has been dispatched, and when there is a generator willing to be dispatched and unable to be so due to a constraint.

The expectation of MEU is that this same approach used by the AER to provide a value for the cost of a constraint, will also be used to develop the costs associated with relieving this constraint by an augmentation in the cost benefit analysis under the RT.

With the tools available to NEMMCo it was able to provide costings to the AER of intra-regional constraints, with NEMMCo identifying the actual out of merit order dispatch price and the dispatch price that would have eventuated in the absence of the constraint. This provides a useful tool in assessing the costs of intra-regional constraints, and the proposals for augmenting the network to relieve them.

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[5] AER Decision on Indicators of the market impact of transmission congestion, released 9 June 2006

[6] See appendix A for the detail of how these measures are valued

In the MEU`s view, the new RT must be crafted so that it can clearly provide guidance to TNSPs in the use of the tools and approaches already developed by the AER for assessing the impact of constraints in the network and so adding to the quantification of benefits arising from the proposed augmentation.

2.2 The RT and Approved Capex

The new Chapter 6A Rules as pertaining to capex for TNSPs are changed significantly from the basis on which the original RT was based. The new Rules require:-

6A.6.7 (b) The forecast of required capital expenditure of a *Transmission Network Service Provider* that is included in a *Revenue Proposal* must:

(1) comply with the requirements of the *submission guidelines*;

(2) be for expenditure that is properly allocated to *prescribed transmission services* in accordance with the principles and policies set out in the *Cost Allocation Methodology* for the *Transmission Network Service Provider*;

(3) include both:

(i) the total of the forecast capital expenditure for the relevant *regulatory control period*; and

(ii) the forecast of the capital expenditure for each *regulatory year* of the relevant *regulatory control period*; and

(4) identify any forecast capital expenditure:

(i) that is for a *reliability augmentation*; or

(ii) that is for an option that has satisfied the *regulatory test.*

S6A.2.1 (f) **Method of adjustment of value of regulatory asset base**

Except as otherwise provided in paragraph (c), (d) or (e), the value of the regulatory asset base for a *transmission system* as at the beginning of the first *regulatory year* of a *regulatory control period* must be calculated by adjusting the value (the '**previous value**') of the regulatory asset base for that *transmission system* as at the beginning of the first *regulatory year* of the immediately preceding *regulatory control period* (the '**previous control period**') as follows:

(1) The previous value of the regulatory asset base must be increased by the amount of all capital expenditure incurred during the previous control period, including any capital expenditure determined for that period under clause 6A.8.2(e)(1)(i) in relation to *contingent project*s where the *revenue determination* has been amended by the *AER* in accordance with clause 6A.8.2(h) (regardless of whether such capital expenditure is above or below the forecast capital expenditure for the period that is adopted for the purposes of the *transmission determination* (if any) for that period).

The import of these clauses is that:-

- clause 6A.6.7(b) requires a TNSP to include in its planned capex program details of reliability capex and of augmentation options that comply with the RT.

- clause S6A.2.1(f) requires that now capex actually incurred must be rolled into the RAB *without any further examination as to its prudency and efficiency.* This approach is referred to the ex ante approval of capex and precludes any ex post review.

When considered together with the RT, despite the fact that a TNSP has evaluated, in detail as required by the RT, the costs for various options in addressing an augmentation need, there can be no subsequent verification by the AER of actual TNSP capex to adjust the basis on which it demonstrated under the RT that its network solution was the lowest cost (in terms of a reliability augmentation) or provided the maximum market benefit (in the case of other augmentations), that the actual outcome as forecast was in fact replicated.

An ex post review (if permitted) could allow the AER to adjust the actual capex for the augmentation to reflect the lowest cost option should the TNSP over-run on its capex, whether this was caused by poor management or by a low estimate of costs. Because of this, there is potential that a TNSP could deliberately underestimate the capex requirements so that a network option is the best outcome resulting from a RT assessment. At worst, the impact of the low estimate would apply to the TNSP for the very limited time until the next reset, and then the actual capital will be automatically rolled into the RAB, effectively passing the ongoing costs of the over-run onto consumers.

A competent TNSP could even reduce this impact to zero, by manipulating its capex program so that the over run in one area is offset by a timing change in another through deferring the capex program of the next element to be built.

In the MEU`s view the **new RT must recognise the potential for TNSPs to "game" the RT so that network solutions can be provided with a positive bias as a result of the capex approval and roll in requirements of the redeveloped revenue Rules in Chapter 6A.**

3. The RT as proposed by AER

As an overall assessment, the MEU considers that the AER has provided a sound basis for the Regulatory Test.

The approach used to ensure that sensible and viable alternatives are considered and costed for a net benefit assessment is broadly supported. This element of the RT has consistently provided, over all versions, an imposed rigour on proponents to ensure that the optimum solution to resolving a network constraint has been identified.

At its most fundamental, consumer concerns about previous versions of the RT lie with forecasting the benefits that result from an augmentation. Consumers have been of the view that whilst costs can be reasonably accurate, future benefits have been consistently understated, and that sensible (from a consumer viewpoint) augmentations have not proceeded.

In particular, consumers have seen needed inter-regional augmentations not proceed because of differences of view as to what constitutes a benefit, and how this was costed. These differences have at times resulted in appeals to the Courts in order to prevent some needed inter-regional augmentations proceeding, and at other times prevented needed inter-connection being seen as beneficial due to the understating of likely benefits.

3.1 Reliability Augmentations

The revised definition of a reliability augmentation is:-

> "... that a *transmission network augmentation* will be regarded as a *reliability augmentation* so long as it is principally necessitated by a *reliability requirement*."

The AER notes that this reflects a change from the previous provision where a reliability augmentation needed to be solely necessitated by a reliability requirement. The intent of this change seems to allow for an augmentation which will deliver both reliability and market benefits, and can be assessed as a reliability project if the majority of its need is driven by reliability factors.

It would seem that the reverse should also apply – that a market benefit augmentation might provide for increased reliability. In this case the benefit of the increased reliability needs to be added, creating a need for the AER to identify how this increased reliability can be valued.

3.2 Competition benefits in the market benefit limb

As previously pointed out, the market benefit limb of the RT has created the most concern with consumers, as there has been a view that the costs to consumers relating to the ability of generators to exert market power when a constraint occurs, has not been seen as being part of the RT. The reasons giving for excluding this has been a consideration that this is merely a transfer of wealth, and therefore does not add to the total benefits resulting from an augmentation.

The AER explicitly states in its guidelines that consumer benefits are to be excluded from the market benefits, reflecting the AEMC decision

> 4.1(e) For the avoidance of doubt, the calculation of *market benefit* of an option or *alternative option*:
>
> a. should not include wealth transfers between consumers, producers and transporters of electricity;

This exclusion is of concern to the MEU but equally, it accepts that the decision to exclude this, rests with the AEMC and it is not possible for the AER to reverse this AEMC decision. The market benefit does allow for the inclusion of cost impacts associated with the change in costs from increasing or decreasing thermal and/or cost efficiencies resulting from more efficient use of generation assets caused by the augmentation. The benefits arising from these inputs are required to be based on actual generator cost structures, rather than the ability of a generator to exercise market power.

When analysed, the concerns of consumers are not so much directed to the actual short run or long run marginal costs incurred by generators, but more with the outcomes of the exercise of generator market power to use constraints in the networks to drive generator pricing to levels unrelated to the costs of production by generators.

When viewed in this way, the consumer concerns are not intended to mute signals for investment in new generation, which they see would be the outcome if generators bid long run marginal costs into the market, rather than the opportunistic costs seen so frequently by consumers, and which drive the spot prices to stellar levels. An indication of this is seen in the following table

States for 2006	**Qld**	**NSW**	**Vic**	**SA**	**NEM (excl Tas and Snowy)**
% of average annual volume weighted price caused by >$300 price spikes	18.2%	20.6%	20.9%	19.4%	20.1%
Av annual time weighted regional price $/MWh	25.97	31.01	34.13	38.68	31.02
Av annual volume weighted regional price $/MWh	28.23	34.81	37.65	44.68	34.49
# price spikes >$300/MWh in 2006	27	32	47	62	168

Source: MEU and NEM Review data

This table shows that a very few inter-regional constraints have had a major impact on the spot price for electricity. The annual reports by the AER of Indicators of the market impact of transmission congestion support this view, in that inter-regional congestion is used by generators as a tool for unnecessary high bid prices. These high bid prices are opportunistic and use market power to be effective.

Unfortunately, the NEM Rules permit generators the right to opportunistically use market power to increase spot prices, and by extension, contract prices used by most consumers for electricity supply. A by-product of the exercise of this market power is to increase volatility of prices, and so increase the costs for risk management by retailers. It is noted by consumers that generators themselves provide (for a fee) much of the risk management services needed by retailers.

The outcome of this exercise of market power by generators affects consumers in two ways – directly by increasing the cost of electricity in the spot market, and indirectly by providing for a cost, the risk management tools required to manage the potential for generators to exercise market power.

Thus it is understandable why consumers see the need to use the outcomes of the exercise of generator market power as a tool to prove the need to relieve network constraints (be they inter-regional or intra-regional) to minimize the ability of generators to exercise this market power they have.

Equally, as the table above shows, this exercise of market power is able to be used infrequently. But when it is exercised, the outcome is a major cost to consumers, and the results are a significant increase in the average price of electricity.

The MEU sees that the use of the TCC and its affiliated MCC tools for quantifying the impacts of constraints is an appropriate method for allowing the market benefits limb of the RT to incorporate the impact of exercise of market power by generators.

Notwithstanding the explicit exclusion of consumer benefits, the AER does propose to include in the market benefits, an element entitled "competition benefits". The AER refers to two approaches (one proposed by Dr Biggar and the other by Frontier Economics) which might be used by TNSPs in assessing competition benefits for incorporation into the market benefits assessed for the market benefit limb assessment.

The two approaches both consider that, where market power has been used by generators to secure excessive benefits enabled by network constraints, the issue is more than a fair "transfer of wealth" matter, and needs to be addressed within the RT.

The MEU strongly concurs with this sentiment and comments that consumers do not see that where generators bid in accordance with SRMC or even LRMC, that the outcomes lead to excessive regional prices – it is when they use the network constraints combined with market power to drive prices to excessive levels, that is the major concern to consumers. On this basis if generators can (and do) use market power to extract excess revenue from consumers, it is reasonable that consumers should be able to use relief of network constraints to moderate generator ability to exercise market power.

That generators have exercised market power is beyond any doubt. ERIG (page 71) comments

> "In assessing market performance overall, ERIG accepts that, in the NEM, there is some evidence of the on-going exercise of market power. This appears to be persistent, but intermittent. **The magnitude of non-competitive outcomes appears to be such as to have a material adverse impact on the economic performance of the market**. This appears to be most significant in New South Wales." (emphasis added)

To restate the ERIG observation in terms of consumer impacts – generators have market power, they have exercised this power, and as a result have caused consumers to pay *materially* more for power than they should have.

Dr Biggar is quoted in the ERIG report (page 67) as stating

> "… generators in Australia's National Electricity Market do have a degree of market power and they exercise that market power regularly".

It is therefore essential that the impacts of the exercise of market power should be included in the RT, as network augmentation is a key element in limiting the exercise of market power by generators.

This then raises the question, does the proposal to include "competition benefits" in the market benefit test, adequately address the impact of exercise of market power.

As described by Biggar (in appendices D and E of the ACCC 2004 Decision on the Regulatory Test) the "competition benefit" would address the exercise of market power that has so concerned consumers. It was the development of the TCC (and associated OCC and MCC constraint valuations) that demonstrates how the simplistic models developed by Biggar and Frontier in the ACCC version 2 RT, might be employed in a consistent way in using the RT in the NEM.

The TCC (and OCC and MCC) is developed on an annual basis using actual outcomes, using NEMMCo records which show actually bidding practices of generators and provide generator prices which would have applied in the absence of the constraint. This allows the AER to assess in hindsight what constraint costs actually were. The development of this tool requires significant input of time and resources by NEMMCo to provide these outcomes.

In regard to developing the competition benefits using the Biggar/Frontier approaches, it is important to provide direction to the TNSPs as to the bases on which a TNSP must develop the analysis of competition benefits. Will the AER require it to:-

- set the "status quo" condition be based on average prices for the previous year or on a greater or lesser period)
- should the analysis use 5 minute dispatch pricing or the 30 minute settlement pricing (MEU suggests that 5 minute dispatch pricing provides the more accurate outcome)
- assume that these prices will remain static for the NPV assessment
- address significant exogenous issues occurring in the past (eg the 2007 drought impact, new generation added)
- accommodate expected demand and consumption growth and the potential for new generation, and if so on what basis
- assume that the bidding approaches by generators in the previous year will remain static in developing the forecast changes (this is not the assumption of Biggar and Frontier)
- develop its own view as to future bidding by the impacted generators. Direction will be required to formulate the basis for assumptions needed to establish likely future scenarios (eg are the efficiency benefits to be assessed on the SRMC for each generator to be provided by NEMMCo, are the new generator bidding practices to be based on historic approaches such as bid offers made in a "highly competitive environment" rather than when market power is exercised, if so, what constitutes a "highly competitive environment", etc)

Until these more detailed guideline inputs are developed, it becomes almost impossible for consumers to be satisfied that the simplicity of the examples provided can be extended into the immense detail that is required as an outcome of the complexity of the NEM.

On balance, the AER approach to the competition element of the market benefit calculation is soundly based and should alleviate some of the concerns of consumers. Unfortunately, developing the detail for competition benefits will require extensive work and support from NEMMCo as demonstrated by the extent of work required to calculate TCC and its affiliate.

However, the detailed implementation of the two models suggested as acceptable for calculating the competition element (Biggar and Frontier) is not at all clear and **the AER should provide much more guidance on the detail of the approaches and assumptions, as this will be needed to provide consistency of outcomes between options and alternatives.**

The MEU suggests that for very large projects such as inter-regional connectors, addressing the complex detail implicit in the Biggar and Frontier approaches to competition benefits might be warranted, but for smaller projects and intra-regional augmentations, the costs of the approaches might not be warranted.

The MEU recommends that the AER provides guidance on approaches for calculating competition benefits where the costs of the augmentation might not warrant the extensive and complex approaches implicit in the Biggar and Frontier options.

3.3 Discount rates

The AER defines what costs are in section 3 of the proposed test guidelines and what constitutes benefits in section 4.

By defining costs as the present value of current and ongoing future costs, implicitly it has to define the discount rate that has to be used in the development of the present value of future costs. The AER has attempted to do this in section 6 – discount rate.

The proposal is that the discount rate should be reflective of market conditions, requiring the discount rate to be

> "... a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector and that the type of discount rate used should be consistent with the cash flows being discounted."

The AER goes on to state that the discount rate should be no less that the average WACC used in the setting of returns on RAB for a TNSP.

The MEU has a concern that use of the wrong discount rate will lead to inappropriate outcomes. For example, the larger the discount rate the greater the bias to reflect an outcome based on low current but continuing costs such as a network support solution compared to a larger current but once-off cost network augmentation.

The MEU is of the view that rather than limiting the discount rate to a minimum of the WACC but a potentially higher discount rate, the AER should examine using a discount rate set in terms of the costs consumers see and can be related to by them. One such discount rate might be the CPI, which is extensively used by consumers when comparing current with future costs, and another might be the TNSP cost charge in terms of the change over time in the average unit cost to provide the TNSP service.

It is accepted that such a consumer based discount rate might result in a bias towards network augmentation solutions compared to using a higher discount rate, but it provides a clear relationship between the future costs incurred for the network in terms of the way consumers see network costs change.

4. Conclusions

Overall, the MEU is of the view that the Regulatory Test (and associated guidelines) provides some good guidance for TNSPs (and DNSPs) in the development of the optimum approach to demonstrating the efficacy of relieving identified constraints in the electricity networks.

The way the new RT explicitly recognises the need to assess benefits on a national basis and allows for competition benefits to be included, is supported.

As the two options for calculating competition benefits is extremely complex and intensive, the MEU concerns lie predominantly with the lack of detailed guidance provided to TNSPs on how to incorporate the necessary detail in the calculations.

It is important that to ensure smaller but needed augmentation proposals are not, not implemented because the costs of calculating the competition benefits might not be warranted due to the overall cost of the augmentation, the AER should propose a less complex approach to calculating competition benefits, so that these projects can be more quickly evaluated. Such lesser detail based on averages and broader assumptions might be a way of assessing the benefits without the expense required to encompass the detail implicit from the TCC calculations.

The MEU suggests that the discount rate to be applied in preparing net present values for future cash flows should be re-addressed, so that the rate is more attuned to the way consumers are impacted by electricity system costs and prices, rather than allowing a discount rate to be greater than the WACC used for the reset of revenue.

Appendix A

Explanations of the three measures for valuing constraints

These are provided in AER Decision on Indicators of the market impact of transmission congestion, released 9 June 2006, pages vi and vii. A more detailed explanation of these indicators is provided in Appendices A and C of the AER Decision.

The TCC estimates the benefit to the market when all transmission constraints are removed. It does this by modelling the cost of generation that would have resulted without any transmission constraints and comparing it to the actual cost of generation. The difference is the TCC.

The modelling is based on the generators' actual (historic) bids. Generators lodge bids with NEMMCO for every five-minute period in the day. NEMMCO uses the bids to determine which generators are dispatched and at what level of output. Subject to transmission and other constraints, NEMMCO dispatches generation on the basis of bid price in ascending order until demand is met. In the modelling, the dispatch price for each bid is multiplied by the quantity dispatched at that price, then summed to give a total cost of dispatch. The TCC is the difference between the cost of dispatch with and without constraints.

The OCC is similar to the TCC but only estimates the benefit to the market from removing all transmission **outage** constraints (and retaining other causes of congestion such as 'system normal' capacity limits). The AER has included this indicator because retailers, generators and other traders are particularly interested in the TNSPs' management of outages. If the impacts of the outages are not predictable or notified well in advance then it can be difficult for traders to manage the associated risks.

The third indicator, **the MCC**, estimates the benefit to the market from relieving a transmission constraint at the margin. It does this by modelling how much the cost of generation would be reduced if the transmission limit was relieved by one megawatt. The MCC is useful in helping to identify the elements of the transmission network that are the primary contributors to the TCC.

Appendix B

MEU LETTERHEAD

15 May 2007

Dr. John Tamblyn
Chairman
Australian Energy Market Commission
POBoxH166
Australia Square
NSW1215

Dear Dr. Tamblyn,

MEU Views on Congestion Management

Following on from the recent MEU submission to the AEMC's Directions Paper on Congestion Management, there are two additional matters that we would like to bring to your attention.

1. CoAG communiqué

In its response to the ERIG report, on page 4 of COAG NATIONAL REFORM AGENDA, COMPETITION REFORM APRIL 2007, CoAG states:

"These new arrangements [for an enhanced planning process for the national electricity transmission network to ensure a more strategic and nationally coordinated approach to transmission network development] will be designed to provide an appropriate balance between the delivery of a coordinated and efficient national transmission grid, and local and regional reliability and planning requirements, and be flexible enough to respond to generation and load changes.

The new arrangements will be informed by the congestion management scheme (under review by the AEMC) and efficient behaviour will be rewarded through the service incentive regime (under development by the AER).

COAG has also agreed to a revised network planning and consultation process, replacing the current 'Regulatory Test'. The AEMC will be tasked with advising on amalgamating the Regulatory Test criteria of reliability and market benefits and broadening the latter's definition to include national market benefits. This will allow proposed transmission projects to be assessed against meeting both local reliability standards and their ability to maximise benefits to the national market. This is intended to recognise the broader national benefits which may be achievable from investment opportunities whilst encouraging and ensuring those justified solely on reliability grounds are delivered in an efficient and timely manner."

In its response to the Directions Paper on Congestion Management, MEU observes that it had previously expressed concerns that the decision of the AEMC not to re-address the Regulatory Test (amongst other matters) was not sound, in that the costs of congestion are so intimately tied to the Regulatory Test (RT), and that this proscribed the ambit for future congestion resolution. That CoAG now requires the AEMC to extend the ambit of the RT to include a "national market benefit" criterion must, as a minimum, require the AEMC to recognise that there is a cost penalty for a generator (with a resulting impact flow on to consumers) wishing to be dispatched but prevented from doing so because of a constraint. This now opens for dispute the AEMC decision that the out turn costs of congestion between consumers and generators in a single region as being merely and exclusively a "transfer of wealth" between consumers and generators in the region and therefore must increase the ambit of the RT to include the impact of out turn costs that congestion causes on consumers and generators in other regions.

With this in mind we seek the AEMC's assurance that the congestion management review will readdress the Regulatory Test in light of the CoAG policy decision, and that consumers will be able to comment on the new proposals for the RT to meet the CoAG requirements.

2. Insurance products

In the MEU's submission on Congestion Management, we made reference to the costs of seeking protection from price spikes (>$300/MWh) in the NEM. In further research on this issue we came across an interesting article in the Age 24 May 2006, by the respected commentator Alan Kohler commenting at the time Snowy was being readied for sale:

"...yet last financial year [Snowy generated power at] 13.5% of its capacity. ... Snowy Hydro is not really a power company ... it is an insurance company. ...Snowy makes revenue in three ways: power generation (the least of the three), insurance contracts with power retailers, including guaranteed price caps and swaps, and, third, settlement residue auctions, which involve collecting on the difference between price across a particular interconnect - say between NSW and Victoria ..."

This accurately describes the operations of Snowy, which uses its assets to increase the value of its "insurance products" and to sell these products into multiple regions.

This supports the MEU view that if there is a cost to seek protection from a volatile market (such as the NEM) then the costs of this "insurance" must be considered a cost to consumers, which is exclusive of the "transfer of wealth" debate that has so far resulted in a stunted Regulatory Test, as far as consumers are concerned.

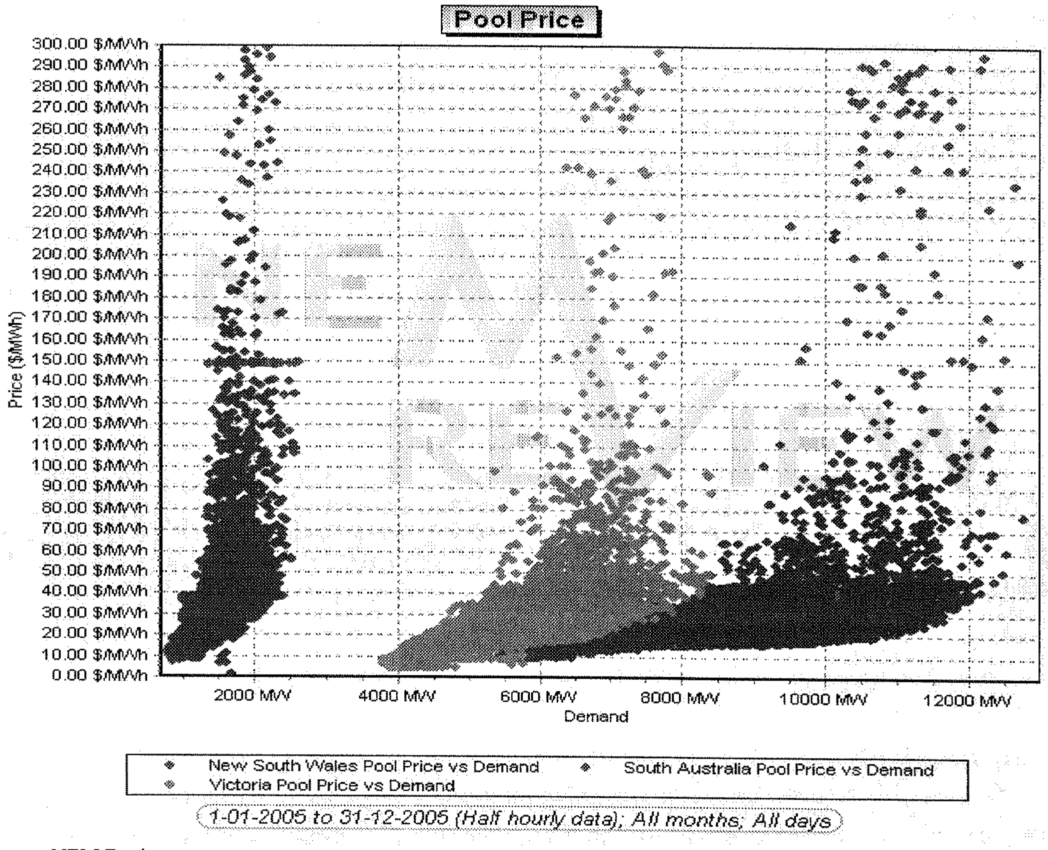
Yours sincerely

Mark Gell
Chairman

Appendix C

Generator market power – the reliability and price impacts

A review of the normal operation of the NEM shows that the relationship between price and demand demonstrates a reasonable degree of correlation (as would be expected from economic drivers), but only up to a price point which appears to be at about 3-4 times the average price of supply (i.e. about $100.MWh). The following graph shows that the price/demand scatter is certainly consistent and reasonably predictable up to a price level of $100/MWh, but beyond this point the correlation between price and demand is much less, and as the price increases, the degree of correlation continues to reduce.



Source: NEM Review

Selecting a benchmark price of $300/MWh as a reasonable expectation of maximum regional pool prices[7], represents about 10 times the average pool price and a premium at which most buyers would not normally enter into a purchase.

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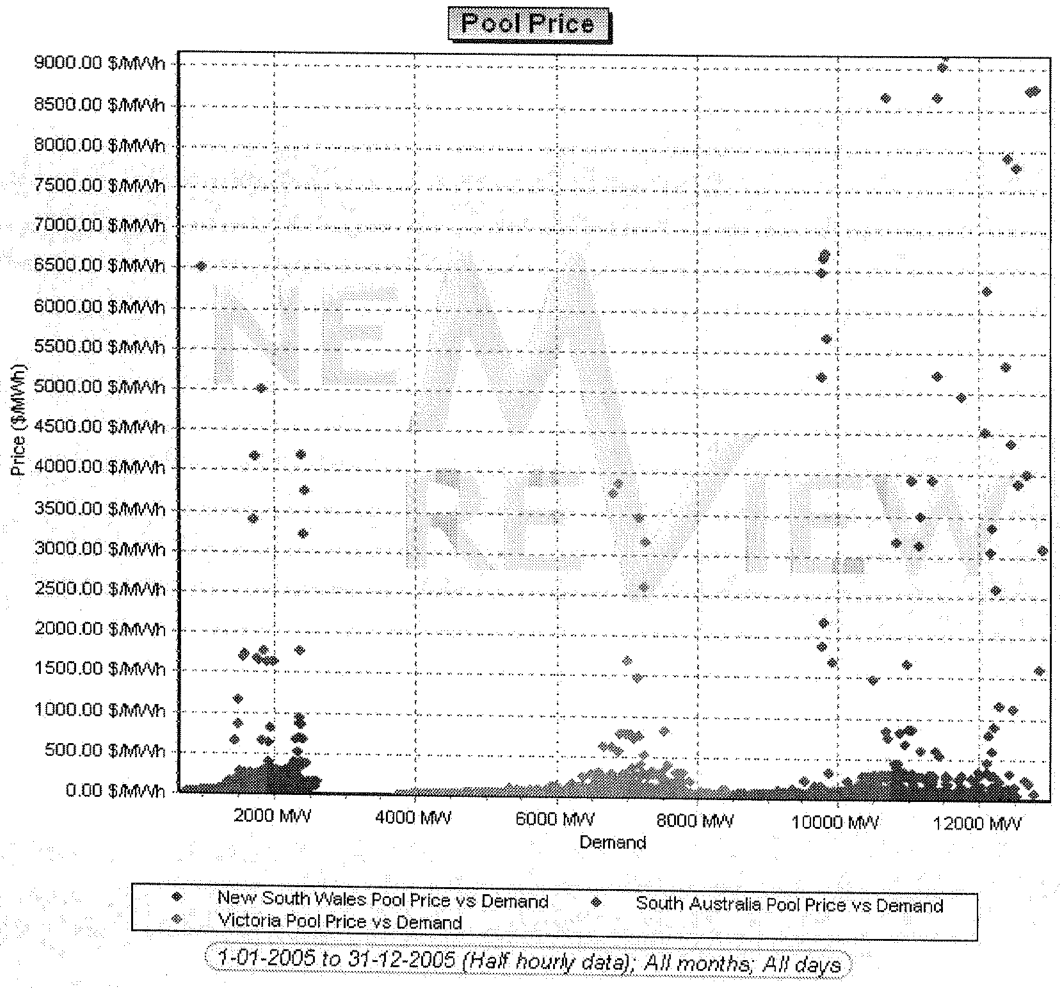
[7] This is the point up to which many retailers take "pool risk" and thereafter seek price caps from peaking generators

An expectation of a price premium is essential in the NEM, as electricity prices are not seen until ex-post.

It would appear that using a $300/MWh cap for a price/demand indication shows a reasonable relationship between price and demand than does capping the price at $10,000/MWh as the following graph shows.



Source: NEM Review

Analysing pool prices for 2005, shows that the pool price exceeded the amount of $300/MWh for only 128 half hourly periods in the four regions of Queensland, NSW, Victoria and SA. These 128 half hour periods represent less than 0.2% of all half hourly periods in the four regions. The following chart shows the price impact of these 128 spikes as a proportion of the average annual price for each region. Snowy data is excluded as it has little demand and Tasmania data was excluded as it did not operate in the NEM for the full year.

States	Qld	NSW	Vic	SA	NEM (excl Tas and Snowy)
% of average annual volume weighted price caused by >$300 price spikes	19.6%	36.6%	7.6%	10.1%	24.6%
Av annual time weighted regional price $/MWh	25.17	35.83	26.29	33.60	30.22
Av annual volume weighted regional price $/MWh	27.12	40.84	27.83	36.76	33.44
# price spikes >$300/MWh in 2005	26	67	24	35	128

Source data: NEMMCo and NEM Review

In 2002, the impact of price spikes above $300/MWh was to inflate the average pool price in the NEM by 28%[8].

In 2005, the impact of these price spikes above $300/MWh added over $8/MWh to the average annual volume weighted NEM pool price. Because of the severity of these relatively few price spikes, retailers must add significant premiums to accommodate the risks they face should such a spike occur. The very randomness of the price spikes prevents reasonable attempts to mitigate the impact of the price spike other than to buy expensive "insurance". Additionally, generators add a risk premium to manage the risks they face from these price spikes when they contract with retailers.

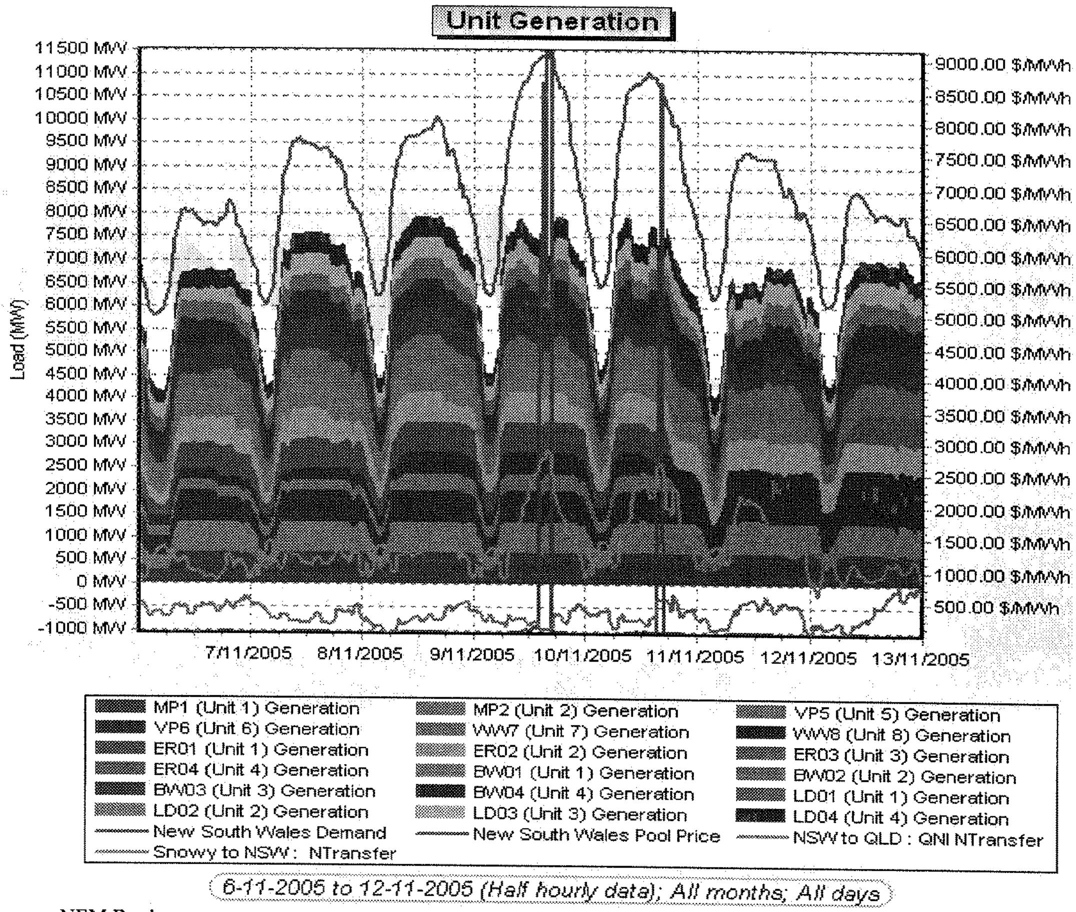
These price spikes tend to occur when generators are aware that the interconnections between regions are constrained and so allow the regional generators to set prices. This is often achieved by the dispatched generators withdrawing capacity (effectively achieved by reallocating already bid

[8] Bardak P/L, "The Effect of Industry Structure on Generation Competition and End-User Prices in the National Electricity Market", May 2005

generation into a higher price range) in an increasing demand period. The common ownership of the three large generation groups in NSW allows this practice to regularly occur in NSW.

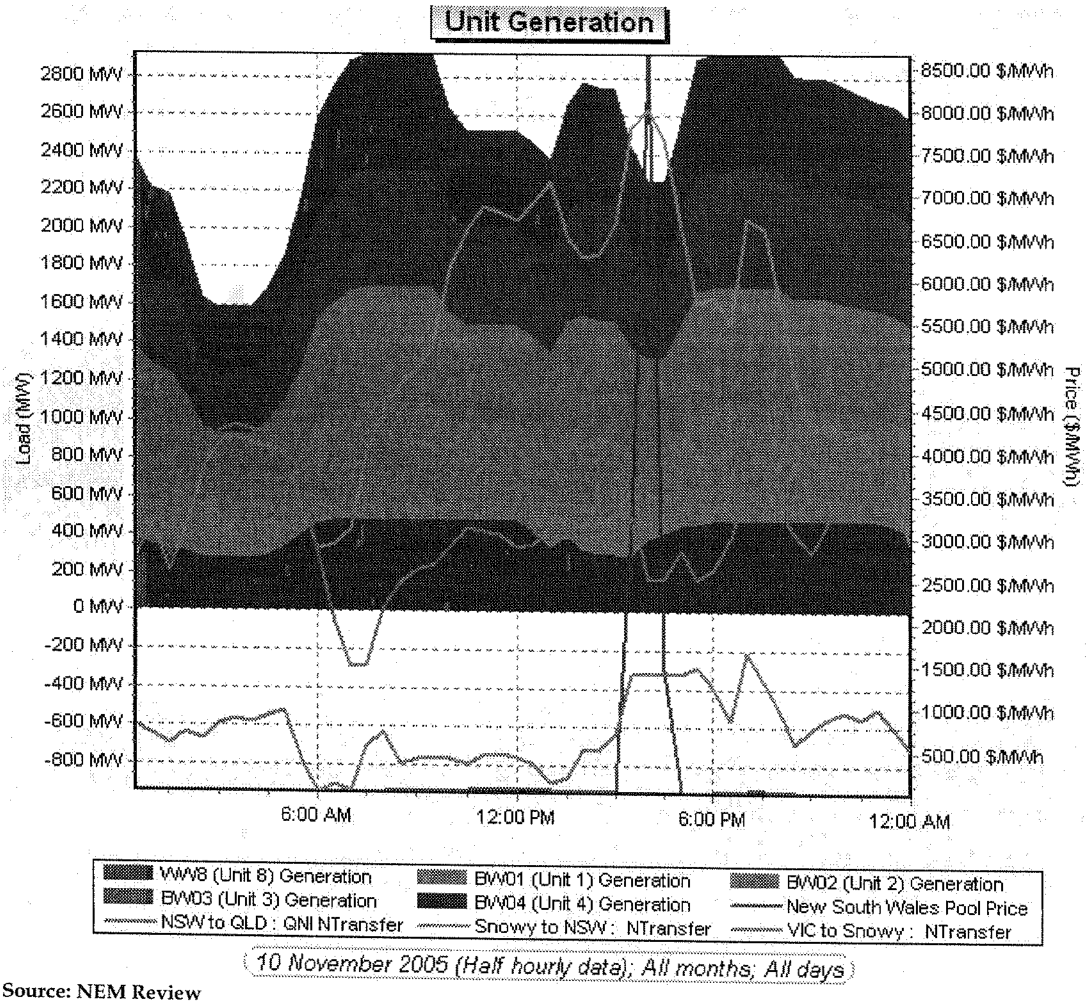
Thus it is clear that when generators use their market power, they do have a significant impact on regional pricing levels.

It is clear how the generators can easily exercise their market power. The basic concept is that when the generators see an opportunity of certain high demand and constrained inter-connectors, the generators withdraw capacity from a lower price band and rebid this at a higher price band. A review of the AER weekly report for week commencing 7 November 2005 shows this quite clearly. The price for power reached over $9000/MWh on 10 November 2005, caused by a significant withdrawal of power by base load generators from levels of dispatch they easily achieved the day before and did so later in the day examined and again on the following day. Why the price spiked was due to the constraint on the interconnectors, which when the base load generators withdrew capacity, forced higher priced generation to be dispatched.



Source: NEM Review

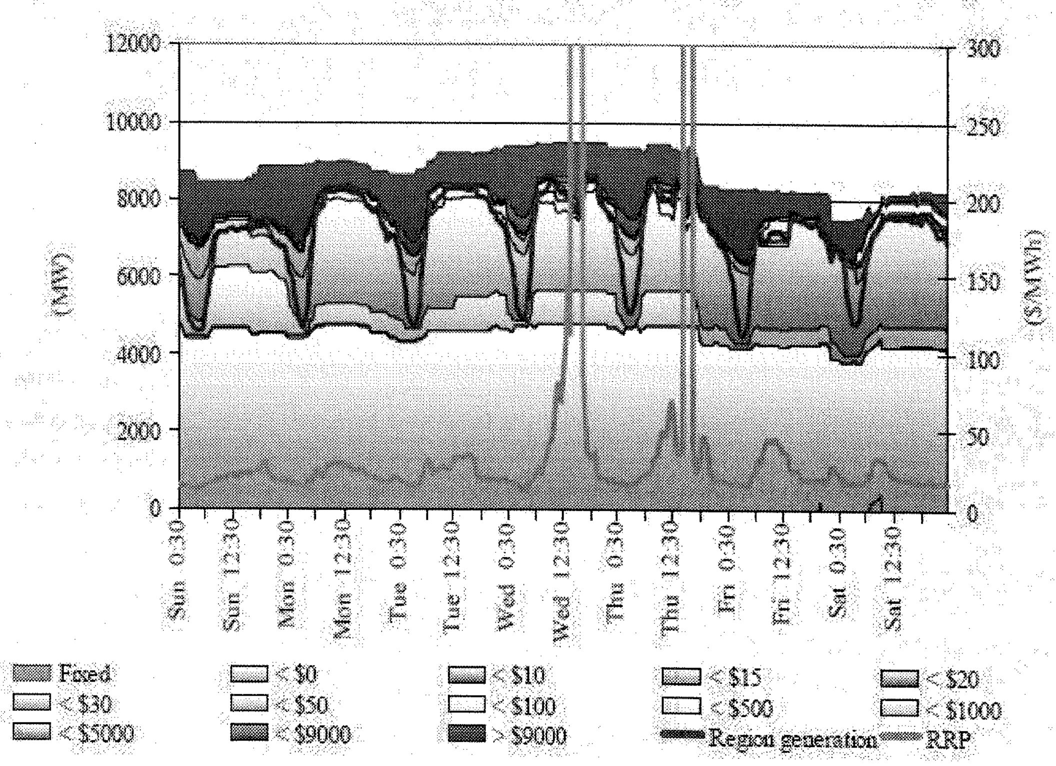
Examining the issue in more detail shows that demand peaked on two consecutive days, but on the first day (10 November 2005) there was a significant reduction in supply from certain base load power stations, totalling about 700 MW. At this same time the price spiked to nearly $9,000 and stayed high for an hour. Looking closer at that day we see who did what at this critical time.



Source: NEM Review

There was a reduction of output from five power station units, requiring Snowy to make up the difference. From the AER weekly report we see that Snowy "parks" much of its output at >$9000/MWh which the base load generators knew. Note in the following charts (courtesy of AER weekly reports) that the introduction of the >$9000/MWh (purple) band on 10 and 11 November occurs at a much lower afternoon demand level than on the other days which had a similar high demand. By marginally reducing output, requiring Snowy to generate, the five generators included in the above chart made more money than by being dispatched. We also note that at this time Snowy increased output of its Murray power stations, reducing power transfer on the interconnection between Victoria and Snowy, preventing lower priced generators in Victoria being dispatched.

Figure 52: New South Wales closing bid prices, dispatched generation and spot price



Source: AER Weekly report 6 Nov 05 - 12 NOv 05

The actions of five NSW based power stations, knowledgeable of Snowy practices, provided the perfect conditions for spiking the power price in NSW, uncoupling prices from those in the others states.

There is a noteworthy comment[9] made by Alan Kohler during the time when Snowy was being readied for sale.

> "...yet last financial year [Snowy generated power at] 13.5% of its capacity. ... Snowy Hydro is not really a power company ... it is an insurance company. ...Snowy makes revenue in three ways: power generation (the least of the three), insurance contracts with power retailers, including guaranteed price caps and swaps, and, third, settlement residue auctions, which involve collecting on the difference between price across a particular interconnect – say between NSW and Victoria ..."

This accurately describes the operations of Snowy, which uses its assets to increase the value of its "insurance products".

The purpose in describing this easy ability of generators to use regional market power is to highlight that any action taken by the Reliability Panel must be seen

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[9] The Age, 24 May 2006

in the context that generators will **always** seek ways to maximize their revenue irrespective of any Reliability Panel Review recommendations.

The very structure of the NEM permits, even encourages, generators to use their market power to create the price spikes seen in the NEM. **The primary tool used to encourage reliability in the NEM (particularly that of increasing VoLL) provides the mechanism for generators to further use their market power to maximize revenue and profits.** If reliability can be achieved or enhanced at the same time as **by reducing market volatility** this must be seen as a preferable decision when compared to the less palatable alternative of maintaining or increasing volatility.

Thus there should be an incentive for the Panel to ensure that its decisions lead to a reduction in the market power of regional generators, with the likely outcome of volatility being reduced.