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AUSTRALIAN ENERGY MARKET OPERATOR

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10 August 2009

Dr John Tamblyn
Chairman
Australian Energy Market Commission
AEMC Submissions
PO Box A2449
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Lodged via website: www.aemc.gov.au

Dear Dr ~~Tamblyn~~ John,

AEMO Submission to AEMC Review of Energy Market Frameworks in light of Climate Change Policy, 2nd Interim Report, June 2009 – Reference EMO 0001

Thank you for this opportunity to submit to this important review. Attached is a detailed submission by the Australian Energy Market Operator (**AEMO**). We apologise for the late lodgement of this submission.

As you know, AEMO formed on 1 July 2009. Prior to that AEMO officers participated in this review through submissions and direct representation from each of the:

- Australian Energy Market Operator (Transitional) (**AEMO-T**);
- National Electricity Market Management Company (**NEMMCO**);
- Victorian Energy Networks Corporation (**VENCorp**); and
- Electricity Supply Industry Planning Council of South Australia (**ESIPC**).

This submission is informed by the earlier engagement of those bodies in this process.

For further discussion, please contact David Swift, Executive General Manager, Corporate Development, on (08) 8201 7371.

Yours sincerely

Matt Zema
Managing Director and Chief Executive Officer

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NEW SOUTH WALES QUEENSLAND SOUTH AUSTRALIA VICTORIA AUSTRALIAN CAPITAL TERRITORY TASMANIA

AEMO SUBMISSION TO AEMC REVIEW INTO ENERGY MARKET FRAMEWORKS, 2ND INTERIM REPORT

Australian Energy Market Operator (AEMO)
2nd Interim Report, June 2009 – Reference EMO 0001

Executive Summary

The Australian Energy Market Operator is in a unique position to comment upon the second interim report. Our activities result in us having expertise in matters of:

- Electricity Market Operations & Settlement;
- Gas Market Operations & Settlement;
- Electricity and Gas Market Security and Reliability oversight;
- Electricity and gas emergency management;
- National Transmission Planning;
- Detailed Victorian and South Australian Transmission Planning;
- Victorian Transmission Network Service Provision, including the calculation of tariffs.

We have approached this submission from a broad perspective of our own operations.

Climate Change policies will have a profound effect upon Australian Energy Markets and over the coming decade can be expected to create a period of transformational change in energy investment and usage. This therefore represents a good opportunity to both consider whether those challenges are manageable within the current frameworks and whether existing known concerns are now worthy of addressing.

We agree that in general the market frameworks are resilient, and will continue to operate effectively through most of the changes envisaged. The framework also provides a mechanism for incremental changes in market design as required. AEMO will contribute to the evolution of the market as appropriate to ensure efficient operation in the future. The AEMC has contributed to further improvement by recognising and proposing ways forward in a number of important areas, particularly in relation to electricity networks. AEMO looks forward to further assisting with the development of the AEMC's proposals. We note that AEMC has primarily focussed upon electricity markets in this review, although gas markets are also expected to undergo profound change.

Convergence of Gas and Electricity Markets

AEMO understands the AEMC's recommendations and its expectations that AEMO will take a leadership role in the convergence of intervention rules and of market settings. At the same time, we ask that the AEMC recognise in its final report the relative state of development of the gas markets outside of Victoria and the limited extent of our powers in those markets.

Efficient Utilisation and Provision of the Electricity Networks

AEMO understands that modelling of the electricity networks undertaken for the AEMC has indicated that previous conclusions regarding the low materiality of inefficiencies relating to generator locational incentives and congestion will no longer hold. It has proposed a generator-TUOS arrangement to drive dynamic locational efficiency and a time-limited, geographically-specific congestion management regime to achieve operational efficiency with respect to dispatch congestion.

There are a great range of options available to attempt to drive these efficiencies and many variants have been tried in other electricity markets. The two options presented have been presented late in this process, and are not fully developed. They have substantial and complex economic and commercial impacts upon participants, the market operator and Network Service Providers. It will not be possible to fully investigate them and get stakeholder engagement in time for the final report to the MCE. AEMO suggests that a separate review process should be instigated to allow these options to be fully explored and alternatives considered. That review should also consider the balance of risks imposed on existing generators and potential new entrants, the tools and information available for them to manage those risks and the potential impact on the cost and timing of investment and dis-investment through any increase in their risk profile.

AEMO has nevertheless provided preliminary comments in relation to both options, particularly with respect to the responsibilities that we expect we would inherit with these schemes. In respect to generator transmission charges (G-TUOS), AEMO would be expected to have a major role in setting Victorian tariffs, and the NTP may have a role in the national process for all regions. For congestion management, we would expect to carry responsibility for implementing and operating the scheme.

We have also made some high level comments on the likely efficacy of the schemes in terms of achieving their intent with respect to our understanding of the drivers of participant and NSP behaviours.

Connecting Remote Generation

AEMO appreciates the AEMC's development of this model for centrally planned joint connection assets, and we have contributed in the stakeholder groups to date. We have raised a number of issues that we can observe from our unique perspective. Perhaps the most significant is the interaction between the development of these extensions and the development of the shared network. If the network is not able to be developed holistically, consistent with the National Transmission Network Development Plan, then a sub-optimal outcome is likely to result.

With respect to the proposed role of the National Transmission Planner in the new regime, at a high level we are comfortable with the developments to date. We have made some minor suggestions and will comment further as the details develop.

Inter-Regional TUOS

AEMO supports the AEMC's recognition of this issue and its attempts to address it. We have listed some implementation challenges in the proposed model that the AEMC may not have recognised. We have also listed some further options for investigation and indicate a preference for the eventual development of a consistent, national TUOS regime.

Retail Issues

The AEMC has heavily focussed upon matters associated with retail price caps in its review. This is not AEMO's area of expertise, but we express our concern that matters in the prudential frameworks of electricity and gas markets, in particular arrangements to accommodate the failure of a large retailer, continue to carry significant risks. These matters have not been properly addressed to date in Australian energy markets and should be prior to the introduction of the Carbon Pollution Reduction Scheme.

Generation Capacity in the Short-Term

AEMO welcomes the AEMC's consideration of additional mechanisms to provide greater surety of electricity market reliability. Our key concern is to ensure that there is a single, well structured and coherent set of arrangements. Adding additional incremental mechanisms without rationalising existing arrangements adds market complexity and operational burden at stressful times. We discuss the Load-Shedding mechanism option proposed by the AEMC, which we recognise to have potential advantages as well as challenges. We however request that this mechanism not be promoted concurrently with the short-term Reliability and Reserve Trader mechanism but potentially considered as a replacement when the current provisions expire.

AEMO welcomes AEMC's interest in promoting improvements to the reporting of demand-side capability and recommends that an industry working group develop practical ways of obtaining this information.

System Operation with intermittent generation

AEMO largely supports the recommendations of this chapter which conclude that existing frameworks are capable of adapting the market mechanisms to ensure a secure and efficient system. These frameworks imply a leadership role for AEMO in identifying areas of risk and proposing, along with industry, market-based solutions to them. AEMO understands that expectation and an example is already underway in terms of formal arrangements for inertia in Tasmania. Furthermore, AEMO is re-starting its Network Support and Control Services review.

For ease of reading, the division and sequencing of issues in this submission aligns with the AEMC's draft report. It should not be taken as representing AEMO's view as to the appropriate division or relative importance of issues.

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1. Connecting Remote Generation

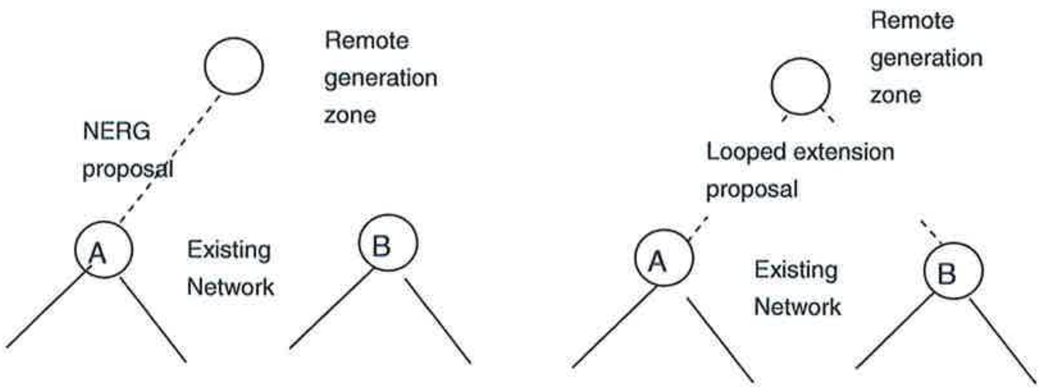
AEMO, through its predecessor organisations: AEMO(T), VENCorp, NEMMCO and ESIPC, has participated in the Stakeholder Advisory Committee and the detailed working group into this matter. Many stakeholders clearly hold the view that the current regulatory regime will fail to develop efficiently sized extensions to regions of prospective generation especially where those are potential new generation regions remote from the grid. We therefore welcome the AEMC's investigations into this challenging area and its development of a model (the Network Expansion for Remote Generation, or "NERG" model) for discussion. The comments below are a result of AEMO's current considerations of that model.

Our comments result from considering the objective of the efficient development of the transmission system. We believe we can contribute to the design and operation of the scheme thanks to our national planning perspective and also due to our detailed Victorian transmission planning role.

1.1 The distinction of connection assets versus shared assets

The draft report has relied heavily upon a simplified fully radial representation of a hypothetical extension to a remote network hub. The extension is efficiently sized for the prospective individually connecting generators, who fund and receive effective specified property rights over it whilst the extension has no impact on the existing network. Realistic scenarios are of course much more complex, and efficient network extensions are often neither radial nor remote. The concept of an efficient size of the asset is also not simple when one considers the potential for an initial investment with an upgrade strategy or where multiple intermittent generation plans to use the connection

It is therefore important to consider situations where a network extension may provide both shared and connection benefits. By separating the concepts, there is a risk that the optimal augmentation planning will not occur. Consider the following scenario.



NERG cost: $50m. No broader market benefits.

Extension cost: $80m, but provides $40m of shared market benefits or avoids $40m of reliability investment to point B

Draft

Arguably this problem already exists in the current regime, with connecting parties seeing no private advantage in exploring alternatives to the lowest cost connection which would provide shared benefits. However the issue is likely to be more significant with the larger augmentations that would be expected with a NERG. Furthermore, the role of the NSP's in the design of the NERG, unlike a normal connection asset, provides an opportunity to achieve this more efficient planning.

An example of an attempt to capture both broader public and private benefits for an augmentation is provided on AEMO's website: Victorian Electricity Transmission Network Connection Augmentation Guidelines, March 2007. Section 4.3 of these Guidelines describes a process where the TNSP can explore incremental additions to a connection augmentation, funded by customers.

1.1.1 NERG impact on shared network

The report mentions that Annual Planning Reviews should include the possible implications for the shared network in relation to each NERG zone. This could be interpreted to mean that in planning for the NERG the implications for the shared network should be considered:

- only to the extent that the level of shared network congestion would invalidate the generation projects; or
- in a "deep" manner, where a proposed NERG project is considered in a more holistic framework, including the broader network wide impacts of introducing generators to that point on the shared network, for example evaluating the cost of any resulting increased congestion on existing generation.

It is our understanding that the former is intended as that is most similar to the investment decision taken by discrete connecting generators. In this case, an assessment would still need to be made of the level of congestion generators connecting at the NERG were likely to experience to ensure that connecting was likely to be commercially viable. Undertaking the narrow assessment also implies accepting that the most efficient proposal, considering the network as a whole, may not be promoted.

In any case, the matter should be clarified to assist NSP planning and avoid dispute.

1.1.2 Changes to Future Use

Compared to discrete connection assets NERGs are more likely to be useful for future developments of a shared nature, e.g. through looping or through the connection of remote load. Even where the initial connection is radial, the potential should be maintained for the augmentation to be considered in the longer term, as part of the overall development of the network to service customers and transfer power as well as to connect additional generators. The AEMC proposes doing this in a manner consistent with the existing framework but that framework may not be entirely clear for these assets. It is important to clarify how NERGs will be treated to ensure:

- Such efficient options to enhance the network can be seamlessly explored by the NSP;
- The resulting impacts on generator connection costs and access do not undermine the locational efficiencies intended by the funding arrangements; and
- There is a low risk of disputation in relation to the resulting impacts on generator costs and access.

1.2 Expansion

When designing the NERG, it may be that the optimal approach would be to build to an initially limited size but to also provide a capability to substantially expand the NERG at a later date. An example is where a line is built to a high voltage capability but is initially energised at a lower voltage or where a line is initially constructed with one circuit but with provision to be upgraded to a double circuit.

We note the discussion of further expansion opportunities in Appendix F, and suggest the AEMC ensure such an approach is accommodated as more detailed development of the NERG framework occurs. Approaches of this manner are not only economically efficient but they defer some of the expenditure and allow time for further development needs to become clearer.

1.3 Joint Planning

Where a NERG has implications beyond a single NSP, the AEMC recommends a shared planning approach. The outcome of this could then be shared ownership of assets associated with NERGS and ongoing need for coordination of decisions relating to those assets. Decisions will be required on the allocation of customer recovery of underutilisation in these instances. There may also be implications in relation to inter-regional TUOS.

1.4 Connecting Capacity and Access Rights

The AEMC has described a process where the system normal capacity of the NERG should be assessed up front and that only this amount of connection capacity will be made available for subscription. Section 1.2 above notes that the optimal approach may often be to design a connection which has upgrade potential and hence the process to set the ultimate capacity may need to reflect these possibilities. In practical terms, the potential range of upgrades available, including the use of dynamic ratings, mean that the physical capacity of a system is not necessarily easy or desirable to fix at an early stage. The potential benefits of allowing some flexibility in the use of capacity is discussed in section 1.4.2 below. When these considerations are taken into account, alternative approaches to define the measure of access offered to a subscriber to a NERG may be found to be warranted.

1.4.1 Dispatch constraints

The subscription presents a form of right, noting the AEMC makes it clear this does not represent any right of access to the existing network. Whilst considering these "rights", potential NERG users must keep some important issues in mind:

- When developing dispatch constraints, AEMO will not distinguish between the regulatory classification of the assets it is attempting to protect. The dispatch engine will simply select the most efficient, i.e. cheapest dispatch solution considering the generator offers presented and their impact on those assets.
- When AEMO applies a constraint within the dispatch engine to protect the network, it is often difficult for a participant to distinguish exactly what assets the constraint is protecting.
- Some constraints are likely to be affected by both shared network assets and NERGs. For example, the form and operation of existing stability constraints will be affected by the presence of the NERG.

1.4.2 Varying Access Requirements

In contemplating the process of subscription, it may be useful to provide some flexibility in relation to the contracting of capacity. Some generators need a high degree of access capacity at peak demand times to justify their investment, whilst intermittent generation might comfortably accept a degree of congestion in return for the ability to connect more capacity.

Were this to be allowed, a compensation arrangement between NERG users outside of the dispatch process may be required.

1.4.3 Subscription Process

Appendix F provides some useful descriptions of how the standard connection, negotiation for variation and opportunity for upgrades may occur. Matters for further development include:

- Timing rules to enable generators to plan their investments whilst delaying contract execution until they have committed;
- Efficient ways to manage over-subscription, e.g. auctions;
- Transferability of connection.

1.5 Obligations upon new connectors to participate in a NERG

A question for clarification is whether a generator will be permitted to bypass a nearby existing NERG in favour of direct connection to the grid in a manner that is not economically optimal. It is possible that some connection alternatives in the area may have lower connection costs, provide easier access or be available sooner.

1.6 Role of the National Transmission Planner (NTP)

AEMO understands that the NTP has been allocated a key role in NERG development. This is a new challenge for the NTP, which is otherwise focussed on providing information without a direct linkage to investment approval. The described role for the NTP, as we understand it is an advisory function of providing advice to NSP's and then the AER, but not making a decision of itself. This is consistent with the regulatory framework and roles of the NTP. We are unable to comment on any specifics of the risks to AEMO until draft rules are developed.

In relation to our general informational provision role, we would like to note that regardless of the development of a NERG regime, it is our intention to try to develop in the short-term an addition to the NTNDP: a high-level exploration of options for remote network extensions. We intend to provide initial estimates of the cost of variously sized major line extensions into areas substantially remote from the main network that have had public discussion as possible locations of future generation. This will complement planning of the development of the existing shared network and is intended to provide an early indication to generator developers as to what locations may realistically be connected at some future time and therefore enable the developers to focus their exploration.

Developing this capability will require the expert assistance of TNSP's, and at this stage we have not yet formally approached them to confirm their involvement.

1.6.1 Forecasting Prospective Generation Zones

AEMO understands the role that the AEMC wishes it to fulfil with respect to identifying zones that are worthy of deeper investigation as having potential justification for a NERG. In considering taking such a role, we note the following uncertainties and issues that the task implies:

- Long-term generation forecasts by their nature are somewhat speculative given the actual generation investment will be driven by many factors including technological developments in all forms of generation and carbon reduction, fuel and resource costs and government policy.
- The NTNDP approach is designed to provide a number of possible scenarios of development reflecting the uncertainty and possibilities. The zoning role however implies that AEMO will need to prepare a specific ranking of the most prospective zones. It is quite likely that the ranking may differ significantly between scenarios and change from year to year as new information comes to hand.
- The approach as recommended by Allens Consulting as part of the 1st interim report for recognising the value of renewable energy certificates within an economic transmission assessment implies a "quota" approach to the development of renewable

energy. This implies that where two NERG's of similar prospectivity emerge, it may be that either but not both can be justified as providing a cost effective option for meeting the expanded Renewable Energy Target. An assessment of those options which represent superior value as sources of renewable energy, requires consideration of the full inventory of renewable energy sources in Australia and their expected costs.

- When modelling using the Allens approach, the NTP may come to the view that the renewable quota can most efficiently be met through generators connecting in close proximity to the existing network. Parties should be aware that it is therefore possible that few or no zones will be recommended for construction.

1.6.2 Verifying generator connection assumptions

AEMO considers that it is in a position to provide a relevant view to the AER on the credibility of generator connection forecasts regarding a NERG plan. A potentially important source of information in seeking to verify generation connection assumptions will be connection enquires received by TNSP's. In some cases this information will be held in confidence by the TNSPs and hence will not necessarily be available to AEMO. Consideration should be given to the need for a specific obligation to provide that information.

AEMO might also be able to provide a view on the consistency of the NERG to the NTNDP. It would also need to be considered whether the AER should, when approving a NERG, to consider its consistency with the NTNDP. The best way to achieve these is perhaps not to obligate a role for the AEMO, but to require the AER to have regard to input, if provided, by AEMO. This is consistent with the NTP's role in the RIT-T.

A key question to consider in presenting rules is whether the AER, should consider the consistency of a proposed NERG with the NTNDP as a relevant factor in assessing its approval.

1.7 Role of AEMO's Victorian Transmission Planner

It is our understanding that by defining the NERG as a connection augmentation, the planning and development of a Victorian NERG will not be carried out by AEMO as part of its Victorian TNSP function but by SPAusnet. We advise this for clarification only such that the AEMC can confirm that it is the intended outcome.

1.8 Contestable provision model

AEMO supports further development of the option for contestable provision of the NERG, noting that contestability of transmission asset provision has had some demonstrated success in Victoria. Issues to be resolved include identifying which party will perform the detailed planning of the NERG, who will manage the tendering and contracting and who will be responsible for collecting customer funds during the period of underutilisation.

1.9 Role of the Network Extension for Remote Generation (NERG) in the network planning framework

AEMO expects that there will be differing views on whether the addition of the concept of NERG's into the existing network planning framework is necessary to ensure efficient expansion of the network. While network extension to new generation zones is feasible under the current regime, there are a range of views as to its adequacy. In the above discussion we have considered some of the complexities that a NERG model will introduce, such as boundary matters between the NERG and shared assets and the ability for one planner to consider the connection and shared services in the one study that need to be balanced against the benefits of a regime designed specifically for collective connections.

Given these uncertainties, it may be worthwhile considering a compromise to continue development of the NERG model but to either:

- Apply a sunset to the model;
- Set a clear review process that would consider whether the arrangements remain justified; or
- Activate the NERG as a "last resort" planning model only, perhaps where a connecting generator was to convince a regulator of an instance of planning failure.

1.10 Interaction with G TUOS regime

We understand the motivation for the NERG regime is an attempt to marry the economy of scale benefits of centralised planning whilst retaining the locational incentives of self funded connection assets. In section 2.1 below we discuss the Generator TUOS scheme. We understand that the G TUOS charge would be intended to recover only the LRMC of network downstream of the NERG.

An alternative to the NERG model worth considering is to allow these new assets to be classed as shared assets but, by using relatively small GTUOS charging zones that can identify the assets being developed for a NERG, to achieve locational incentives of generators connecting to the extension. If this permits the network extension to be classified as shared, then there should be less risk that the extension will not be fully integrated within the overall network plan.

2. Efficient Utilisation and provision of the electricity network

AEMO understands the analysis presented with the 2nd interim report that has lead to the findings that climate change policies will drive:

- A more rapid period of investment and retirements in the generation sector, such that the dynamic efficiency implications of locational incentives will be more material than they have been to date in the NEM; and
- Greater dispatch congestion within NEM regions, particularly in proximity to intermittent renewable generators, such that the operational efficiency implications of the regional pricing model will become more material.

In recognition of this, the AEMC has presented two proposals to address these respective conclusions. The two schemes have significant and complex implications to AEMO, TNSP's and participants. They have been suggested at a late stage of the review and have not been presented in detail. It will therefore be impractical for stakeholders to adequately engage such that the AEMC can confidently present preferred models to the MCE by September 2009. We suggest instead that new review processes begin to respond adequately to the findings and that these processes should have the capacity to consider these schemes against other options. This review should also consider the aggregate risks imposed on generators and the methods available to them to manage those risks. The risk profile of generation investments will naturally affect the cost of capital for those investments and any increase in risk without compensating mechanisms to assist parties manage those risks could delay investment or accelerate retirements.

The following comments are an initial list of matters recognised by AEMO that will need to be considered as the models are developed.

AEMO also notes that the analysis has only considered efficient utilisation of the electricity network. AEMO would prefer that analysis was also carried out on the provision and utilisation of gas networks, at a time of possibly even greater change to gas markets.

2.1 Generator TUOS Scheme

AEMO notes the AEMC's attempts to drive dynamic efficiency in the locational decision of new generators, and to provide a locational incentive in relation to retirements. The G-TUOS scheme has promising aspects and we note it has been used with some success in parts of Europe. Inevitably it raises a number of difficult issues, some of which are unique to the NEM. Below are some initial observations of these. AEMO believes it has relevant expertise to assist the AEMC's understanding of these issues, and would be very happy to engage further.

2.1.1 Nature of Calculation

The model proposes that G-TUOS tariffs will be calculated from a forward looking estimate of the Long-Run-Marginal-Cost (LRMC) of new transmission to accommodate new generation in a particular NEM zone. This would require a detailed network development plan going well into the future, ideally over the full asset life cycle interlinked with a demand and generator forecast. LRMC is then calculated by marginally adjusting the forecast generation in a zone and observing a resultant change in the cost of the optimal network development plan.

At a high level such an approach may appear feasible because network planners already produce Annual Planning Reports (APR) and the National Transmission Statement (NTS) that attempt to present an economically optimal network plan. However G-TUOS will create some new paradigms for Australian networks:

- The APRs and NTNDP are indicative forecasts only containing unavoidable uncertainty about long-term generation development. They have a useful role in the provision of information to investors, but assets are not committed until a more detailed regulatory investment test is carried out, shortly before construction. In contrast, G-TUOS will drive direct financial outcomes.
- The APRs and NTS are not presently performed in sufficient detail to enable the LRMC to be adequately calculated. The plan used for G-TUOS would need to ensure that it was:
    - Adequately detailed, capturing all the likely shared network augmentations, replacements and retirements that were likely in the period for each study case, including relatively small projects;
    - Adequately costed, in that a defensible estimate of each of these augmentations is provided; and
    - Adequately timed, in that a specific time in the future is chosen for each augmentation.
- The incidence of tariff calculation for network users presently uses historical data regarding peak loads and actual asset values and can be prepared mechanically. In contrast, G-TUOS will be based on forward looking data.

2.1.2 Breadth of Assessment

Customer transmission tariff calculations are presently performed by TNSP's using intra-state data only. The 2nd interim report does not discuss whether the G-TUOS is to adopt a similar approach or attempt to perform the calculation NEM-wide.

We note the following issues supporting the potential need for a TNSP to take a relatively broad perspective:

- The nature of generation forecasting implies that a national perspective must be taken to it, e.g. a key driver for new generation will be delivery of the national Renewable Energy Target at lowest cost.
- Incremental generation changes in any one zone will affect the optimal transmission plan in other zones and across state borders.
- If G-TUOS is calculated using a national approach, it may have unintended interactions with inter-regional TUOS.

2.1.3 Who will perform the calculation?

Identifying the party best capable of holding the responsibility for such calculations is also challenging. TNSP's are familiar with detailed tariff calculation but may not be equipped to approach it with a national focus. On the other hand, the NTP does not perform network planning at a level of detail to allow it to accurately calculate G-TUOS.

2.1.4 Revenue Neutrality

The report explores an option of making the scheme revenue neutral across generators. We observe that because the great majority of NEM generation is located in "generation-rich" zones, we would expect a G-TUOS scheme naturally to be strongly revenue positive. A normalisation process is therefore likely to undermine the intent of the scheme by either recovering less than efficient charges from generators in generation rich zones or over-paying generators in load-rich zones. Revenue neutrality applied on a state by state basis may also have implications for the relativity of charges to generators in one state compared to their competitors in another.

2.1.5 Zones

The report has recognised that selection of the zones will be a critical and contentious issue. The intent of the scheme would be undermined if the zones were too large. For example, were they to include both a generation and load centre the G-TUOS tariff could well be zero.

The report has proposed by way of example the use of the NTS zones. Note that NTS zones were not intended for this purpose and AEMO cannot commit to providing stability in their boundaries as this would inappropriately constrain the framework used for planning

2.1.6 Capacity of generator

It is proposed that G-TUOS would be levied by the capacity of the generator regardless of whether it is a "peaking" or "base-load" generator. We understand the motivation for this, because at the peak demand times for which the network is designed, all these generators will attempt to use the network. However we highlight that capacity may have different implications for some technologies. Wind generation typically can achieve an availability factor of only around 30%, and its use of the network at peak demand time has been shown to be less than this. It is also to be expected that the network will not be economically planned to accommodate the full theoretical output of wind at all times. It therefore may be incorrect to levy wind generators on the same per capacity basis as other generators.

Note that registered capacities have been provided to AEMO by participants to meet the existing Rules requirements. They have not been subject to detailed verification as there are only minor financial implications arising from them.

2.1.7 Distribution connected generators

Many generators are connected directly to distribution networks, some of which are quite large. It is not clarified, but presumably the G-TUOS scheme would apply equally to embedded generators as to transmission generators. An approach may be able to be developed which would enable the removal of avoided TUOS payment arrangements to embedded generators by integrating them into the one price signal.

2.1.8 Customer/Load boundary issues

Where customer network charges are asymmetrical to generator charges, it is possible to have perverse incentives where load and generation is in proximity. This is already the case and can lead to participants inefficiently bypassing the network. A G-TUOS scheme may lessen this incentive, but only if the charging is approximately symmetrical. This doesn't appear to be the case in the proposed model.

2.2 Negotiated Financial Access

AEMO welcomes the AEMC's views on the current drafting of rule 5.4A. As the AEMC has noted AEMO is presently undertaking a review to ascertain whether, in its capacity as the provider of shared network services in Victoria, it is able to develop a workable generator compensation scheme in accordance with the Rules and within an 'open access' framework.

While the review and negotiations with the generators are continuing, AEMO's initial views are that the present drafting of rule 5.4A has led to confusion and an inability to develop a generator compensation scheme within a generator connection framework without considering broader market design issues.

AEMO remains committed to work with all participants connected to the Victorian shared transmission network to ascertain whether a scheme can be devised which achieves the NEM objective. However, this work still has some way to go. AEMO believes that its work can continue even if those elements of rule 5.4A contemplating generator compensation are removed and there may be some benefits in removing the provisions such that the present drafting does not constrain the development of any broader market based scheme. Should it be successful in developing a scheme which has the support of the market and meets the NEM objective, AEMO would propose amendments to the NER at that time.

The AEMC has also asked whether there are other elements of rule 5.4A which need to be retained. As the AEMC is aware, in addition to the generator compensation scheme rule 5.4A establishes the link to negotiated transmission services arising from negotiations between NSPs and connection applicants. AEMO believes that these elements must remain, whether in its current form or be incorporated into the substantive elements of rule 5.3.

2.3 Congestion Management Scheme

AEMO understands that the AEMC's motivation for exploring a congestion management scheme is that the incidence of congestion within NEM pricing regions could increase, above earlier expectations, as a result of generation investment encouraged by climate change initiatives, and that the proposed G-TUOS scheme is unlikely to address any emergent operational efficiency or dispatch related implications of such congestion. There is limited detail in the report regarding the proposed scheme, but we note that it has similar high-level design features as the "Constraint Support Contracting/Constraint Support Pricing" (CSC/CSP) model that was proposed by the MCE in 2003. AEMO suggests that the AEMC should use the material produced by the MCE as a starting point for this investigation.

The following comments are based around our expectation that this is the model that the AEMC is considering and our experience from that development.

2.3.1 Snowy CSC/CSP Trial Experience

From 2005-2007 NEMMCO implemented a "trial" of the CSC/CSP concept within the Snowy region. The region had experienced a significant amount of congestion occurring on two lines between two large and price responsive generating centres owned by a single generator participant. This location was electrically less complex than some other locations of historical congestion, such as South Western Qld.

The trial rule obliged NEMMCO to identify constraint equations that directly controlled the flow through those lines, calculate shadow nodal prices for affected generators, and to transfer settlement money between the inter-regional residues and the participant according to formulae related to the marginal values and relevant generator coefficients of these constraint equations. Approximately 120 constraint equations were identified.

The trial successfully demonstrated the feasibility of the scheme in that circumstance. There are nevertheless some learnings from the trial, and some unique features of the situation that should be kept in mind. These are:

- Identifying which constraint equations should be tagged as being within the scheme required some interpretation. Constraint equations are being regularly developed and altered, and there was a risk of inconsistent interpretation, especially when constraint equations are developed close to real-time.
- The Snowy trial transferred residues according to the marginal value of constraint equations. These equations included Snowy Hydro and other generator terms, but only diverted an amount consistent with the difference between regional and constraint support pricing of the Snowy generator outputs. Other generator terms existed in these equations but were not subject to the adjustments.

- Congestion from other constraint equations can still affect the included generators without triggering the adjustments. Generators can be surprised by which constraint equations are included and which are excluded. For more complex arrangements, the challenges of maintaining the list would be greater.
- CSC shares were administratively allocated by Snowy as proponent of the trial, and agreed through consultation. The only other affected "participant" in the scheme was the inter-regional settlement residue (IRSR). The diffuse nature of the IRSR beneficiaries probably resulted in this allocation being of lesser controversy than a situation where multiple generators are involved.
- No auctioning of CSC shares was required.
- NEMMCO was able to develop systems to operate the trial in about 9 months. As they were intended to be short-lived, these systems were not built to market systems IT standards nor subjected to the usual level of change controls. Future systems would have to conform to the routine system development release timeframe and considerably longer implementation would be expected. However, were AEMO to invest in a generic capability, subsequent applications could potentially be implemented more quickly. This would however require stability in the generic design.

2.3.2 Constraint equations or geographical assets?

When considering the application of congestion management schemes it is important to recognise the nature of the "hub and spoke" representation of the network in the dispatch engine and the use of fully co-optimised constraint equations.

The protection of network elements usually requires constraint equations to be built with numerous controllable variables represented, and, where any looping is present, a wide range of co-efficient values. The protection of one element usually requires building multiple constraint equations, to manage a range of power system contingencies, and to prepare for prior outage conditions. The variables represented and the ratios of their coefficients can be quite different in each constraint equation.

Some real examples of these situations are:

- The co-efficient on the Shoalhaven generator to manage loading on the Yass-Canberra line against the contingent loss of the Kangaroo Valley to Dapto line is approximately unity. However it's co-efficient for the constraint equation managing loading on the same line against the loss of the Kangaroo Valley to Capital line is close to zero.
- The co-efficient on the Eraring units 1&2 to protect the Liddell to Newcastle line is -0.511. With the prior outage of both Bayswater to Sydney West lines, to protect the Liddell to Newcastle line against the contingent loss of the Bayswater to Wallerawang line, the coefficient is -0.1618.

When stakeholders consider a point of congestion, they usually intend to refer to congestion across a collection of network paths, often described as a cutset, rather than any single network asset. Thus it is expected that any practical application of a geographically limited congestion management scheme will require numerous constraint equations to be tagged as being part of the scheme. Within that collection of constraint equations, there will be a range of coefficients for each dispatchable variable.

As demonstrated by the Snowy trial, the selection of the tagged constraint equations will require some judgement, which may need to occur in operational conditions. This is particularly the case where the network protection is of a voltage or stability nature and it is difficult to define a precise location.

The likely variation between the coefficients of generators in the tagged constraint equations will make it difficult for participants to predict the amount of settlement adjustment that their generator will receive, and therefore difficult to determine the appropriate quantity of CSC required for risk management. This presents challenges for participants in determining what quantity they should bid for at auction.

2.3.3 Settlement Balance

While most constraints in such a scheme would result in positive residues, it was recognised in the 2003 work that, this is not always the case. In some cases, the schemes may not be self-funding unless holders of CSC were obligated to contribute. It is not clear how this would operate within an auctioned regime.

2.3.4 Auctioning Issues

The report indicates a preference for auctioning of residues. AEMO operates the IRSR auctioning process on a very stable set of regional boundaries, and notes the following relevant issues:

- Financial laws require various legal and probity obligations, including most likely, the provision of an information memorandum. This requires several months of preparation and detailed annual review.
- Participants indicate a preference for choice: a range of future quarters offered at each auction and spatially and temporally linked-bids. This is achievable for the IRSR auctions only due to the stability of the region boundaries and would be difficult and complex if used for targeted, time-limited congestion schemes.
- As per the IRSR auction, issues associated with authorised participants, prudentials and participant suspension will need to be addressed.

2.3.5 Triggers

As discussed in the report, as the scheme is location specific and time limited, it will need a robust mechanism to trigger the creation and removal of schemes through some estimate of the economic cost of inefficient dispatch in the presence of congestion. Historical review processes such as the mispricing analysis for the interim Congestion Information Resource might be used for this. Note however:

- The mispricing analysis indicates the correct locational price, but not the depth of the congestion which would be needed to assess the full economic cost of mispricing. An assessment of the full economic cost of historical mispricing would probably require a hypothetical dispatch re-run.
- The mispricing analysis assesses the marginal value of binding constraints which assesses the cost of congestion against generator offers as presented to the dispatch algorithm. This may not reflect the true marginal economic value of more efficient dispatch, especially where congested generators offer at the market floor price to maximise volume or where competing congested generators have similar technologies and therefore marginal cost.
- Mispricing does not necessarily mean inefficient dispatch. For example, where a single generator is constrained off by congestion on a radial line, dispatch will be fully efficient despite the generator being mispriced.

Consideration would need to be given as to whether congestion resulting from historical outage conditions should be excluded in the analysis.

A historical analysis of congestion may be a poor indicator of future congestion, especially where merit orders change as a result of Carbon prices reaching a particular threshold or where new generators connect. A forward-looking prediction will, however, require assumptions that are difficult to justify. AEMO concurs with the AEMC's desire to make the contentious decision to trigger a scheme as mechanical as possible. However a degree of judgement appears inevitable when selecting the relevant cutset as discussed in 2.3.2.

In addition to the potential difficulties to AEMO, we recognise that the process to trigger such a scheme would need to be as predictable as possible for market participants. The desirability for a notification period prior to introducing such a scheme on a zone should also be considered. As important as the trigger to commence such a scheme would be the mechanism to remove such a scheme at some time in the future. Again this process would need to be as clear and predictable as possible.

2.3.6 Alternative to targeted, auctioned scheme

AEMO notes that these challenges arise mainly because the suggested mechanism is:

- Location Specific;
- Time limited; and
- Auctioned.

An alternative that deserves consideration is the proposal presented in some submissions which applies congestion pricing generally but for each binding constraint equation allocates residues in proportion to the product of each term's coefficients and offered availability[1]. Such a scheme appears to allocate residues roughly in accordance to what each generator or IRSR rights holder would need for risk management for that constraint equation and meets the AEMC's objective of treating all presented capacity equally. The scheme avoids auctioning and requires a mechanical adjustment to settlements only and therefore avoids the need for market operator judgement.

It may also be possible to apply such a scheme in a time-limited, specific manner, although that would retain the issues associated with triggering and the selection of active constraint equations.

2.4 Firming of Inter-Regional Settlement Residue

The report seeks views on whether schemes should be investigated which provide greater firmness for IRSR. This matter has been considered in some detail previously, in the 2002 COAG Review of the Australian Energy Markets (Parer Review) and the 2006 Energy Reform Implementation Group (ERIG). The objective for such a mechanism is to provide more support for inter-regional hedging and therefore greater competition in the hedge markets. The linkage to climate change policy per se is not clear.

The best way to provide more certainty of IRSR as a hedging mechanism is to seek ways to improve the physical reliability of the network and to encourage efficient congestion management for constraint equations that include interconnectors. Any schemes that result in a divergence between the physical power system reliability and the hedge market's "financial reliability" may lead to:

- a net deficit of settlement residues, for which funding arrangements would need to be determined; and
- distorted investment incentives, as externally supported hedging may be more attractive for risk management than procuring physical supply.

2.5 The 5 minute /30 minute Anomaly

The AEMC has concluded that the 5 minute pricing/30 minute settlement anomaly between dispatch and trading intervals in the market may present a barrier to investment to generation that can respond to variations caused by intermittent generation. However the AEMC also decided that the cost of converting to 5 minute settlement would be prohibitive.

Other alternative remedies are possible which would have different cost outcomes. In its submission to the 1st interim report, NEMMCO provided material from a 2002 investigation

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[1] Or in the case of interconnector terms, an implied availability derived from the next non-binding constraint.

into an alternative: "Simulated 5 minute settlement". This maintained the 30 minute settlement cycle, but applied an adjustment to all participants where 5 minute data is available[2]. Loads without 5-minute data are not obligated to implement additional metering, but are subject to a whole of NEM adjustment. At the time, NEMMCO estimated its own costs of implementing such a scheme as a $1-$2 million.

2.6 Variability of static loss factors

AEMO supports the draft report's conclusion in relation to static loss factors.

[2] All scheduled, semi-scheduled generators and some large loads provide enough data to resolve a 5 minute estimate of metered consumption from their half hourly metering.

3. Inter-Regional Transmission Charging

AEMO supports a regime that promotes the efficient allocation of network costs to those who benefit from their use. AEMO agrees that the load export charge arrangement would be a good first step towards developing a national regime. However, in the long-run, AEMO considers that a national transmission pricing arrangement is the best option and will complement future efficiency reforms for the NEM. AEMO suggests an appropriate place for the AEMC to consider how this could be achieved would be as part of its investigations into a G-TUOS regime.

Should the AEMC proceed to develop an inter-regional arrangement ahead of the G-TUOS regime, its proposed design for the load export charging arrangements presents a number of practical challenges that need to be considered:

- Consistent pricing arrangements may need to be introduced into the NER to ensure consistency of application across the NEM. Under the current arrangements for network pricing all TNSPs are now required to develop a pricing methodology consistent only with the principles set out in the NER and the AER's pricing guidelines. This has resulted in some differences in pricing arrangements and may create some distortions when attempting to transfer an actual tariff between regions. For example, some TNSP's recover 50% of their shared costs through locational peak charging, whilst others effectively recover 100% through energy charging.

- There may be an inconsistency in the arrangements between pricing within a region and pricing between regions. The Victorian peak-based pricing is done reflective of geographical consumption on the 10 peak demand days, to reflect those times that the network would need to be augmented. However, this may not be appropriate for a load export charge. For example, on the top ten Victorian peak days energy flows along interconnectors are typically towards Victoria.

- Issues regarding co-ordinating TNSP's would need to be considered in relation to regions that do not align with a TNSP boundary;

- Consideration of whether alternate arrangements are required for MNSP interconnectors.

A process is required that is accurate and fair, but also practical and does not create an excessive step change. Suggestions worthy of investigation include:

- Transferring only the flat energy-based component of TUOS;

- Calculating inter-regional TUOS tariff based only upon new investments brought about since the new climate change policies have become significant rather than historical assets.

4. Retail Issues

Within this line of activity, the AEMC has primarily focussed upon retail price caps and the resulting financial market risks imposed upon retailers. Retailer financial risks will in turn affect generators as a result of hedging, and potentially through short-payment of AEMO settlement. Thus AEMO supports AEMC's concerns in relation to this issue.

4.1 Prudential framework and robustness of Retailer of Last Resort (RoLR) arrangements

We note the AEMC has considered the robustness of the retailer of last resort (RoLR) mechanism given that it may be tested if the additional costs arising from the CPRS result in retailer distress, failure or exit from the market. Due to work already in train under the MCE, the AEMC further considers that "no additional process appears warranted at this stage". The section then concludes that it is essential that the MCE processes for revised RoLR arrangements progress to resolution prior to the commencement of the CPRS.

AEMO suggests that the conclusions reached by the AEMC in this regard warrant further consideration to draw out the risks involved and address them. We suggest that development of a national RoLR arrangement is clearly a frameworks level consideration, and is therefore within scope of the review. While a process is in train at present to develop a new regime, it is not clear whether it will be ready in time for the start of the CPRS. Meanwhile, current jurisdictional arrangements are often not sufficiently developed to cover the failure of a significant second tier retailer or first tier retailer.

In view of the conclusion reached by the AEMC in the 2nd Interim report, it is important that the AEMC consider the likelihood of adequate mechanisms being in place prior to CPRS commencement. We note that there is likely to be a significant implementation task to be carried out by both industry and AEMO prior to any new scheme becoming operationally ready. The time required for such implementation is not considered in the AEMC's assessment, and when factored in alongside the current rate of development of the scheme, there would appear to be a material risk of the AEMC's readiness condition not being met.

It would therefore be appropriate for the AEMC to evaluate further the issues surrounding RoLR with a view to clarifying whether accelerated development of the national scheme, or further development of the current jurisdictional schemes is necessary, and making appropriate formal recommendations if warranted. Given the risks identified in the report, this would appear to be a material consideration for the AEMC to clarify.

5. Generation Capacity in the Short-term

AEMO welcomes the AEMC's consideration of enhanced arrangements for the provision of additional electricity reliability in the rare circumstances where the market fails to provide it. A number of arrangements already exist in this area, and by their nature tend to be used only very occasionally and at the most stressful times for the market operator and participants. It is important that these arrangements are always considered as a whole, to ensure their consistency and to strive for operational simplicity. Complexity causes confusion for operators and participants, thereby increasing market risk.

The existing non-market arrangements that can be used to secure reliability include:

- The Reliability and Reserve Trader (RERT);
- Mandatory Restriction Pricing;
- Directions to scheduled participants;
- Instructions to non-scheduled participants including NSP's;
- Intervention Pricing.

The processes to activate and use each of these are complex. It is likely that in stressful power system conditions, combinations of the above will need to be operated at the same time.

5.1 Short-notice reserve contracting

AEMO is participating in the Reliability Panel's development of changes to the RERT, which includes a capability for shorter-notice contracting. It is expected that a rule change will soon be proposed by the Panel along with the provision of new RERT guidelines. If made, AEMO will have to subsequently amend its own procedure and implement a panel arrangement. This is likely to be completed before the end of 2009.

5.2 Load-Shedding Management (LSM) Scheme

AEMO notes the suggestion of an LSM scheme as described in Appendix H. Our initial observations suggest this has a number of complex benefits and issues that would require full discussion and development. There is insufficient opportunity to complete the development within this review.

The LSM activity appears to overlap with that intended by the short-term RERT. In the interest of simplicity, AEMO therefore suggests that the review should not propose the implementation of both in parallel.

Assuming the short-term RERT proposals are implemented, we suggest that LSM should be considered as a possible replacement scheme following the RERT sunset.

The benefits and issues that would need to be considered before taking the LSM further include:

- The certainty of the facilitation fee might overcome some of the challenges end-user customers have in recovering investment in demand-response capability during the period of a normal market-based customer contract;
- For some loads, interruptibility might be enabled to respond to under-frequency events as well as dispatch instruction. This could then be set to trigger at a frequency just prior to mandatory under frequency load shedding.
- Should provision be limited to demand-curtailment as suggested by the report when other technologies might provide a similar service? This could include, for example, the aggregation of small standby generators and possibly the expansion of capacity from a large generator.
- There would need to be a maximum facilitation fee set to avoid the LSM funding uneconomic options either set in the Rules or determined through jurisdictional consultation as occurs with the RERT;
- There would need to be a maximum strike price or total expected price (considering the facilitation fee, strike price and probable utilisation) either set in the Rules or agreed through jurisdictional consultation;
- There may also need to be a maximum volume recruited, per region. As the LSM would be engaged continuously, a basis for how this volume could be set would need to be found. Historical load-shedding events may be one approach;
- The arrangements for the recovery of the costs of the scheme would need to be developed. If recovered from customers, the allocation process would need to consider:
    - Arrangements for the recovery of the usage fee, which might be along similar lines to that used presently for direction and RERT; and
    - Arrangements for the recovery of facilitation fee, which could be complex if providers are spread unequally across regions.
- AEMO would need some guidance, presumably within Rule 3.8.14 as to which order LSM would be exercised at dispatch time versus other arrangements.
- Technical delivery requirements, such as availability and response time, would need to be set such that AEMO could select the best value option.
- Thought would need to be given to ensuring performance through the life of the contract and whether payment of the facilitation fee could be linked to performance.

5.3 More accurate reporting of demand-side capability

AEMO welcomes the AEMC's recognition of this on-going issue which was also recognised in the AEMC's Demand-Side-Participation Review. We concur that the current process of collecting demand-side information is affected by:

- A lack of clear obligation upon the operators of non-scheduled price-responsive activities to provide forecast information to AEMO; and
- A failure to adequately advise and recognise the probabilistic nature of some providers.

AEMO would also add that it has difficulty at times in identifying which organisation is in fact in control of these activities and therefore who should provide the information.

AEMO suggests that without further knowledge about the business environment of such activity, the introduction of a rule obligation to deliver information may be ineffective and/or oppressive. AEMO suggests first convening a working group whose constituent members represent retailers and other demand side operators. AEMO suggests it could take a leadership role as it is a key stakeholder in the outcomes such a group would be tasked to provide.

The working group would explore:

- The forms of information that can be provided at least intrusion on the obligated party; and
- The forms of information that are of most value to demand-forecasting.

AEMO hopes that this exploration would develop a mutually agreeable technical solution to address these conflicting objectives.

The constructive engagement with working group members will be responsible to deliver both:

- AEMO procedures for the provision of DSP information; and
- An AEMO sponsored rule change to unambiguously empower such procedures.

This working-group approach was used by NEMMCO in 2006 to resolve a similar issue about the quality of historical reliability information provided by large generators. The "Forced Outage Data Working Group" resolved these concerns to the satisfaction of all parties, and their conclusions drove the guidelines that Generators now follow in providing data.

AEMO would of course welcome the AEMC to participate in, or monitor the working group.

5.4 Facilitating Distribution Connected Generation

AEMO notes that the report has raised the processes to register small-scale embedded generation as an issue for resolution. NEMMCO had previously considered promoting a rule change to provide more flexibility for the aggregators of small generators to register multiple generators within one "Market Generator" registration.

Since that time AEMO has reconsidered its capacity to manage small generators in this manner. Issues have been recognised with respect to:

- Network configurations and responsibilities;
- Metering configurations; and
- AEMO's ability to manage a large number of such registrations.

AEMO prefers to undertake further investigation into these issues before progressing with the rule change. A Wholesale Market Development project: "Small (Embedded) Generation Integration Project" is being scoped and is expected to be receive executive approval shortly.

A rule change to facilitate the registration of small generators is a key part of the project's scope and it is hoped this could be proposed in late 2009 or early 2010.

6. Energy Markets Convergence

The expected growth in gas generation in a Carbon constrained future will lead to a greater inter-dependence between gas and electricity markets and the need for a level of convergence between the formal market mechanisms. AEMO appreciates the AEMC's concern that market settings and intervention mechanisms should be, as much as possible, consistent between the NEM and the various gas markets. We understand that the AEMC is recommending that AEMO take a leading role in exploring and promoting ways to achieve convergence.

6.1 Intervention Mechanisms

The AEMC has suggested that AEMO should be able to co-ordinate its actions, when necessary and as a last resort, to intervene to secure supply in all markets. It has further suggested that AEMO should explore where changes need to be made to either rules or procedures so that this can be undertaken within the current frameworks.

AEMO accepts that the proposed role, if endorsed, is consistent with AEMO's functions and capabilities. AEMO's ability to achieve a level of convergence between electricity and gas markets is, however, limited by the broader frameworks of those markets.

It is likely that much will be achievable for the NEM and the declared wholesale gas market (Victoria). It is important however to understand the limitations to AEMO's role in other gas markets where intervention powers remain vested with jurisdictions. The National Gas Emergency Response Advisory Committee (NGERAC) is tasked with attempting to develop advice for Governments towards co-ordination of jurisdictional responses to inter-state gas emergencies, although its recommendations are not binding upon jurisdictions. AEMO is a member of NGERAC but is not empowered to act unilaterally. Furthermore, NGERAC is not intended to have a role in intra-state emergencies.

Unlike the NEM and declared wholesale gas market, AEMO has no delegated powers to directly intervene in these other gas markets.

AEMO accepts this situation as being a result of the other gas markets having different historical circumstances to the NEM and the wholesale gas market. However in its final report we suggest the AEMC should note these issues as known and on-going limitations to AEMO's powers.

6.1.1 Rule Promotion

To the extent that consistency can be achieved in AEMO's intervention activities between the NEM and the declared wholesale gas market, AEMO agrees that it is in the best position to initially explore and then promote rule and procedure changes to bring this about. We concur that the similarities of the market objectives in the National Gas and Electricity Legislations should enable economically similar rules to be promoted.

We note that while the objectives in each market are similar, the markets operate under separate legislation and rules, and there is no provision for linked rule changes to be promoted. Whether this proves to be a practical barrier to the convergence of rules is yet to be demonstrated, however one option to resolve it may be the use of a single energy market objective.

6.2 Price Caps

AEMO concurs that the AEMC's proposal to write to those responsible for reviewing market settings to encourage them to attempt to align their work across the markets is an appropriate step at this time.

Convergence of settings is a worthwhile objective to the extent it can be achieved to minimise the risk of operational distortion as discussed by the AEMC, but AEMO also notes the following practical challenges:

- The pricing intervals and physical operating characteristics of each market are dramatically different, giving rise to differing risk profiles. For example, a market with a long pricing interval may incur much greater financial risk implications resulting from the setting of an extreme price;
- The different temporal nature of supply/demand balancing; and
- The gas markets do not have a set reliability standard to use as a basis for analysis.

6.3 Administered Pricing Arrangements

The report has raised the inconsistency of the triggering of administered price caps and the risk of inconsistent signals being sent to participants where one linked market is capped and the other not. Administered price caps are by their nature an intervention in the market and can be very intrusive to normal market operations and significantly impact both positively and negatively on participants risk profiles. Joint triggering can be attractive to reduce the risk of arbitrage, but will also greatly extend the intervention.

The issues that must be balanced in setting administered pricing arrangements, such as assessing systemic financial risks, are beyond the normal capabilities of AEMO and therefore we suggest other organisations may be better placed to lead an investigation into these matters.

7. System Operation with intermittent generation

7.1 Network Support and Controls Services (NSCS) review

AEMO notes the draft recommendation in section 9.1 of the report:

"In light of the importance of effective management of reactive power, we recommend that the network support and control services review commenced by NEMMCO be completed by the AEMO as soon as is practicable".

Clause 3.1.4(a2)(7) of the Rules requires AEMO complete the review and "deliver to the AEMC a report of the findings and recommendations of the review within 12 months of the commencement of the review". AEMO commenced the NSCS review on 29 July 2008 and released a draft determination on 25 November 2008 for consultation, for which submissions closed on 16 February 2009.

Submissions to the draft determination raised concerns with the premature timing of the review, given:

- the uncertainties in the design of the new national transmission planning arrangements commencing after transition to AEMO on 1 July 2009;
- the need to consider the implications of changes to those arrangements; and
- the potential for AEMO to plan NCSC levels as part of its national transmission planning role.

In light of these submissions AEMO sought and received AER approval to delay the final determination of the review beyond the required completion date of 28 July 2009, notifying the delay to the market in a NEM Communication on 15 May 2009.

Work on the NCSC review has continued and AEMO plans to release a second draft determination in late October 2009 for consultation, before releasing a final determination in early December 2009. If appropriate, AEMO would submit proposed Rules to AEMC to give effect to recommendations made in the final determination in mid January 2010. This review does not, however, address the full range of issues associated with the provision, or use of reactive power in the network and the market.

7.2 Formal requirements of Inertia markets

We agree with the finding in chapter 9 of the report that the existing market framework is able to support further review and to be capable of ensuring the operational arrangements in the market evolve as required.

One area where the market operating arrangements may need to evolve is in the arrangements for the provision of inertia. Inertia has rarely been an issue in the NEM to date, and particularly not in the mainland regions. As highlighted by the AEMC, this may change in the future as more non-conventional generation, particularly wind and solar generation, connect to the power system. As the operator of the system, AEMO would be in the best position to recognise any emerging concern. Should it be determined that action needed to be taken, a number of courses of action may be taken. One option may be to create centrally coordinated contracting arrangements for the provision of power system inertia, while enhanced ancillary service markets may also be possible. New arrangements of that nature may have significant impacts on market participants and reallocate costs and risk between parties.

As the 2nd interim report notes, low system inertia is now becoming an issue in Tasmania, requiring the implementation of special control schemes as a supplement to FCAS in order to the manage the relatively large credible generation and transmission loss contingencies in that region while continuing to meet the Tasmanian frequency operating standard. At times of low system demand in Tasmania, there is the prospect that a significant portion of demand would be met from a mix of local wind generation and high import over Basslink, neither of which currently provides any substantial inertial response to system disturbances thus resulting in an increase in the local FCAS requirement.

AEMO is currently participating with Tasmanian stakeholders in a review of the arrangements for managing inertia-related issues in the Tasmanian region, which is expected to be completed by April 2010. The objectives of the review are to:

1. To identify and quantify issues in achieving the frequency operating standard in Tasmania that can be attributed to increasing displacement of traditionally high-inertia generation with typically low or zero-inertia forms of renewable generation such as wind or solar; and

2. To assess whether changes to the current regulatory and market arrangements are required to promote very fast frequency control services (such as inertial response) to support the achievement of the frequency operating standards.

The 2nd interim report also highlights potential low inertia issues in South Australia that would affect the capability of the power system to withstand transient voltage fluctuations and would need to be managed by further constraining Victoria to South Australia interconnector flows below their current limits. To this end AEMO will also be co-ordinating similar reviews for the South Australian region.

7.3 Transparency of effect of intermittent generation on FCAS procurement and network capability

The 2nd interim report includes discussion on how FCAS recruitment and interconnector capability is potentially affected by the increasing penetration of intermittent generation[3] and

[3] Pg 93

presents a summary of the trade-offs implied. The concern relating to the adequacy of the transparency[4] of these arrangements, for which the AEMC is seeking feedback, is however unclear. With further clarification, AEMO may be able to provide an explanation of the processes involved in determining these parameters.

The 2007 Policy Document "Confidence Levels, Offsets and Operating Margins"[5] may be of use. This describes how historical observation of sub-dispatch-interval variations is used in determining the application of an operating margin. The actual operating margin applied to a constraint equation can be found by investigating individual equations.

Volatility in sub-dispatch-interval flows can arise for a number of reasons. For example, operating margins have been applied to QNI interconnector constraints to manage flow volatility which is suspected to have arisen due to demand fluctuations. The published margin does not attempt to distinguish causation.

At this time, AEMO has not had to apply greatly increased operating margins to constraints in proximity to intermittent generation centres.

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[4] Pg 97
[5] http://www.aemo.com.au/electricityops/170-0051.html