TRUenergy Pty Ltd
ABN 99 086 014 968
Level 33, 385 Bourke Street
Melbourne Victoria 3000

3 August 2009

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

Your reference: EMO 0001: 2nd Interim Report

Dear Dr Tamblyn,

Review of energy market frameworks in light of climate change policies – 2nd interim report

TRUenergy is pleased to have the opportunity to comment on the second interim report related to the current AEMC review into the impacts of climate change policies on energy market frameworks.

While the review covers a very large scope, we have restricted our comments to areas of key interest to us, or where we feel we have ideas to contribute to the debate. We have also contributed to a joint submission with a number of other participants which complements and expands in some areas on this response.

In summary, TRUenergy:

- Supports the NERG proposal, but presents some detailed comments, in particular suggesting greater clarity on NERG selection criteria are required.
- Does not support the G-TUOS proposal on the basis it does not address our key concern about network congestion impacting on generator investments, and that its treatment of existing generators deviates from good regulatory practice. In addition we do not believe the proposal will deliver on the AEMC's stated objective of enhancing locational decision making.
    - Rather we propose some "no-regrets" information provisions to enhance locational decision making under the existing framework, whilst options for more comprehensive means of addressing congestion continue to be explored.
    - The incremental information provisions, which would be beneficial whatever model ultimately emerges, should include:

        - The LRMC of augmentation of the network from each terminal station to the relevant reference node to allow likelihood of RIT-T outcomes to be assessed by the market; and
        - Implementation of a "full network model" to increase transparency on operational congestion.

- We support the AEMC proposals for inter-regional TUOS charging.

- Endorse the AEMC's findings related to retail price regulation and the need for greater flexibility in pass-through of CPRS costs. We also suggest that the issue of RET cost pass through also needs to be addressed.

- In relation to the proposals on Generation capacity in the short term, we:

    - Do not support the short term reserve trader proposal on the basis it increases the scope for distortion of the market;

    - Have serious concerns surrounding the practicality and cost effectiveness of the proposal to collect additional Demand Side information from retailers; and

    - Do not support the Load Shedding Management proposal as it is:

        - inconsistent with the existing NEM design; and is
        - unlikely to be cost effective given that the AEMC has already determined that risk benefits of setting the Market Price Cap (MPC) at existing levels, outweigh the inefficiencies (including demand side inefficiencies) that this creates.

- With regard to the issues identified surrounding system operation with intermittent generation, we propose that:

    - Reactive power procurement should be commercialised to enhance efficiency in its provision;

    - Inertia can be easily commercialised by minor alterations to the current FCAS market rules that would allow inertial response to be valued through the contingency markets.

These matters are explored in more detail in the attached submission.

For further discussion of TRUenergy's views on the matters raised in this submission, or the AEMC energy framework review in general, please contact me via (03) 8628 1000.

Yours sincerely,

Mark Frewin
Manager Wholesale Market Regulation

TRUenergy Submission – Review of Energy Market Frameworks in the light of Climate Change Policies – 2nd Interim Report

1. Connecting Remote Generation

TRUenergy supports the objective of the proposed NERG framework, namely to identify and make available to the market economies of scale related to sizing remote network connections to take into account likely future network requirements in the area (at this stage generation requirements have been discussed, but it is likely that similar situations could emerge related to potential remote load rich areas as well).

In general the model appears to present a reasonable attempt to balance the interests of connecting generators, customers and network businesses.

However there remain several areas of the proposal that we believe require modification, as set out below.

Pre-planning phase

Need for clear NERG zone assessment criteria

The AEMC has proposed that AEMO, as part of its NTP function, identify candidate NERG zones.

This is clearly a ciritical part of the proposed framework, as if the NTP does not identify appropriate zones, economic efficiencies may be lost. On the contrary, if potential zones are identified and do not later turn out to be economic, a lack of market interest or ultimately the AER as customer guardian may terminate development of the zone.

This may create a tendency for the AEMO to 'over-identify' possible NERG's – knowing that if it gets things wrong, others will likely weed out the less attractive options at a later date.

Certainly we would expect that many project proponents would be lobbying the NTP to seek to persuade them to assess potential areas for NERG potential (with the objective of increasing the value of partially developed projects, or licenced resources).

In this environment, we suggest the AEMO will need clear criteria upon which it can prioritise the various candidate zones and keep likely NERG zones to manageable levels.

Clarity on these criteria will be of assistance not only to AEMO, but also to potential project developers, who will be able to make their own assessment of the likelihood of a zone meeting the NERG requirement prior to investing in early stage resource exploration in a particular area.

As such, the need for clear and well articulated criteria on which NERG's will be screened and selected will be essential if scheme efficiency is to be maximised. There will no doubt be costs incurred by both project developers, NSP's and AEMO (and therefore ultimately customers) if excessive unproductive assessment work is carried out due to the assessment criteria being vague or unnecessarily loose.

Proposed criteria, and suggested areas for further work

During discussions on the draft NERG proposal put forward in the 1st interim report, a key question has related to the overall economic case for NERG's. In particular:

- Should they be assessed consistent with the existing regulatory investment test, or
- Should some other broader economic criteria be used - for example potential economic benefits to the wider community (ie. not just electricity producers and consumers) from making a low cost resource available to reduce the overall costs to the community of the eRET or CPRS?

From our reading of the report the Commission has not clarified the position on this critical question.

TRUenergy's view is that there is a case for the NERG proposal to take into consideration the broader economic benefits of the investment including its impact on RET costs (ie. the second option outlined above). The main reason for this is that we assume the current Regulatory test would already allow for development of a NERG (assuming improved co-ordination of connection applications) if the NERG was likely to deliver net benefits to the producers and consumers of electricity. However this appears unlikely, and therefore broadening the benefit pool is likely to be required if these investments are to proceed.

While this overarching question remains unanswered, page 159 of the 2nd interim report provides the following information on the proposed NERG criteria to be used by AEMO:

"In identifying NERG zones, the AEMO will have regard to the likelihood of substantial scale efficiencies materialising by considering:

- *The amount of possible generation capability (having regard to the commercial economic feasibility of generation entry); and*
- *That likely generation is sufficiently remote."*

The first of these criteria relates to the size of the possible resource in an area, and the economic feasibility of generation based on the resource.

This raises questions such as:

- Do only resource areas with currently competitive resource warrant NERG consideration? (eg. only wind now, not geothermal or other less proven sources? At what stage would a resource be considered proven for this assessment?).
- Does the economic assessment include the cost of transmission augmentations (ie. the NERG and other deeper augmentations) as well as the generation economics?

- What about areas with very large resources that are likely to take decades to be fully utilised – over what timeframe should potential NERG zones / connections be identified?

The second of these criteria is even less clear – as it is unclear how AEMO is to determine if a potential zone is "sufficiently remote".

In fact it is unclear why this requirement for remoteness is needed at all. Surely if a zone is very close to the existing shared network, but substantial scale efficiencies could be achieved by a NERG to that zone then they should be pursued?

Indeed this raises the question of wether this proposal can be used to develop shared network assets in zones already covered by the existing shared network – but which would require substantial network development if significant generation was to be connected. For example, significant renewable development proposals have been made in Western Victoria – which if they all proceeded would overwhelm the existing network in the area. A NERG style augmentation in this zone may unlock significant resource potential and economies of scale. Would the AEMO be unable to pursue such an approach because it was not "sufficiently remote"?

In the light of the above, we are not convinced of the need for the remoteness criteria and suggest it should be removed.

Another key question around criteria that should be addressed up front is whether or not NERG zones are only relevant for renewable generation options, or could apply to any economic future technology. For example, a NERG style asset to the coal seam gas fields in South East Queensland or Northern NSW could prove attractive if these resources replace coal in the initial transitional decades to the long term CPRS target. In the longer term NERG style connections could make sense to areas with co-incident coal and sequestration sites if Carbon Capture and Storage becomes economic, or potentially to sites applicable to other future technology applicable zones that may emerge in future.

TRUenergy would support this approach being technology neutral, as the economy of scale the NERG seeks to release is equally applicable to all forms of supply. In theory similar economies could also be available to customer load.

Overall recommendation on criteria

If full efficiencies are to be achieved from the NERG proposal – and more importantly if avoidable inefficiencies are to be minimised – it is critical that the AEMC clarifies the intent of the NERG scheme at the outset.

At a minimum, we recommend that the criteria for selection of potential NERG's by AEMO are:

- Technology neutral;
- Clear about the definitions of what "commercial economic feasibility of generators" means;
- Include both the cost of the generation and transmission (including deeper network congestion) in the assessment;
- Not include a "remoteness" criteria; and,

- Assess the wider economic benefits of potential resources in reducing costs of the eRET and CPRS to the economy (and not restrict the benefits to electricity producers and consumers as per the Reg test).

Planning phase

The information proposed to be supplied in the APR for each potential zone is supported. In addition to the estimates of the LRMC of the connection, an indicative tariff range would also be of assistance to potential developers. Potential capacity available at the proposed cost / tariff range should be outlined, along with any significant constraints that may limit additional capacity if this initial allocation was fully utilised would also be of value.

Generator connection enquiry

It is proposed that NSP's could levy a fee on receipt of connection enquiries to "recover any necessary costs and limit the scope for speculative or vexatious enquiries".

We are not convinced that such fees are appropriate at this stage of the process. In our view, it is a core function of all NSP's to be in a position to field connection enquiries. As such the cost of responding to such enquiries should be covered in their standing costs.

On the issue of speculative enquiries, it is noted that lodgement of a connection enquiry itself takes a lot of background work by a project developer in order to specify the technical basis for the connection enquiry. With this in mind, it is unlikely that a developer would place an enquiry without a reasonable intent to connect.

In addition, we note that one of the objectives of the AEMC in other parts of the review, are to increase locational signals for generators in order to enhance dynamic efficiency. With this goal in mind, surely it would be inappropriate to increase the costs to developers of fully exploring all connection location possibilities?

In our view, vexatious or speculative applicants should be weeded out at the contractual commitment stage of the process.

On this basis, we suggest this proposed fee is removed from the proposal.

In the event the commission persists with the idea of imposing this fee, at a minimum it should be a regulated charge in recognition of the imbalance in market power between the monopolist network business and the project developers. We note that previous attempts to deal with Network businesses have seen us charged unrealistic "consulting charges" from unregulated offshoots of the parent network business.

Proposed Standard Contract

In order for the NERG concept to support generation investment, it is important that it delivers a well understood cost structure to generator developers at the time of investment commitment for the life of the generation asset.

This principle is breached in the proposed contract because of the price re-opener provisions that would allow the NSP to reset the price in the contract every 5 years.

Surprisingly this proposed clause even allows the NSP pass through any cost over-runs that occur during the development of the asset. This removes all discipline from the NSP and undermines normal commercial incentives for them to deliver projects on budget.

The other reopening reasons can also largely be managed by the NSP (eg. debt / equity costs, O&M costs etc.).

If generators are to sign long term off-take agreements with energy customers at fixed prices that will support financing of generator projects, it is critical that cost stability can be delivered by major project cost components (eg. Transmission costs).

For this reason, the proposed cost reset provisions should not be part of the standard offer.

It may be acceptable that generators could waive certainty on this cost element and agree to re-opening provisions optionally if this worked for their project structure. This should be optional, with the standard NSP offer being at the higher end of the performance range – and options to agree to a lower standard for lower, but more volatile costs. Our reasons for this approach to setting NSP standards are explored in more detail below.

Options for bilateral negotiations

Standard contract conditions should be set to include stable real costs to generators for the life of a contract (not reset each year) in order to support generator financing. This would allow lower levels of price stability to be negotiated if acceptable to both parties, while recognising the realities of negotiating incentives on both parties.

The reasons for this recommendation are based on and understanding of the relative bargaining positions of generation developers and monopolist NSP's.

By the time a generator is negotiating this level of detail of the connection agreements, they are heavily committed to a particular site. This is well understood by the NSP, who also understands that that the developer has no other potential supplier to deal with.

In addition, NSP's are likely to take a conservative approach to agreeing to higher levels of service given the returns available under the regulated regime.

These outcomes are consistent with our experiences dealing with a number of NSP's across jurisdictions over the years.

These dynamics effectively eliminate any opportunity for service levels higher than the minimum requirements to be agreed (as NSP's have no incentive to do so, and generators cannot agree to pay monopoly rents to NSP's while remaining competitive).

For these reasons the minimum requirements of generators need to be aligned with the minimum regulatory obligations that NSP's need to offer.

In some cases generators may be willing and able to agree to lower standards in particular cases, and agreeing to this may be attractive to the NSP if it results in a lower risk profile to them in exchange for a lower cost to the generator.

In relation to the NERG proposal, the base contractual offer should stipulate a fixed real cost for the life off the generation asset in exchange for a fixed level of service. This will ensure that the standard requirements for generation financing can be met (ie. cost certainty for the life of the asset).

Additionally, if the generator is able to manage a degree of revenue uncertainty, this may create a point that can be conceded to the NSP in exchange for other concessions. However it is unlikely that an NSP would ever agree to increase tariff certainty – hence the AEMC approach is unworkable.

A further requirement of the negotiating framework should be that the NSP should not be able to charge more than the regulated return for assets required to deliver enhanced levels of service. The absence of this requirement in the regulated gas regime in Victoria, has led to the regulated pipeline provider demanding what we estimate to be 2-3 times the regulated WACC for an augmentation of the regulated network that is regarded by the rules as a "negotiated service".

Further expansion

The provisions related to further expansion are supported, as they offer reasonable protection to the access of foundation NERG generators (who continue to pay for their share of the development).

It will be critical that the standard contracts, or the rules, stipulate the obligations that all connectors will face in terms of potential payment or receipt of compensation related to congestion caused by future congestion. Indeed it is the lack of clarity in this area that appears to have undermined the access provisions of the existing rules (eg. 5.4A), which otherwise are designed to work in the way envisaged in this part of the NERG proposal.

Changes to future use

It is critical that the potential for future customer connections to NERG's is fully thought through and developed. This use must balance the need for ongoing access of generators who have funded the NERG, against the efficiencies of allowing customers to connect and make use of the NERG should that become desirable in future.

For generators, the key issue will be ensuring that access is maintained at the contracted levels, and that any appropriate augmentations needed to support he customer connection and maintain the contracted access are funded by the customer. Provided these requirements are met, any cost reductions created by sharing the cost of the NERG across the new beneficiaries should be shared with the existing NERG users (eg. customers and generators).

Deeper network access

While the NERG proposal is broadly reasonable in dealing with the funding and provision of the shared connection assets, it is not clear that this will interact effectively with the shared network. For example it is not clear that a NERG supporting a number of wind farms would necessarily create sufficient market benefits (given wind will deliver no reliability benefits) to result in the augmentation of the shared network that would ensure energy from the NERG was not constrained out of the shared network due to deeper network congestion.

Such an outcome would undermine the NERG concept, with its focus on providing a level of access to the NERG in exchange for a contracted revenue stream from the generator.

For this reason, more work needs to be done to ensure that the costs of the NERG include deeper augmentation costs needed to ensure that the contracted access levels of NERG generators can be delivered, as well as ensuring that participants (customers and generators) within the shared network continue to enjoy their contracted access levels.

Contestable NERG provision

Contestability would be a beneficial option, particularly if our recommendations for ensuring a workable negotiation framework are not adopted. At least if alternative NERG developers could be approached to offer alternative contract approaches to the incumbent NSP there may be some discipline on the NSP to take a reasonable approach to risk allocation and negotiation.

However a pre-requisite for a competitive approach being adopted is that the incumbent NSP could not exert its monopoly powers at the point of connection of the NERG to the shared grid. To avoid this, the AEMC should make it clear that the connection cost of a NERG should be no more than is required to fund assets directly related to its connection (including any deeper augmentations to support ongoing access for existing shared network users), and that the connection fee should only be able to recover the regulated return on these assets.

Careful consideration would be required to ensure that any contestable framework would be workable and monopoly power appropriately managed.

2. Efficient utilisation and provision of the network

TRUenergy does not support the G-TUOS proposal put forward in the 2nd interim report.

This proposal fails to address the congestion issues of concern to generators as it does not deliver additional network investment to remove congestion. In addition the proposal:

- Fails to adhere to AEMC precedent and good regulatory practice with regard to treatment of existing generators;
- Is likely to produce unstable price outcomes; and
- Will fail to achieve the AEMC's objectives to enhance locational signalling.

These matters, some proposals for greater transparency measures and recommended next steps are explored in more detail in the discussion below.

The G-TUOS proposal

Following an examination of the 2nd interim report, and subsequent discussions with AEMC staff, we understand the G-TUOS proposal and its objectives are as follows.

G-TUOS would impose a capacity based charge on all generators. The charge would be:

- Scaled to represent the relative difference in the LRMC of augmenting the Network at various zones.
- The scaled charges would be normalised around zero so that some zones would pay a charge and some receive a payment. It is not clear if these zones will be grouped on an NSP basis, NEM wide basis or in some other way.
- The charge would be set so that zones with more congestion would pay, and zones with less congestion would receive payments.
- It is proposed that the charge would be reset annually to reflect network developments over time.

We understand the AEMC objectives with this charge to be:

- Provision of enhanced locational signals – aimed at encouraging generators to invest in areas with less congestion, and providing some form of signal in retirement decisions.
- It is hoped this would lead to more efficient investment and provide some reduction in the development of congestion.

The need for reform

The key issues that TRUenergy believe need to be addressed are:

- eREt and CPRS will require significant investment in generation.
- The current regime does not adequately build transmission to remove intra-regional congestion to levels that adequately manage generator risks.
- When considering generation investment, investors need to have a reasonable expectation of getting their product to market for the life of the investment.
    - Revenue certainty – a requirement of financial viable investment, can then be managed via the contract market.
- To ensure an appropriate generator investment environment, an expectation that a plant will not be exposed to increasing congestion over the life of the asset is needed.
- Once an investment has been made, the regime must continue to deliver adequate certainty of costs and access on which the investment case was made.
    - These last two requirements illustrate that the requirements of incumbents and new entrants are identical (ie. this first is that costs are forecastable prior to investment, the second that the regulatory

assumptions underpinning the investment forecast remain valid post investment).

There are a number of approaches which appear to offer the potential to deliver on these requirements; however the G-TUOS is not one of them. Even on its stated objective of providing improved locational signals the proposal will not deliver any benefits.

Areas of concern regarding the G-TUOS proposal

The following table identifies key requirements for the transmission regime to meet the needs of generators as outlined above, as well as some general market efficiency measures that we understand are of interest to the AEMC from the 2nd Interim report and subsequent discussions. It then assesses the G-TUOS proposal against these criteria.

Assessment Criteria	G-TUOS	Comment
1. Adequate Transmission investment to remove intra-regional congestion	No improvement. G-TUOS funds no new investment.	Relies on RIT-T. This test builds only if overall market benefits exceed augmentation costs. Congestion that does not lead to load shedding unlikely to be removed – leaving constrained generators with congestion risks.
2. Locational Signal	Some change – but not clear that this is an improvement	Problems with the signal created include: • Likely to be unstable • May lead to perverse locational incentives • Short term nature of signal not consistent with long term asset timeframes • Inability of existing generators to respond to signal (noting unlikely to be significant in scheme of already sunk costs – just a wealth transfer).
3. Cost stability over asset life timescales	Negative impact	Annual cost reset not consistent with asset timescales. Costs likely to flip from positive to negative whenever a “lumpy”

		transmission investment removed congestion. Impact on existing generators not consistent with predictable investment environment and good regulatory practice.
4. Efficient cost signal	Negative impact	Cost artificial and not based on underlying costs of network augmentation (post scaling). Generators don't receive anything in exchange for costs incurred.
5. Entry barriers	Increased	Cost impost of G-TUOS and lack of addressing underlying congestion "amplify" existing problems related to congestion costs.

Overall this proposal would cause deterioration in the generation investment environment, not improve locational efficiency, and therefore fail to meet either the AEMC or TRUenergy objectives.

Further exploration of some specific areas:

Treatment of existing generators – good regulatory practice

The proposal to charge existing generators is a major departure from historic AEMC precedent and good regulatory practice.

During the AEMC's recent review of generator technical performance standards, the principle was clearly accepted that it was not efficient to force generators that had historically connected under old standards to have to upgrade their plants to meet new more rigorous standards. This approach appropriately recognised that to force major economic impacts on sunk capital would increase regulatory risk perceptions of the NEM with consequent long term impacts on costs of capital and consumer prices. As such, the AEMC adopted good regulatory practice in not imposing such costs in relation to technical standards.

Unfortunately, the draft proposal to impose additional G-TUOS charges on existing generators is not consistent with the precedent set in the generator performance standard review, and therefore deviates from good regulatory practice.

Treatment of existing generators - Retirement signals

It is unrealistic to expect that the proposed G-TUOS charge would be significant in adjusting the retirement decisions of large generators given the relativity between the sunk costs invested in the generator and the scale of G-TUOS costs.

The decision to levy charges on existing generators appears to be based on the view that this would create an additional "retirement signal". Given that existing plants cannot move to new locations, this concept is very different from the locational signal that a yet to be committed entrant could respond to. For a yet to be committed plant, a relatively small transmission cost differential could make the difference in location between two sites similar in other respects – thereby crystallising an efficiency.

However to materially impact on lifetime decisions of assets in which hundreds of millions (and in many cases billions) of dollars are sunk, these costs would have to be very high. It is difficult to see costs of this level being realistically imposed in this process – in which case the retirement signal argument is not realistic. As such any charges will merely be windfall benefits or losses – and not materially impact on asset life decisions.

RIT-T & transmission investment

At its core, the RIT-T aims to maximise the consumer and producer surplus from any chosen investment (reliability investments aside[1]).

The outcome of this is that regulated investments aim to maximise overall market efficiency.

However the perspective from an individual generator can be quite different.

For example, a peaking generator may be required to generate for a short period during the year, when peak demands occur. In order to fund its operations, this generator is likely to seek to sell "cap" contracts at the regional reference node. In order to be able to support these contracts, the generator will need to be able to generate sufficient capacity at times of high prices (likely to correspond to peak demand) to support the contracts.

The key question for this generator under the existing regime is – will the regulatory test deliver sufficient transmission to support its ongoing ability to access the reference node price when that price goes high (which is likely to correspond in many cases to times of peak demand).

In addressing this question, some key facts need to be estimated by the generator. These include:

- What are the network augmentation options (and their likely costs) available to increase capacity from the generator connection point to the reference node

[1] We note that in Victoria transmission planning is done purely on a market benefit basis and there is no non-economic reliability standard as applied in some other states.

(ie. what is the marginal cost of augmentation, and preferably the capacity at each augmentation cost level)?;
- What market benefits would relief of the forecast congestion create (ie. would these benefits overwhelm the costs of augmentation if required)?.

We note that insufficient information in these areas is currently readily available to the market.

In assessing the market benefits, key issues will include:
- Likely duration of the congestion – the less time the network will be congested the less likely sufficient market benefits will be delivered.
- SRMC differentials between generators behind the constraint.
- Any other factors that may deliver benefits (eg. Capex deferral, competition benefits etc).

Experience has shown that for low duration congestion events, market benefits are unlikely to exceed typical augmentation costs. While this may maximise net market benefits, it leaves individual generators exposed to significant risks – as failure to be able to access the reference price for even a short time can lead to catastrophic financial outcomes for the generator. (eg. $1Million per hour for each 100 MW if reference price is at Voll).

It is the difference between the market benefits (funded by customers) and the risk faced by generators that leads to the "gap" between what the RIT-T will build and what a generator may desire. It is this Gap that needs to be addressed to be stable across the life of a generation asset. Such stability would allow generator funds to be invested to deal with the gap, as it would be clear that funds invested would provide benefits for the life of the asset (not just until the next generator free-rides on the investment).

The G-TUOS proposal does nothing to address this "gap".

Pricing stability

As it stands the G-TUOS proposal is unlikely to deliver a stable price signal over time. This undermines its ability to impact on investment decisions.

One key driver of this instability is the "Lumpy" nature of transmission investments.

Consider a case where a particular zone was highly congested and was therefore a zone in which generators paid G-TUOS. In the event that conditions changed and it became economic to augment the network to remove the congestion, the "lumpy" nature of network investment could well mean post augmentation a surplus of capacity exists from that zone. The zone could well become one of the least congested zones within the network area, and suddenly generators within the zone would find themselves receiving G-TUOS payments.

While the generators in this first zone would receive a "positive" price shock, generators in other zones that suddenly change from being relatively un-congested to relatively congested would receive "negative price shocks". This is necessary for the proposed revenue neutrality to be achieved.

For both sets of generators it will be very difficult to forecast when and if such investments could occur – and therefore what the outlook for G-TUOS pricing is over the life of the generator asset.

This lack of stability undermines the potential for the proposed charges to be a credible investment signal. Investment signals can be responded to and managed. This signal is dependant on the actions of others potentially in sections of the network far removed from a particular generators local zone. This will be largely unforecastable by intending generators, and may well amplify the problems in this area under the existing regime.

Potential inappropriate incentives under the proposal

With its focus on relative pricing, the G-TUOS proposal aims to provide signals to encourage generator investment in relatively less constrained parts of the network.

A consequence of this approach, is that generators may find themselves facing charges to connect at a particular zone even if it is largely un-congested simply because it is relatively more congested than other zones in the region.

Similarly, and potentially of more concern, are cases where a generator may receive G-TUOS payments to connect to an already congested area, simply because the area is relatively less congested than other zones within a particular set of zones subject to a common revenue neutrality provision.

It is not clear that a suitable set of zones will be possible to construct to avoid the proposal creating inappropriate incentives of this type.

Recommendations

TRUenergy does not believe that the G-TUOS proposal achieves its stated objectives, and does not support it proceeding as a recommendation in the final AEMC energy market frameworks report to the MCE.

Despite this, we acknowledge the efforts of the AEMC in attempting to confront the difficult issue of intra-regional congestion. We note that the G-TUOS concept has been first aired in this 2nd interim report, and therefore has not had the benefit of wide industry input and debate. We also note that similar issues have been problematic internationally, and market designers have adopted a range of approaches to best meet the challenges faced by their local industries. This indicates that significant stakeholder engagement will be required to develop a proposal that supports the needs of all stakeholders to deliver suitable long term industry outcomes.

Increased transparency

In the short term, we would support short term "no-regrets" measures such as enhancing information provision to the market to ensure that investment decisions are made with as much relevant information as possible. In this regard we support:

- Publication of the LRMC of augmentation for each terminal station on the transmission network to increase transfer capacity to the relevant reference node;
- Implementaiton of a "full network model" to better model dispatch and publish short-run congestion information.

These measures would ensure investors considering generator or customer locations would have access to relevant network cost and dispatch cost information to better determine the likelihood of RIT-T investments occurring, or of being stranded behind a "high cost" constraint which would be unlikely to be augmented if congestion arose.

In addition to providing more clarity on short run network constraints, a full network model would also have the benefit of avoiding some of the rare but high cost market distortions that occur when AEMO faces un-expected network configurations and has to resort to creating constraint equations "on the fly". This activity created increased distortion in Victoria in early 2009 when the Bendigo to Ballarat 220kV line unexpectedly became the key transmission contingency in Victoria as a result of bushfire impacts. Because this outcome had not been considered likely by AEMO, it was forced to deal with it in real time – and is likely to have made sub-optimal use of the network potentially to great cost of the industry and consumers given market events at the time. A full network model, would have smoothly dealt with this event. In addition a full network model may unleash increased network efficiencies as it would not need to use "safety factors" often used in AEMO constraint equations.

We see such measures as "no-regrets" in that market theory supports the view that greater transparency of information increases efficiency.

Further exploration of congestion management approaches

In the mean time, we support more exploration of measures that can further enhance the access regime to increase investment certainty, congestion management options and network investment outcomes.

Discussion since the 2nd interim report indicates that significant differences in views and understanding exist between the AEMC and other stakeholder impacted by network congestion. For this reason a first step is to work through these areas of difference to ensure that all parties have well supported understandings of fundamental issues such as:

- Ability to measure network capability;
- Situations when RIT-T will and will not deliver transmission investment; and,
- Concerns expressed by the AEMC around entry barriers.

In this light, we propose that the AEMC continues to work with industry to develop a clear mutual understanding of the requirements of all stakeholders with regard to congestion, and seek to identify options to address the issue in a manner compatible with good regulatory practice and the national electricity market objective.

The G-TUOS proposal is not mature enough or well enough understood to be put to the MCE as any type of recommendation.

3. Inter regional transmission charging

It is important that this key issue is addressed. The proposed approach by the Commission appears to be a workable way forward.

Consideration could be given to what impact the addition of a large interconnection capacity could have on the allocation of network costs amongst exiting network users. It will be important to consider if this could result in undesirable tariff shocks or other instabilities. If such outcomes are likely, consideration should be given to mechanisms to manage them.

4. Regulated retail prices

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

Evidence provided in both the independent reports by Frontier Economics and the Farrier Swier report commissioned by the ERAA have persuasively argued the case that wholesale costs will be less certain and harder to forecast following the introduction of the CPRS.

A key element, identified in both reports, is that it is likely to take some time for a liquid secondary market in carbon permits to develop which would enable the price risk of the carbon scheme to be hedged.

In addition, the reports have both recognised that under the proposed CPRS scheme, the price of carbon will be determined by supply / demand and regulatory factors outside Australia. It is self evident that attempting to forecast the price in a complex, immature, and highly regulated international market is far more complex than the task of forecasting NEM prices (which itself has been problematic in past regulatory decisions).

In the light of this evidence we strongly support the AEMC finding in this area.

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

While regulation of retail prices continues in any form, there will remain a risk that its distorting impact could undermine competition or produce a retailer failure. For this reason, TRUenergy continues to strongly advocate the rapid transition to de-regulation of retail pricing in all jurisdictions. In the long term this will benefit both retailer and customers by creating an environment in which competition and innovation can thrive and deliver products that customers want, at reasonable prices.

However in the ongoing presence of retail price regulation, the proposals put forward by the AEMC are strongly supported and will help to mitigate some of the worse possible impacts related to the interaction of regulated retail prices and increasing retailer cost volatility created by the CPRS.

In particular we note the recommendation to provide a re-opening opportunity to retailers in the event of prices exceeding forecasts levels. This innovative approach has the benefits of putting the responsibility for deciding to increase prices squarely with the retailer – along with the public scrutiny and media attention such a decision would bring. Faced with the need to justify price increases in this environment, retailers will face strong discipline to maintain prices at the lowest sustainable levels.

In addition, this approach has the benefit of regulators retaining some powers to intervene, should the retailer proposals be unsubstantiable to the public. Hence the original concept of the retail price cap being a safety net against abuse of market power by retailers in markets were competition was not effective would be maintained.

The six monthly re-opener opportunities appear to create a reasonable balance between managing the risks of a potentially volatile carbon price, price stability for customers, and the regulatory and systems costs involved in any review / price change process. We note that while this will be an option, it will certainly not imply that costs will be reopened every 6 months – particularly in the presence of the cost and public scrutiny disciplines discussed above.

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

We remain concerned that existing regulatory approaches will not adequately deal with increasing costs associated with the expanded RET.

To date many regulators involved in setting regulated retail tariffs have opted to set RET allowances based on the prevailing REC price at the time of the determination.

Unfortunately, the design of the existing REC scheme has to date resulted in a boom-bust investment cycle, in which the market has gone from scarcity in REC's (and hence prices at the penalty levels), to a short term surplus as projects are completed to meet obligations later in the commitment period (and hence a callapse in the REC price). This design has been replicated (if not exacerbated) in the expanded RET scheme – and it is widely expected the scheme will again produce this boom-bust effect as excessive plants are built in the early years, in order to deliver on the peak target later in the scheme.

While this can be forecast, it is still a fact that the scheme will not deliver its objectives unless the excessive supply of renewable generators are built. In order for these projects to be financed, they need long term revenue certainty, which is delivered by signing contracts with liable parties (ie. retailers). Because of the cost structures of these renewable plants, these contracts need to be signed at least at the penalty price.

Having learnt the lessen of signing these contracts in the first RET scheme, and then not being permitted to pass through the full cost of the contracts due to regulators opting to use the short term REC market price (ie. post the collapse of the REC price), it would be reasonable to expect rational retailers not to sign such long term agreements. If this scenario was to eventuate, it may be difficult for the RET to be met.

We also note that as the expanded RET will require significantly more REC's to be procured by liable parties – which will increase the size of the impost that will need to be recovered. While under the original RET scheme the relatively small obligation meant incomplete pass-through did not undermine retailers, the impost under the new scheme will be at a scale more threatening to ongoing viability of the market.

It is therefore essential that in future regulators do ensure that regulated retail tariffs allow the full cost of contracted REC's to be fully recovered.

We would support an approach for RET cost-recovery similar to that adopted by the NSW Government for the 2010-13 Retail Price Review period for wholesale prices, which prescribes an allowance based on market prices, but with an LRMC floor.

5. Generation capacity in the short term

Proposal to adopt short term reserve trader

We note that this proposal is now being pursued by the Reliability Panel, and therefore will reserve our primary comments on this matter to that Forum. However it would be remiss not to re-iterate our concerns about the expansion of this market distortion, and note that such measures will create additional incentives for capacity to exit the primary market in the hope of achieving greater returns from the reserve trader "quasi" market.

We also believe the presence of the proposed "panel" of potential reserve providers is likely to leave AEMO highly exposed to being forced to accept excessive offers for reserve in the face of short term pressures to seek to resolve politically embarrassing reserve shortfalls. This will be at the expense of market customers – even those who have behaved responsibly and contracted sufficient reserve capacity.

The resulting uplift payments will also create disruptions to end use customers who have to fund these unhedged payments (or retailers to extent that regulated price caps apply).

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

It is unclear where the concern about commercial confidentiality of demand side data has emerged from. TRUenergy is comfortable to provide aggregated information about any demand side capability it has contracted to AEMO for use in reserve estimates (and indeed does so to the best of its ability in response to the annual SOO survey).

In addition we support the principle of seeking to ensure that full information is used in reserve assessments in order to avoid un-necessary and costly interventions in the market by AEMO.

Despite this attractive principle, we remain concerned that the proposal to increase data gathering in this area is not practical.

While retailers contract and can report on a certain amount of demand side management, they are not responsible for, or aware of a growing share of such activity – demand side management managed directly by end use customers themselves.

We do not see how additional rules reporting obligations on retailers will assist in identifying this type of activity.

We are aware of claims that if obligations are placed on retailers, they will be able to "aggregate" information from their customers for reporting to AEMO. We urge caution in this approach, as the administration involved in this activity would be very costly. In addition we believe results would be likely to be unreliable, as the only practical time to interact with most customers (apart from very large ones) is at the point of contracting. If customers subsequently decide to change their behaviour – this may not be picked up for several years. The imposition of additional customer interaction requirements would be very costly, and should only be contemplated by the AEMC following a robust cost benefit assessment.

Customers who intend to manage their own demand in many cases opt to take a pool price pass-through contract, which provides them exposure to the pool price directly (and therefore savings if they are able to reduce demand at time of high prices).

However customers with these intentions are by no means the only ones who find themselves on pool price pass-through arrangements. In many cases at the end of the term of their fixed price contracts, customers revert to pool price pass-through tariffs. Customers may be on these contracts for some time until they successfully negotiate a replacement fixed price contract with the existing or a new retailer. During negotiations on replacement contracts, the customer may be unwilling to indicate with any certainty its ability or willingness to respond to pool price signals. It will not necessarily be clear to the retailer if the customer intends to continue in the arrangement for some time, or enter a fixed price contract. As such the likelihood of accurate reporting of the DSP potential of the customer is minimal.

With these realities understood, it then becomes clear that if additional information is to be extracted from customers, some data collection direct from the customer either by AEMO or the retailers would be required. The logistics and practicalities of this are unlikely to be cost effective, and we remain unconvinced that obligations attempting to do this would be either cost effective or achieve their objectives.

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

TRUenergy does not support the proposed Load Shedding Management scheme, and recommends it is not part of the advice to the MCE.

This scheme recognises that one of the primary reasons many demand side providers may have decided not to participate in the market is that their opportunity cost exceeds the market price cap (MPC). On this basis it, proposes to pay customers their opportunity cost if they are shed in preference to uncontrolled load shedding.

This is a major departure from the existing market design in which customers benefit by not consuming if the costs exceed their opportunity value. Importantly the design does not pay the customer their opportunity value, it merely allows them to avoid paying for energy if its cost exceeds that value.

The reason this framework is not able to work in the instances identified by the AEMC, is that the MPC curtails the market response that would otherwise be expected of these customers.

In this light of this, we are concerned that he proposed LSM scheme attempts to address a symptom of the distortion created by the MPC, rather then addressing the problem itself. Surely if the distortionary effects of the MPC are significantly impacting on the efficient operation of the market, then reviewing the MPC itself would have been the logical place to start?

This is particularly the case in the instance of the LSM proposal – which itself will produce very negative side effects, in the form of large unhedgeable uplifts.

While we note that logic would suggest review of the MPC would make sense if its distortionary effects are becoming material, we also note that a very exhaustive process has been undertaken by both the Reliability Panel and the AEMC to determine the existing MPC. This process recognised the potentially distortionary effects of the MPC (including its potential to eliminate the potential for efficient demand response), and weighed these costs against the benefits of limiting market risks delivered by the MPC.

In the light of this extensive analysis, we suggest a strong case would need to be made to warrant payments in excess of the price cap being introduced. To our knowledge no such case has been put forward.

In summary we recommend that the LSM proposal should not proceed, as the costs incurred would be likely to exceed the acceptable economic cost of delivering reliability as determined by the Reliability Panel in its MPC setting process.

6. System operation with intermittent generation

Voltage control

We note the AEMC findings that voltage control is primarily provided by generator performance standards, NSP owned infrastructure and in some case by AEMO contracting for network control ancillary services.

It is with some concern however that we note the AEMC conclusion that should reactive become problematic generator performance standards "..can still be changed under current frameworks".

This statement indicates that the AEMC still considers mandatory provision of reactive as an appropriate approach.

On the contrary, TRUenergy is of the view that all reactive services should be commercially provided. This would allow new connectors who can easily provide reactive services to install excess capability in response to NSP or market requirements, or allow connectors who cannot easily provide reactive to make a commercial trade off about the cost of installing reactive plant, or procuring it commercially to support their operations.

While considerable thought would be needed to construct the optimum approach for a commercial approach to reactive provision, the efficiency benefits of this approach as opposed to the blunt mandatory provision approach should not be underestimated.

In addition, the experience of the rules being inadequate and unable to adapt to ensure sufficient reactive provision has been highlighted in South Australia where jurisdictional licensing requirements have been needed to ensure adequate connection standards are maintained in the face of inadequate in unresponsive NER approaches.

9a – Is it necessary to create formalised centrally coordinated contracting arrangements for the provision of power system inertia? If so, what is the nature of the processes by which those arrangements should be developed?

A more commercial approach to inertia is required. However some further consideration is needed before the optimum way forward in this area can be selected.

The first question that needs to be answered is why is inertia not currently valued in the market?

Inertia manifests itself in the market, in a very similar way to "fast" contingency services. Plant with high inertia tends to react against sudden changes in load and consequently supports maintenance of system frequency.

In the current implementation of the FCAS market, AEMO purposefully subtracts the effects of inertia from its calculation of FCAS response by generators. This appears to be because of their interpretation of the existing rules which indicate that only response that is created by "action" of the provider is to be considered.

AEMO have taken the short term view that inertia is not the result of action by the provider, and therefore should not be compensated. In fact, as is now becoming clear, inertia can be the result of investment action – and therefore should be compensated if it is to continue to be delivered.

This anomaly can be repaired by a minor rule change to rectify the existing clauses (outlined above), thereby ensuring inertia has its place in the market.

It will also have the effect of allowing a commercial trade off to me made between installing plant with inertia or paying FCAS costs.

The impact of making this change should be relatively minor, as it would presumably increase supply of fast FCAS on the mainland, benefiting the supply/demand balance in the transition without creating undesirable price shocks. This would then set up the market to value changes in the average levels of inertia across the system as the plant mix changes over coming years.

While this would be a simple way to incorporate inertia into the existing framework, it would suffer from the problems of the FCAS market in general – which relate to lack of longer term contractual mechanisms resulting from the existing cost allocation framework. To this extent some form of contracting approach to inertia may be more "investment friendly", however this is a broader problem in the FCAS investment environment more generally.

9b – Is there adequate transparency in the process by which FCAS recruitment and interconnector capability is affected by the increasing penetration of intermittent generation?

While we have not explored this question in detail, measures to increase transparency over how interconnector capabilities are determined and impacted by market developments should be encouraged.

In terms of FCAS provision, we have been uncomfortable with the current AEMO approach to determining regulation FCAS requirements for some time.

The current approach is based on a trial and error approach, under which AEMO reduces the requirement, tries it out for 3 months of so, and if nothing happens they reduce the requirement some more.

At a previous FCAS review, the NGF proposed a statistical approach to determining the requirement, which would offer the benefit of ensuring that sufficient regulation is procured to cover low probability events – which may not occur within the limited scope of a 3 month trial. The other benefit of this approach is it is likely to be more predictable over the long term – as parties may be able to infer future trends in system performance and use this to estimate how it could impact on regulation requirements. In contrast there is no way to predict what requirement level the AEMO approach may establish over the long term.

A review of how these requirements are determined would be worthwhile.