NATIONAL GENERATORS FORUM

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Dr John Tamblyn
Chairman, AEMC
By email: submissions@aemc.gov.au

Dear Dr Tamblyn

NGF Submission to Market Frameworks Review, 2nd interim Report

We write in relation to the Australian Energy Market Commission's Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report dated 30 June 2008. Please find enclosed the National Generators Forum's submission in response to the proposals contained in the abovementioned report.

This submission builds upon our response to the 1st Interim Report and reflects the ongoing discussions between the Australian Energy Market Commission and the National Generators Forum.

Our submission reflects our significant expertise and experience as National Electricity Market participants, our detailed discussions with other market participants, transmission bodies, regulatory agencies, and independent economic analyses.

We look forward to your positive consideration of the attached submission.

Yours faithfully,

Alex Cruickshank

Chair, Markets Working Group

NATIONAL GENERATORS FORUM

Submission in response to:

Australian Energy Market Commission
Review of Market Frameworks in Light of Climate Change Policies, 2nd Interim Report, dated 30 June 2009

Submission Introduction

The release of the 2nd Interim Report (the Report) on 30 June provided some useful insights into the AEMC's thinking on a number of key issues impacting the operation of the National Electricity Market (NEM); however, a number of the findings and draft recommendations, in our view, require further analysis and consideration before a National Electricity Rules (NER) change can be justified.

In this submission we have provided our perspectives on the key recommendations in the Report, to the extent possible in the unduly limited time allowed. We welcome the AEMC's work in these areas and note the difficulty and complexity surrounding these matters. We continue to make ourselves available through public forums, via submissions and through direct consultations to assist the AEMC with its consideration of these matters.

Background Information

The National Generators Forum (NGF) directly represents the 22 major power generators in the NEM. The installed capacity of the members is 44,129 MW in 2006, with an asset value of about $40 billion. Annual sales are over 180,000 GWh, having a value of about $6,835 million. This is over 95% of the total Australian market.

NGF members are publicly and privately owned businesses which generate electricity for sale and trade under the NER, and whose generating capacity is at least 300 MW. The Chief Executives of these businesses form the Board of National Generators Forum Ltd.

The purpose of the NGF is to be the respected market generator industry body recognised for excellence in influencing the development of Australian energy markets. Working Groups for the Market, Environment and Greenhouse carry out research and policy development activities in these spheres.

The NGF is committed to a competitive market which promotes efficient investment in new capacity. Reliability and safety of the electricity network is essential to consumers. The NGF is also committed to protecting the environment, including abatement of carbon dioxide emissions.

Executive Summary

G-TUOS Proposal

The AEMC indicates that its G-TUOS proposal is driven by the need to create an efficient locational price signal for new and retiring generation investment in the NEM. Each NEM region would be divided in to G-TUOS zones, which would be charged positive or negative fixed transmission charges, depending on the level of projected transmission congestion. As outlined below we have considerable concerns with the G-TUOS proposal; both from a theoretical and practical perspective.

The AEMC's G-TUOS proposal does not provide appropriate investor certainty as:

- it undermines financial viability of projects by introducing a new variable cost that cannot be hedged;
- it is not credible that an arbitrary and variable charge would facilitate long-term generation investment decisions; and
- the G-TUOS charge is simply a wealth transfer between generators and does nothing to address the underlying problem of lack of transmission.

The AEMC's G-TUOS proposal does not support decentralised decision-making as:

- relative charges which do not reflect actual costs imposed or incurred by participants will not lead to least cost delivered energy ;
- to the lack of any mechanism to hedge exposure to congestion will not support decentralised investment in generation capacity and, therefore, transmission and investment disincentives remain; and
- it promotes a centrally planned and regulated approach to all transmission decisions and undermines private investment in the NEM.

The AEMC's G-TUOS proposal does not provide a credible long-run locational transmission cost signal because:

- it is a scaled charge based on capacity, rather than energy. Therefore G-TUOS would not be cost-reflective, and imposes higher relative charges on low capacity factor plant; and
- inevitably G-TUOS, because it is required to reflect LRMC, will be volatile and unstable over time due to changing patterns of congestion, new entry and exit.
- calculating G-TUOS on the basis of LRMC is complex and dependent on highly uncertain assumptions

The AEMC's G-TUOS proposal does not ensure new transmission investment matches the preferences of new generation investment given:

- the charge does not provide TNSPs with recourse to any additional funds to build out congestion (i.e. does not fund augmentation of network to accommodate new entrants);
- congestion build out remains dependent on the existing RIT-T process; and

- the proposal fails to satisfy the real problem:a lack of transmission investment to match generation investment.

The AEMC's G-TUOS proposal is not appropriate as:

- it is not economically efficient, misinterprets the problem and creates a signal for signals sake;
- it ignores principles of dynamic efficiency and is only relevant from a static perspective; and
- existing generators can not effectively respond to the locational price signal.

The NGF does not endorse the AEMC's G-TUOS model and supports further work in this area including an investigation of a range of alternative options. Until such an analysis has been undertaken the NGF recommends the G-TUOS model and the possible repeal of 5.4A be parked.

Generation Capacity in the short-term

The NGF is concerned at the AEMC's proposals to increase regulatory responses in this area. The NGF does not support the AEMC's suggested approach to procuring reserve capacity and does not support load shedding management in the manner outlined by the AEMC. We believe further interventions in the market are likely to undermine investor confidence.

The NGF supports improvements in the area of demand side capability reporting and suggests demand side participants should have information obligations that are comparable to those of generators.

Connecting remote generation

The NGF understands the AEMC's rationale for developing the NERG proposal. However, the NGF is concerned that the NERG proposal:

- is regulatory not market driven and therefore will not be appropriate;
- is not cost reflective;
- does not resolve concerns in the shared network that flow from new connections and impact both incumbents and new entrants; and
- is not consistent with the G-TUOS proposal and that these two issues should be jointly resolved.

Inter-regional TUOS

The NGF broadly supports inter-regional TUOS but believes the link between inter-regional TUOS and augmentation of the shared network requires ongoing observation.

System operation with intermittent generation

The NGF believes that issues concerning reactive power and inertia require resolution.

Efficient Utilisation and Investment in the Network

Introduction

The AEMC provides that the existing frameworks are inadequate as:

- congestion is likely to be more material moving forward;
- congestion reduces generator certainty around access to market;
- congestion increases dispatch risks; and
- these risks and lack of certainty of access distort locational signals and delay new entry.[1]

To overcome these issues the AEMC has proposed a model of G-TUOS whereby:

- each NEM region is divided into several zones, to represent different levels of potential congestion;
- over each NEM region, the G-TUOS measure would be revenue neutral, but generators in some zones would receive payment and others would pay (if they were assessed to be in a potentially congested zone) while customer TUOS would be unaffected;
- the charges would reflect the change in the net present value of future network investment due to the projected change in generation capacity at each location, based on the forward-looking, long run incremental network costs. However, some scaling would be needed to achieve the zero-sum outcome. The charge would be on an installed capacity basis, rather than on generated energy; and
- the G-TUOS charges would be reviewed annually on the basis of a revised assessment of future generation investment.

Discussion

We agree with the AEMC that change is needed to improve investment in and efficient use of generation and transmission networks. However, we do not believe the change required is the AEMC G-TUOS proposal. Before detailing the AEMC's misconception of the current generator access to transmission issue and our suggested way forward, we outline our specific concerns with the AEMC G-TUOS proposal.

In this section we discuss the:

- application and limitation of annual fees;
- use of problems with the proposed "zones";
- benefit of G-TUOS as a retirement signal;
- size of the potential G-TUOS charge; and
- role of CPRS and RET in setting the retirement rate.

[1] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp. 23 – 29.

Annual fees

The application of a variable annual fee is extremely problematic. Merchant investors, and their financiers, require stability and predictability in policy, regulation and cost to facilitate investment in the NEM. Previously, the AEMC has indicated that stability, predictability and transparency are necessary factors in pricing regimes.[2]

Therefore, a yearly fee which will change as network investment occurs and is subject to the effects of future individual investment does not provide stability or predictability. Interestingly, the Scottish Government noted that the G-TUOS model developed in the United Kingdom, on which this proposal is based, resulted in high charges which were unstable, unpredictable and highly volatile year-on-year.[3] We note that the National Grid does not consider this to be the case; however, the National grid did concede that there were legitimate concerns regarding transparency of pricing arrangements with this form of charge.[4]

It is interesting to note that a similar arrangement existed in Queensland prior to the commencement of the NEM. We understand this type of model was abandoned and was not adopted at the commencement of the NEM as it was difficult to manage and was not stable[5] The G-TUOS model proposed is not suitably transparent, is not predictable, undermines investment, penalises incumbents already subject to economic losses as a consequence of congestion that is not being built out by the RIT-T, and increases the markets regulatory dependence contrary to the intention of the NEM at market start.

We do note that in discussions with the AEMC it was suggested that the fee may not vary as often as generators and investors may fear. Leaving aside the general scepticism these types of assurances provide investors trying to bank future projects or refinance existing projects, the AEMC has provided no detail as to how this is to be achieved. It appears inherently contradictory for the AEMC to acknowledge that congestion will be an increasing problem going forward under climate change policy and at the same time suggest charges will be stable. Such stability requires that conditions do not materially change (i.e. enduring congestion remains in-line with planner expectations and new congestion is not created by new entrants or incumbents).

Structure of zones

We believe the construction of zones with varying charges is a blunt instrument to send potential investors a signal as to where to efficiently locate. Leaving aside the value of the tool for the moment, the construction of the zones themselves is highly problematic in that the treatment of any given generator could alter depending on their inclusion in any given zone. We expect this will create considerable dispute around what are the appropriate zonal boundaries.

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[2] AEMC (2006), *National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No.22,* 21 December, p.2
[3] National Grid (2009), *Transmission Charging – a new approach*, May, p.30
[4] National Grid (2009), *Transmission Charging – a new approach*, May, p.23
[5] On 14 July 2009 NGF representatives asked the AEMC to provide qualification as to how the AEMC G-TUOS model differed materially from the Queensland scheme given our concerns. To date no response has been forthcoming.

There will be acute sensitivity to any opportunity or decision to include a generator in any given zone if it is seen as disadvantageous. Therefore, both at the initiation of this model and moving forward there will significant debate as to structure of the zones. For instance, one can imagine a circumstance where inclusion at the fringes of one zone results in a G-TUOS charge whereas inclusion in an adjacent zone would not. Apart from demonstrating such a model does not expose generators to “the marginal cost their use (or intended use) imposes on the network” as previously supported by the AEMC[6] it ensures a yearly and ongoing debate around zonal structures will ensue in what is becoming an increasingly regulated market.

In sizing zones one is in effect making a trade-off between the marginal impacts of a unique connection point and the variability of the fee. As in large zones that cover an entire region[7] will have relatively stable costs that do not reflect the individual impacts of a connection. Whereas zones which represent individual power plant connection points, should reflect the marginal cost of the connection of a plant of that size and type at that specific location. Administratively, the first may be the simplest, but on efficiency grounds the latter is more appropriate and reflects the desire by many generators for marginal cost pricing principles to prevail, whereby existing and new generators face the cost of their investment decisions.

Retirement signals

In a climate where there are growing concerns about the security of supply of electricity in light of the impact of climate change policies[8] on coal-fired plant which supplies around 85% of Australia’s energy need the suggestion that the theoretical benefits of a static trade-off between augmentation and early retirement seem misconceived at best. Furthermore, the AEMC has not detailed the “potentially high network or market costs” that may occur as a consequence of generator retirement. The benefits of a retirement in a congested zone may be the removal of existing congestion and the avoidance of the augmentation costs required to remove the congestion at that point in time. However additional charges will possibly exacerbate the stranding of assets and it remains unclear on what basis the AEMC is trying to “better inform retirement decisions” while fundamentally misconcieving the reason a stronger locational signal is required (to prevent congestion occurring).

In any case, let us assume for a moment that a transmission infrastructure decision was a simple trade-off between an incumbent’s retirement and bringing forward augmentation of the network. We must assume a circumstance would arise where congestion would only remain as the RIT-T would not be satisfied under the circumstances.[9] This means without recourse to the RIT-T an incumbent facing a G-TUOS penalty would have three

[6] AEMC (2005), *Review of the Electricity Transmission Revenue and Pricing Rules, Transmission Pricing: Issues Paper*, November, pp.31-32
[7] For G-TUOS to have any effect there must be more than one zone per NEM region. The Annual National Transmission Statement (ANTS) zones have been suggested as the basis for G-TUOS pricing. This leads to a problem in Tasmania, which constitutes a single ANTS zone. See http://www.aemo.com.au/planning/040-0053.pdf for definition of the 17 ANTS zones.
[8] See current Terms of Reference for Senate Select Committee on Fuel and Energy.
[9] Note: If the RIT-T was expected to build out congestion there would be little need for the AEMC’s G-TUOS proposal. It suggests as disconnect between what the RIT-T does do, should do and is believed to do by the AEMC.

options: (a) ignore congestion and continue to generate and bid on that basis; (b) retire existing plant and alleviate local congestion; or (c) fund an augmentation in order to build-out congestion.

By ignoring the congestion and continuing to generate and bid under the risks of constraints the generators current position will not be altered (apart from seeking additional cost recovery). The only differences will be that the affected generator will be further penalised with a G-TUOS charge until such time as that congestion is relieved in some manner. On the plus side, the G-TUOS charge will act as an additional disincentive (to the existing congestion) to further connections but unfortunately this requires the level of G-TUOS to be significantly high. Therefore, in such circumstances there is no notable benefit to the incumbent of the new G-TUOS regime as: the congestion remains; the generator does not have call upon the RIT-T; the charge forms an incumbency tax; the risk of congestion already acts as a disincentive to invest unless the new connection can displace the incumbent at dispatch and in those circumstances G-TUOS will disincentivise new connection only to the extent that that displacement does not exceed the G-TUOS charge levied against the new connection (which again penalises the incumbent).

If a generator decides to retire plant facing a G-TUOS charge than the congestion may be alleviated and they receive the economic benefit of not paying the G-TUOS charge but lose the economic benefit of generation. On that basis, it is difficult to assume that a profitable generator would retire on the basis of G-TUOS and therefore the G-TUOS represents an additional regulatory cost of doing business. If a generator was nearing retirement the cost would need to make retirement economically beneficial. Surely, even a significant cost would not expedite retirement by more than months or a year or two at most. The cost-benefit trade-offs across the NEM of this outcome are questionable at best.

If the ongoing costs of G-TUOS exceed the costs of funding an augmentation to relieve congestion then it is conceivable a generator or group of generators in an effected zone or zones will fund such an augmentation. If a sunk investment, faced with congestion not built out by the RIT-T and not wanting to retire is faced with a significantly high charge, one that deters new connections and reflects the cost of transporting each megawatt from each zone to the RRN,[10] their only alternative to doing nothing is to fund augmentation. This outcome does not seem appropriate if the AEMC intends that: load covers the cost of transmission networks; and that transmission pricing should be informed by a causer-pays principle. In this circumstance, a generator constrained off through subsequent investment is being penalised on multiple fronts.

The reason stakeholders have raised particular concerns with new location generator investment decisions is the failure to build sufficient network capacity so as to ensure incumbent generators are not constrained off. It is the impacts of new investment decisions (by new entrants and incumbents), and the lack of transfer capability available to new connections in certain locations which is the primary issue of concern; not encouraging retirement as a means to avoid the costs of augmentation.

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[10] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p. 30

Size of the fee

As detailed above we have significant concerns about the size of the fee which will be inefficiently levied against generators whose investments are sunk, on the basis that it encourages a trade-off between augmentation and retirement.

Similarly, for the fee to be reflective of long-run marginal cost (LRMC) it will need to replicate, as closely as is possible, the full costs to a new connection, of connecting at a specific location, on the NEM (and the full costs of existing generator future expansions in operations). That is it will need to reflect the marginal cost of connection for a causer of further congestion otherwise the incentive to connect at a constrained point may continue to be more economically beneficial then accepting the non-congestion costs associated with a non-preferred location.

This reflects the principle that only by facing the absolute costs (i.e. the true costs) of their actions can the relevant party be induced to make the most efficient decisions.

Carbon policies not G-TUOS will determine retirement and location trade-off

We agree that stronger price signals can influence behaviour and deliver more efficient decisions particularly for new connections where an investment is not sunk. However, the argument that retirement of sunk assets should be encouraged to free up scarce transmission capacity, while theoretically possible at the margin, does not reduce overall inefficient outcomes. To do this access arrangements need to ensure all generators when making investment decisions take account of their impact on the capability of the network to support efficient dispatch and avoid congestion.

Furthermore, in light of CPRS and RET policies, old plant will continue until the carbon costs rise to a level where that plant is no longer viable. Hence, the RET and CPRS policy will determine the retirement rate. Therefore, the primary reason for a G-TUOS charge should be encouraging new entrants to make a trade-off between efficient and inefficient locations based on the price duration curve of a location and absolute costs of a location. We doubt the AEMC G-TUOS charge will even deliver this unless G-TUOS represents the absolute (or as close there to) long-run marginal costs of transmission so as to drives dynamic efficiency.

Hence, our belief the proposal is poorly framed and is unlikely to provide the outcomes desired while inefficiently penalising generators who cannot respond to any additional signals.

AEMC's Analysis

Discussion

Recently, the AEMC commissioned Dr Darryl Biggar to undertake a paper on transmission investment and cost recovery principles and practice. In this work, it was noted that whereas traditionally coordination between generation and transmission investment was achieved through vertical integration, in a liberalised electricity market, such as the NEM, where generation and transmission are under separate ownership, that coordination must take place through other mechanisms – such as price signalling, contractual arrangements, and explicit coordination rules and processes.[11]

The AEMC's G-TUOS and the CSP/CSC proposal to deal with disorderly bidding appear to be the responses to this work and an attempt to differentiate between short-run and long-term pricing signals. However, it not only fails to appropriately consider the matters raised by Biggar, the AEMC fundamentally fails to understand the nature of the problem of generator access to transmission, given it has determined that a relative non-credible charge should be the main mechanisms for promoting outcomes that are supposedly consistent with the National Electricity Objective (NEO).

While the AEMC correctly identifies the need for more efficient decisions[12], consistent with Biggar's analysis (which as indicated above requires the consideration of investment decisions and operational decisions) the paper incorrectly identifies the problem as 'changes in this area, with particular focus on the incentives on generators, are likely to promote more efficient outcomes in the presence of congestion.'[13] This is not correct.

The existing market framework is inadequate because current transmission access arrangements are unlikely to build the additional transmission capacity required to ensure that congestion does not occur when a new entrant connects to the network or an incumbent expands its operations. This problem will be exacerbated in light of the CPRS and RET.

A reason, it appears, why the AEMC fails to conceive the problem in the manner outlined repeatedly by generators is that it appears to suggests the provision of and investment in regulated network services by TNSPs plays a primary role in addressing congestion created by new entrants when this is not the case. And that transmission investment is effectively divorced from locational decisions. [14]The AEMC highlights that congestion creates an uncertainty around access to the market[15]; however, they do not appropriately articulate the significance of this risk or that it is actually a barrier to entry as new entrants can not manage or appropriately hedge this uncertainty.

We believe the existing framework for providing short-run marginal cost (SRMC) signals to generators is robust. We believe this to be the case except where congestion occurs. In these situations a change to the dispatch or pricing may be required to address disorderly bidding. This is clearly the purpose of CSP/CSC type schemes, including as proposed by the AEMC.

Regarding the need for a locational signal, the AEMC do not appear to differ between the need for a locational transmission pricing signal which reflects the impacts of a new

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[11] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices,* p.5.
[12] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.23.
[13] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.23.
[14] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.25.
[15] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p.27.

entrants or an incumbents' expansion as opposed to locational signals in areas of congestion per. Including the purpose of those signals in relieving congestion[16] measured against other locational specific costs.[17]

The AEMC correctly indicates that stronger price signals will induce certain behaviours.[18] However, the AEMC does not draw the link between the quantum of signal and the extent of the impact on the network by the causer of congestion from their poor location choice. The AEMC also fails to capture how transmission access that reflects the absolute costs of transmission access will deliver more efficient location and retirement decisions and as a consequence of a decentralised decision-making process which considers other location specific costs minimise generation and investment costs overall.

Interestingly, the AEMC goes on to suggest a choice must be made between a generator facing short-run marginal costs and long-run marginal costs of transmission. Given these decisions are made in different timeframes we are unclear why the AEMC would depart from its previous analysis in the Transmission Pricing Review which suggested:

- when making a short-run decision it is appropriate for generators to face the short-run transmission costs, in the NEM these costs are made up of congestion costs and losses; and
- when making a long-run investment decision it is appropriate for generators to face the long-run transmission costs and short-run transmission costs.

Generators already face efficient signals in a regionally priced market where congestion does not occur. Therefore, the issue would appear to be not a choice between signals but ensuring the right signal is provided in the right timeframe.

Summary

The AEMC's conclusions appear to be that a relative charge as a substitute for true costs is able to promote efficient locational decisions, which is not correct, and that congestion only needs to be addressed at the margins once it is occurring and this can be done by managing disorderly bidding instead of stopping congestion and subsequent disorderly bidding arising at the investment and planning stages.

What is the actual problem what should the objective of a framework for generator access to transmission be?

Problems with the current framework

The NEO is to:

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[16]AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp.27-28.
[17] The AEMC endures with the term "non pricing signals". Whilst this term appears confused we note that locational signals also relate to fuel, water, labour, planning approvals are costs and they also have a price. One which is considered in a individual investors business model.
[18] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp.27-28.

> . . . promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to – (a) price, quality, safety, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system.[19]

In order to achieve the NEO the National Electricity Market (NEM):

- should be competitive;
- customers should be able to choose which supplier (including generators and retailers) they will trade with;
- should facilitate access to the interconnected transmission and distribution network; and
- be non-discriminatory between location, fuel type and existing participants and new entrants.[20]

This occurs via:

- exchange between electricity producers and electricity consumers through the spot market;
- wholesale contract market operation to manage financial risk and encourage competition;
- price signals for future investment in generation and transmission[21];
- decentralised decision-making based on legitimate price signals[22]; and
- transparent provision of all necessary information in a timely manner.

Currently problems arise where:

- competition in the wholesale contract market may be reduced by preventing generators from competing with their full capacity – stranded asset problem;
- the NER do not encourage efficient decentralised transmission and generation investment decision making through the competitive supply side of the NEM;
- generators are not provided with appropriate price signals at the time they are making their own investment decisions to drive dynamic efficiency and when congestion occurs operation decisions do not drive productive efficiency; and
- transmission investment fails to meet the needs of new entrants.

To resolve these issues we need to assess the manner in which investment decisions, operation decisions, and access to transmission decisions are made and how this satisfies the customer's interests.

[19] Section 7, National Electricity Law
[20] National Electricity Code Administrator at http://www.neca.com.au/NEM/index.html
[21] NEMMC0 (2008), *An introduction to Australia's national electricity market*
[22] Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices.*

Customer's interests in efficient investment decisions

The customer is best served by a NEM structure which ensures that:

(a) the least cost energy is delivered from the energy producer to the customer; and
(b) meets the NEO and promotes efficiency, including dynamic efficiency[23].

This can only occur when investors consider the total delivered cost of energy for their project from fuel source through to delivery of the product at the RRN at the time they are making an investment decisions. This means generation investors need to face the true value of all the costs associated with transmission and generation at a specific location. Absolute transmission costs are required to ensure neutrality with other location specific costs so investment decisions are not skewed.

A Framework for Generator Access to Transmission

A framework for generator access to transmission that is consistent with the NEO must:

1. provide appropriate investor certainty;
2. support efficient decentralised decision-making;
3. provide a locational LRMC transmission signal;
4. provide funding for new transmission investment; and
5. ensure new transmission investment matches the preferences of new generation investment.

Investor certainty means:

- with a high degree of certainty know or be able to forecast with confidence the cost of their access to the transmission system; and
- with a high degree of certainty forecast short run transmission costs and hence revenue. The SRMC of transmission is made up of congestion and losses, generators need to understand the extent to which the plant my have restricted access to the RRN due to congestion and as a consequence the extent to which their revenue may be curtailed as a result.

Support efficient decentralised-decision making means:

- generation investors need to face the absolute value of all the costs associated with a specific location which include:
    - the long run and short run fuel supply costs for that location;
    - location specific site costs such as, water, access and environmental costs;
    - long run and short run transmission costs for that location;
    - the ability to forecast with a high degree of certainty the long run transmission costs; and

[23] The AEMC noted in the Final report of the Congestion Management Review that dynamic efficiency should be addressed in future reviews.

- the ability to forecast with a high degree of certainty short run transmission cost (congestion and losses) and the price duration curve to facilitate the forecasting of likely revenue and to assist in the selection of plant type.

Investors already face a SRMC transmission signal; however, this needs to be reinforced through exposure to an absolute locational LRMC transmission signal to be consistent with other location specific costs (which are absolute costs).

Ensure new transmission investment matches the preferences of new generation investment means:

- new generators have flexibility with respect to transmission access to match that access and cost with the size and nature and operation of their plant and know with confidence that this level of access will be provided.

The tailoring of transmission access, represented through augmentation costs can fund the TNSP to build new transmission that matches new generation needs.

Hence, all these elements combined produce a transmission access regime designed to maximise competition in the wholesale contract market, to support decentralised decision-making in the competitive supply side of the NEM which will provide access prices to investors when generators make investment decisions.

<u>Therefore, the desirable features of an access regime from a generators point of view are the ability to choose a level of access that will be provided at a known cost with high degree of certainty for the life of the plant</u>. This will ensure that wholesale competition will be maximised and generation and transmission investment is made at least cost. These essential features are consistent with the NEO.

These essential features can be provided by either or a combination of (depending on the variables and methods of implementation) a deep connection charges regime (associated with a recognised transfer capability), nodal pricing, financial transmission rights or a CSP/CSC regime.

To ensure economically efficient investment under a deep connection charges regime or CSP/CSC or nodal pricing and financial transmission rights regime a new entrant or expansion generator would in addition to the payment of extension and connection assets be required to:

- pay to augment the transmission network by an agreed capacity, and
- when any generator generated in excess of their capacity provide compensation to other generators who are constrained on or off as a result.

This would provide all generators (new and existing) with non –firm access to the transmission system (generators could in theory purchase additional insurance from a TNSP to protect against lack of access due to transmission failure or maintenance activities but this would appear beyond the scope of this submission and the current AEMC review).

Operational decisions

Likewise, when making operational decisions, generators should see the short run marginal costs of transmission which includes congestion and losses. The NEM already provides this signal which, accept in the case when congestion occurs, drives efficient outcomes.

Consistency with Market Objectives

The above framework provides for a competitive market response and addresses the market objectives identified by Biggar, which are:

a) short-term operational objectives for generators and loads (dispatch efficiency, unit commitment, etc);
b) long-term investment decisions for generators (location, size, type of plant); and
c) both operation and investment decision by transmission network (co-optimised with generation investment/operation decisions).

The above approach is preferable. We note that the Biggar paper focussed on a regulated approach to transmission access. A regulated approach suffers from information asymmetries and weaker incentives so as to make transmission and generation investment decisions efficient a TNSP needs to have access to new entrant confidential and technical plant details and costs and the same wherewithal on how to best utilise that information. This will never be the case.

Next Steps

The AEMC has taken the first step to resolving the generator access to transmission issue and indicated that further work is needed in this area before a final rule change can be developed. In this regard we support the AEMC's endeavors and continue to make ourselves available for the dialogue ahead. Our objective is to develop a framework for generator access to transmission that, consistent with the NEO:

- provides appropriate investor certainty;
- supports efficient decentralised decision-making;
- provides a locational LRMC transmission price signal;
- provides funding for new transmission investment; and
- ensures new transmission investment matches the preferences of new generation investment.

While we have not ruled out any specific models, we have a framework upon which an efficient model should be based (as detailed above). Nevertheless, with the exception of the AEMC's G-TUOS proposal as it currently stands, we are open to a number of alternatives, and as part of the work being undertaken by the NGF, are engaged in analysing the following alternatives:

- financial transmission rights – the AEMC CSP/CSC proposal is a version;
- new generators pay for network augmentations – deep connection approach;

- generator contributions linked to augmentations – i.e. a revised G-TUOS model; and
- application of clause 5.4A of NER.

We are also examining the option of amending the RIT-T which, while arguably less efficient for customers and not meeting the objective and pre-requisites of the discussed framework, is possibly implementable and supported by some market participants.

A power point version of the points in this paper forms Appendix A and was provided to AEMC staff on 20 July 2009.

Removal of 5.4A

We do not support the removal of clause 5.4A.

The AEMC contends that individual access negotiations are unable to work in practice as it is difficult to identify the "causer" of reduced access on the shared network.[24] This is not correct and has little to do with the open access regime.

The causer of the congestion can be readily identified at time of connection when it concerns a new entrant. The system can be measured under normal conditions (a measurement protocol will need to be agreed) which recognises the transfer capability of existing generators as detailed in their connection (agreements).

We suggest that TNSPs have endeavoured to use ambiguities in the NER to circumvent their responsibilities. This mindset and an unwillingness to recognise transfer capabilities and not 5.4A itself has undermined negotiated financial access.

The issue of 5.4A should be resolved following a more rigorous analysis of the efficient utilisation and provision of the network.

Generation Capacity in the Short-term

The AEMC appears to make three recommendations as set out below.

1. The set of options available that AEMO can call upon to procure reserve be expanded further than the current RERT mechanism.
2. To facilitate more accurate reporting of demand side capacity.
3. To better manage load shedding by providing an avenue for it to contract for load reducing capability, which it can deploy when the only alternative is involuntary load shedding.

[24] AEMC presentation to NGF, CEC and Geothermal Association, 15 July 2009

Procure reserve capacity

Short notice reserve contracting

The NGF's position in relation to the improved RERT flexibility mechanism is outlined in its submission to the Reliability Panel. The NGF believes given that the Reliability Panel is currently assessing the submissions on the exposure draft to the improved RERT flexibility mechanism it would be premature to pre-empt its findings.

The NGF position in relation to the improved RERT can, however, be summarised as:

- it was noted that the Reliability Panel recognises that the RERT is yet another form of market intervention and therefore a market distortion, it remains unclear to the NGF why this "improved" RERT is required and the reasons underpinning these recommendations;
- detailed cost / benefit analysis is required to justify the proposed RERT flexibility arrangements. What are the potential short term gains from these arrangements versus long term efficiency losses through reduced investment certainty due to the on-going threat of increased interventions and regulatory creep;
- the NGF recommends using the existing market mechanisms such as the setting of VOLL as the primary basis to signal to the market the need for more investments to increase reliability. Secondly, the focus should be improvement of existing intervention mechanisms such as Directions (ie. compensation for unscheduled loads if directed) instead of introducing further refinements to new and untried market interventions; and
- as a safety net in the market, the Reserve Trader and now RERT has made no significant contribution to system reliability in 10 years. This change will increase the level of intervention whereas NGF would like to see the level of intervention being reduced with an eventual aim, of removing the RERT.

Standing Reserve

The NGF does not support the option of procuring Standing Reserve. The NGF is open further discussion on future alternatives or improvements to the energy-only market but it is of the view at this point in time that the need for fundamental change from an energy-only market is yet to be demonstrated. The market has been successful to date in delivering new generation capacity and demand side response and hence wholesale market re-design is neither warranted nor appropriate.

Further to this a Standing Reserve mechanism would be centrally determined by a regulatory body which would be a clear departure from decentralised decision making. As highlighted by the AEMC the other major shortfall of the Standing Reserve mechanism is the reserve capacity procured would need to occur well ahead of dispatch which would invariable lead to inefficient regulated decisions on the quantum, type and location of the Standing Reserve procured.

The NGF is concerned that similar to the proposed "improved" RERT flexibility mechanism a Standing Reserve mechanism would require further interventions in the market that would ultimately undermine investment confidence.

Prolonged targeted reserve

The NGF has similar concerns on the prolonged targeted reserve as expressed in relation to the Standing Reserve. The NGF does not support the introduction of such a mechanism.

Reporting of demand side capacity

The NGF supports the proposed recommendation to facilitate more accurate reporting of demand side capability for the same reasons as outlined in the Report.

The NGF believes demand side participants (DSPs) should have comparable information obligations to those of generators. Price sensitive loads greater than 30MW should provide comparable information to those of generators.

The aggregation of loads (i.e. hot water ripple control) should also be obligated to provide reliable information to the market. It is the NGF's strong view that unexpected DSP responses cause significant inefficiencies in dispatch. These sporadic responses also reduce contract market efficiencies such as short and near term outage cover.

The NGF believes that all DSPs would also benefit from better and more reliable information on the overall availability of DSP in the market. That is, an individual DSPs response to the market is equally reliant on the accuracy of forecast pre-dispatch prices and pre-dispatch availability.

Load shedding management

We understand the mechanism would work by contracting with participants to shed load at their declared value of reliability.[25]

Like many policy proposals, in isolation this proposal is implicitly appealing. It attempts to remedy concerns regarding load shedding in a seemingly orderly way. However, like many policy proposals created in isolation it may undermine or interfere with higher order objectives and efficient outcomes.

As it currently stands, retailers, generators and load have the option to engage in market solutions to demand side management arrangements. It is in many retailers' interests to engage in demand side management to minimise exposure to higher prices. Likewise, when a generator is highly contracted, they have an incentive to enter into demand side management arrangements to avoid high prices. Load has the incentive to enter into such arrangements where it is in their economic interests to reduce use in time of high prices.

As has been revealed load does not respond to high prices as readily as could be expected as electricity demand is reasonably inelastic. To overcome this the proposal

[25] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, pp.69, 172-173.

seemingly suggests that as load values the ability to use electricity over demand side management load will be paid the opportunity costs of not using energy.

This is a major departure from the current operation of the NEM. It is unclear how this will improve efficiency. And we believe it is not appropriate. In that regard, the AEMC's claims that load shedding management is more economically and socially desirable than involuntary load shedding is far from justified.[26]

Interestingly, the Reliability Panel has undertaken significant work in this area including in considering the implications of NEM reliability settings on demand-side management. It determined that the benefits of a higher Market Price Cap that will induce more demand-side participation did not exceed the costs and risks.

We do not support this proposal and suggest it is not consistent with the current market design as it:

- it further distorts the efficient operation of the market;
- it undermines current demand side management incentives;
- it introduces additional cost that needs to be recovered from market customers through retailers – this undermines retailer certainty and presents another unhedgeable market risk; and
- has an unclear and potentially perverse interaction with existing interventionist mechanisms, like the RERT, which already present a number of problems of their own.

Connecting Remote Generation

The AEMC states that the desired market outcome is for efficient and timely connections to energy networks, and that this will occur when:

- NSPs consider applications in a timely manner;
- new connections are provided on a cost reflective basis; and
- investment in connection assets is efficiently sized.

NSPs consider applications in a timely manner

This generic outcome is desirable in relation to all connections not only NERGs.

By deeming that the National Transmission Planner (NTP) will select NERG locations the AEMC has avoided detailing how market-led selection of remote location sites will be handled where there is a potential for multiple connections. Both the potential need to rely on selection of NERG zones by the NTP and the AEMC's failure to conceive of market-led selection of multiple connection sites makes it unclear how the connection process will be expedited. In fact, the pre-planning and planning stages alone present major time delays which will increase where commercial parties have identified sites not identified by the NTP. In fact, our main concern with the NERG proposal is the lack of

[26] AEMC (2009), Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report, 30 June, p. 69.

transparency on how the NTP will determine how many NERG zones are required and where such zones should be located.

In that regard, we require clarification or assurance that the work to be undertaken by the NTP is for informational purposes only. We support an approach whereby it is up to the market to decide where it wants to build NERGs, facilitated by TNSPs who determine, in association with AEMO, the economy of scale benefits. It is important that this element of the proposal is made explicit because ultimately it is not a "regulatory test" process and it will be participants that pay for the NERGs.

New connections are provided on a cost reflective basis

The major advantage of the NERG proposal and a feature supported by the NGF is the underwriting of the ‘overbuild’ by customers. Clearly, in circumstances where realising economies of scale in transmission provide a cost benefit to consumers and does not remove the need for new entrants to face their connection costs there are potential efficiencies. In this instance we suggest that a cost within a price band, similar to that identified by Biggar[27], between the incremental cost and the stand-alone cost of an asset should be allocated to the new entrant.

Interestingly, this underwriting model, in our view, could be rolled out more broadly in relation to efficient utilisation and investment in the network so if costs were attributed to a new entrant the portion over the increment that it was in the customers interests to build (due to economies of scale, routine network maintenance, or part of long-term planning) would be allocated to customers and not the new entrant who would pay the approximate incremental costs (or a cost within the price band identified by Biggar).

Where the NERG model falls down is that it does not make new entrants face their absolute costs of transmission. That is, while attempting to develop a locational signal for the broader network, the NERG proposal fails to dwell on the impacts of a new NERG connection on congestion and how such congestion will be removed. In essence, this means NERG connections are not cost reflective as they do not resolve how impacts on the wider network will be resolved.

Investment in connection assets is efficiently sized.

As discussed we support the NERG consumer ‘underwriting’ concept as a mechanism to overcome lumpiness and realise economies of scale. However, it fails on other grounds. While economies of scale will be realises for all new connections drawn to the NERG hub the interaction with the wider network and efficient trade-offs more generally have not been considered at length in the AEMC’s analysis.

Consider the AEMC primary assumption:

[27] See Biggar, Darryl (2009), *A framework for analysing transmission policies in the light of climate change polices*

> The entry of renewable generation is likely to be clustered in certain geographic areas that are remote to the existing networks.[28]

This conclusion glosses over a number of issues.

We all acknowledge that the RET and CPRS will stimulate significant investment in renewable capacity. However, what we imply by this is that the RET is bringing forward a significant amount of renewable investment. As such, given that wind power (in the absence of any new large scale hydro facilities) is the most commercially viable form of renewable generation, the RET is likely to result in a significant increase in wind farms.

However, it is not automatically conclusive that wind farms will locate in certain geographic clusters. What is correct is that the best wind is located in certain geographic clusters. Therefore, if other costs are not a factor for a new entrant, then every new entrant would obviously choose the location where wind (fuel) is at its best. Hence the AEMC has failed to consider trade-offs between locational costs like labour, planning, and most notably transmission and the price duration curve of a location.

Wind is available everywhere; however, the quality of that wind varies. Hence, if a wind farm had to elect between a location with no transmission costs and 11 kilometres per hour average wind and a second location with 15 kilometres per hour average wind but high labour costs and high transmission costs it may be that the least cost delivered to customers would flow from the location with 11 kilometre per hour wind. Such an outcome would be consistent with the NEO. Therefore, by prohibiting this trade-off occurring, (and only presuming NERG zones transmission savings are the most critical issue) the AEMC may be failing to deliver the least cost delivered energy to consumers.

It may well be that when it comes to wind and similar projects the only relevant factor is fuel. However, this does not mean that impacts on the shared network should be ignored or not considered in an individuals investment. In fact, it appears entirely inconsistent to at one level be supporting G-TUOS as a retirement signal to reduce the need to augment the network, by in effect penalising sunk assets for congestion while subsidising connections for renewables irrespective of the congestion that may flow from a proposed NERG.

This is not to say that consumer underwritten projects should not occur but to indicate the formalisation of such a strict policy has significant downsides, which the AEMC has not addressed in its reports or in discussions with members of the relevant consultative sub-committee.

A separate issue, and one where the AEMC's thinking is appropriate, is the treatment of the marginal connection once capacity on the connection asset is full. We support the approach that the marginal connection either: (a) pays compensation in the event an existing generator is constrained; (b) agrees to fund an augmentation; or (c) agrees to be constrained off.

Interestingly, this efficient allocation of costs is entirely consistent with clause 5.4A of the NER. A section the AEMC has suggested should be removed. We would suggest the

[28] AEMC (2009), *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June, p 13.

distinction between the shared network and NERG connection assets is essentially arbitrary. What needs to be resolved is how to develop a measurement protocol for system normal transfer capacity for both existing and new generation.

NERGs versus G-TUOS

While the NGF believes further work is required to resolve the broader issue of efficient utilisation and provision of the network we note that the NERG proposal and the G-TUOS model appear inconsistent in the face of similar issues.

In the Report the AEMC notes that one of the key reasons for supporting the NERG process is that it "maintains locational signals for new entrants". Interestingly, such an approach to managing congested areas of the grid would be more stable than imposing a retrospective and unstable G-TUOS on incumbent generators who do not have the benefit, like new entrants do, of being able to change their location.

It could be argued that since the AEMC notes, on the basis of the modelling performed by ROAM and IES, that serious congestion is likely to arise in certain areas of the grid, for instance in areas of high renewable potential, that the process for NERGs could be extended to the shared network. That is, where congestion is becoming or likely to become meaningful for participants, but transmission investment is unlikely to pass the RIT-T, then this kind of funding approach could be applied (but interested parties should initiate the process through expressions of interest) with each new entrant paying for the incremental costs required for their use of the network (this includes a share of the true costs required to support the new transmission). Over time as new generators enter the full costs of the transmission would be recovered.

It could be argued such an approach is forward looking (strategic) and maintains locational signals for new entrants and maintains the level of access to the network for existing players. Importantly, the charges are highly stable, unlike G-TUOS.

While the NGF is not advocating such an specific approach at this time we suggest this initial analysis indicates that the inconsistency between the NERG and the G-TUOS proposal is not appropriate and supports: our calls for a more rigorous investigation of the issue of efficient utilisation and investment in the network; the abandonment of the current G-TUOS proposal; and further development of the NERG proposal.

Inter-regional TUOS

We broadly support the development of an inter-regional TUOS charge. In supporting this proposal the NGF agrees with the AEMC’s findings that transmission investment to support flows between regions is currently inhibited by the absence of an inter-regional TUOS mechanism.

We note that some shared network augmentations have not been considered due to the lack of inter-regional transmission charging[29] and agree with the AEMC's position that absence of such a charge is a barrier to improved coordinated network planning.[30]

We agree that a load export charge is an appropriate and proportionate response at this point in time but note the Report does not signal to the required degree of confidence whether the AEMC and NGF concerns will be resolved following the adoption of a load export charge. That is, will the load export charge create the incentive to consider such augmentations and will it improve coordinated planning or will it simply shift cost allocations without improving outcomes?

We expect the charge will make a positive difference but this is dependant upon pricing methodologies and therefore believe the issue requires ongoing monitoring.

System operation with intermittent generation

Reactive Power

We note the ongoing issue with reactive power, which is likely to be aggravated by the addition of more intermittent generation.

The current mix of compulsory acquisition via technical standards and provision by network service providers using regulated charges seems unlikely to promote overall efficiency in accordance with the NEO. In particular, the dual role of TNSPs in approving performance standards for generators and as providers in their own right is difficult to reconcile.

While we accept that this issue may not be of sufficient importance to justify a place in the current review, it nevertheless should be reviewed in the near future.

Inertia

In relation to inertia, we note that AEMO currently go to significant lengths to eliminate the benefits due to generator inertia from the measured products traded under the market ancillary services regime.

We suggest that a simple change in the NER would allow these benefits of inertia to be included in these products, thus providing a market signal for the connection of inertia to the electrical network. We believe this would simplify both the process of defining the FCAS requirements and the process of determining the amount of FCAS service actually delivered.

[29] NGF, Public Forum Discussion Paper submission, p 6.
[30] AEMC (2009), Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report, 30 June, p. 44.

Appendix A – Power point presentation on efficient utilisation and investment in the network

NGF

N A T I O N A L   G E N E R A T O R S   F O R U M

efficient utilisation and provision of the network

preliminary submission

in response to chapter 3 of the AEMC,

Review of Energy Market Frameworks in light of Climate Change Policies,

2nd interim report

Page 1

NATIONAL GENERATORS FORUM

What is the problem?

- The AEMC provides that the existing frameworks are inadequate as:
  - congestion is likely to be more material moving forward;
  - congestion reduces generator certainty around access to market;
  - congestion increases dispatch risks; and
  - these risks and lack of certainty of access distort locational signals and delay new entry.

Page 2

Why is the problem arising?

- The primary cause of ongoing congestion is lack of transmission investment to support new entrants.
- Decentralised decision-making by individual participants does not take account of generation and transmission investment requirements.

NATIONAL GENERATORS FORUM

Can the current framework resolve these issues?

- There is no readily accessible mechanism to meet generator transmission investment needs – RIT-T primarily concerns reliability.
- The current application of the NER deters private transmission investment.
- Connected generators transfer capabilities have not been recognised.

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NATIONAL GENERATORS FORUM

Generator investment pre-requisites?

The basic requirements to support the financial viability of any power project for the life of the project are:

- access to fuel for the life of the investment which provides certainty with respect to price and volume;
- a contract market that can provide creditworthy transparent and liquid management of price volatility (i.e. price certainty);
- the ability to forecast revenue and costs with a high degree of certainty this includes:
  - the quantity of energy that can compete for dispatch in the market at the regional reference node for the life of the project, (i.e. quantity certainty against constraints and loss factors); and
  - Other long-run charges.

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N A T I O N A L   G E N E R A T O R S   F O R U M

What is our objective?

- To develop a framework for generator access to transmission that, consistent with the NEO:
  - provides appropriate investor certainty;
  - supports efficient decentralised decision-making;
  - provides a locational LRMC transmission price signal;
  - ensures new transmission investment matches the preferences of new generation investment; and
  - provides funding for new transmission investment.
- The AEMC's G-TUOS model should be measured against these criteria.

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AEMC G-TUOS - Provides appropriate investor certainty?

- ☒ Undermines financial viability of projects by introducing a new variable cost that cannot be hedged.
- ☒ It is not credible that an arbitrary and variable charge would facilitate long-term generation investment decisions.
- ☒ The G-TUOS charge is simply a transfer between generators and does nothing to address the underlying problem of lack of transmission.

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AEMC G-TUOS - Supports decentralised decision-making?

- ☒ Relative (not absolute) charge does not provide least cost delivered energy – charges need to reflect the absolute costs.
- ☒ Does not provide a mechanism to support decentralised investment in generation and transmission and investment disincentives remain.
- ☒ The AEMC's approach focuses on transmission investment to the detriment of generator investment decisions.
- ☒ Promotes regulated approach and undermines private investment in the NEM.

NATIONAL GENERATORS FORUM

AEMC G-TUOS - Provides a long-term locational signal?

- ☒ Because it is a scaled charge, the G-TUOS charge would not be cost-reflective, and is not an efficient signal.
- ☒ Because it is forward-looking, the G-TUOS charge is highly dependent on the underlying assumptions that are adopted, and will also not be stable.
- ☒ Therefore such a charge is ineffective as a long-term signal.

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NATIONAL GENERATORS FORUM

AEMC G-TUOS - Ensures new transmission investment matches the preferences of new generation investment?

- ☒ The charge does not provide TNSPs with recourse to any additional funds to build out congestion (i.e. does not fund augmentation of network to accommodate new entrants).
- ☒ Congestion build out remains dependent on the existing RIT-T process.
- ☒ Fails to satisfy the real problem: lack of transmission investment to match generation investment.

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legitimacy of G-TUOS as a retirement signal

NATIONAL GENERATORS FORUM

G-TUOS as a retirement signal

- The AEMC provides that a zonal G-TUOS charge will provide a locational retirement signal to incumbent generators.
- The NGF disputes the AEMC's logic and suggests this recommendation neither acknowledges or address the actual problem (see slide 3).

Inefficient to charge sunk investment

- An efficient signal will prevent congestion occurring not penalise those exposed to congestion.
- As such charging sunk investments a locational signal is inefficient in that a generator's only response is to:
  1. ignore congestion and continue to generate and bid incorporating G-TUOS; <u>or</u>
  2. retire existing plant; <u>or</u>
  3. fund an augmentation in order to build-out congestion.

N A T I O N A L   G E N E R A T O R S   F O R U M

(1) Ignore congestion and continue to generate and bid incorporating G-TUOS

- ☑ Acts as an additional disincentive to new entrants to locate at that location.
- ☒ Introduces a new penalty payment for generators already facing congestion costs – incumbency tax.
- ☒ Charging incumbents makes location less attractive but does not make new entrants consider their impact on the network – no benefit to network.
- ☒ This outcome will not alleviate existing congestion or support new entrants.
- ☒ This outcome does not encourage investor certainty or encourage decentralised decision-making.

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(2) Retire existing plant

- ☑ The extent to which a retiring generators contributes to congestion, that congestion may be relieved.
- ☑ New entrant can take retirees transfer capability to the level where there is no congestion. In the short-term this may negate the need for augmentation – provides a static trade-off.
- ☒ Any additional transfer capability required by new entrants will not be built under this G-TUOS model.
- ☒ Retirement is not a systematic resolution of transmission shortages facing new entrants or for building out congestion.

N A T I O N A L   G E N E R A T O R S   F O R U M

(2) Retire existing plant (cont . .)

- ☒ Retirement does not price congestion accurately or encourage dynamic efficiency.
- ☒ The G-TUOS charge would need to be significant to induce retirement earlier than originally planned (i.e. even by months) – how can such a penalty be calculated and justified?
- ☒ The cost-benefit trade-offs across the NEM of such outcomes are unproven.
- ☒ Unlikely to provide a signal which encourages investment.
- ☒ Neither fair, efficient or transparent and appears ideologically driven.

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NATIONAL GENERATORS FORUM

(3) Fund an augmentation in order to build-out congestion

- If cost of ongoing G-TUOS exceeds augmentation costs than generators may be likely to fund augmentation.
- This outcome does not seem appropriate and is not driven by causer-pays principles.
- Indirectly requires affected generators to fund augmentation costs.
- Further emphasises that G-TUOS is not solving the actual problem but increases the costs of the current framework.

N A T I O N A L   G E N E R A T O R S   F O R U M

Summary – AEMC G-TUOS proposal

- ☒ AEMC G-TUOS charge mischaracterises the complexity and effectiveness of this charge in making transmission available.
- ☒ Is not an economically efficient signal.
- ☒ Ideological basis - signal for signals sake.
- ☒ Static perspective ignores principles of dynamic efficiency and misinterprets problem.
- ☒ Does not resolve shortfall in transmission investment as a consequence of new investment decisions.

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N A T I O N A L   G E N E R A T O R S   F O R U M

next steps –
exploration of revised options

NATIONAL GENERATORS FORUM

Options for generator access

- A framework for generator access to transmission must:
  - provides appropriate investor certainty;
  - supports efficient decentralised decision-making;
  - provides a locational LRMC transmission signal;
  - ensures new transmission investment matches the preferences of new generation investment; and
  - provides funding for new transmission investment.

- These outcome are consistent with the NEO.

NATIONAL GENERATORS FORUM

Options for generator access (cont.)

This requires:

- consideration of dynamic efficiency and productive efficiency – competition and investment decisions;
- a signal that is stable, predictable, transparent and proportional to the users impact on the network;
- can address issues of scale effects, lumpiness and cost allocation within a framework that includes a key role for the regulatory based transmission planning; and
- consistent application of ‘causer pays’ principle.

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N A T I O N A L   G E N E R A T O R S   F O R U M

NGF options for further analysis

- Financial transmission rights – the AEMC proposal is a version.
- New generators pay for network augmentations – deep connection approach.
- Amended RIT-T.
- Generator contributions linked to augmentations – i.e. a revised G-TUOS model.
- Application of clause 5.4A of NER.

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