NATIONAL GENERATORS FORUM

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13 April 2006

The Chairman
Australian Energy Market Commission
PO Box H166
Australia Square, NSW 1215

Submission by email: submissions@aemc.gov.au

Dear Dr Tamblyn,

RE: - Congestion Management Review Issues Paper - 3 March 2006

The National Generators Forum (NGF) welcomes the opportunity to comment on the Congestion Management Review Issues Paper.

As concluded in our response to the Transmission Pricing Issues Paper in the NGFs' view the current arrangements for addressing intra regional congestion management do not support efficient short term production decisions. Also the locational investment signals create considerable uncertainty as there is no guarantee that new investors in generation will take into account the cost of transmission in their locational decisions. As a result there is a risk that the economically efficient operation of the market will continue to be compromised.

In our submission we noted that proper signaling of congestion and the provision of locational investment signals may require consideration of other issues beyond the scope of the Transmission Pricing Review. Also in past submissions (to the ACCC and NECA) on this topic the NGF has identified transmission access rights as key to providing the certainty to encourage efficient investment in generation assets. Alternatively this review by the AEMC into congestion management may offer an alternative solution.

Our response to the congestion management review is framed in the same context as our transmission pricing submission ie primarily in relation to the current arrangements for providing both long term locational and short term production transmission pricing signals and their impact on efficient energy market outcomes.

The objective of transmission pricing

The NGF agrees that it is important for transmission pricing to drive economically efficient outcomes to the extent that pricing affects participant decisions, the timeframe of those decisions and the resultant level of necessary transmission investment. Transmission prices are of importance to generators when generators are making (a) locational investment decisions, or (b) production and consumption decisions.

To promote efficiency of generation investment and operation, transmission pricing for generation should reflect appropriate LRMC and/or SRMC price signals at the time that a relevant decision is being made.

The NGF agrees with the approach outlined by the Commission.

a. (long term) locational investment decisions;

The cost of the physical network is only relevant when a generation investment decision is made. There is only a need for generators to consider Transmission LRMC as a one off cost reflecting the incremental transmission costs of the generator's investment decision. Further, such assets, once developed, have no alternative use. The expenditure on such assets is referred to as 'sunk'.

Sunk transmission costs should be recovered in a way that minimises impacts on production and consumption decisions. This should occur, as the AEMC notes, as a fixed charge at a point where the elasticity of demand is lowest. Application of the sunk costs to consumers is unlikely to impact consumption and utilisation of the network whereas the same charge applied to generators would distort efficient energy consumption and dispatch. Recovering sunk costs from generators does not have any locational or production and consumption signaling function because the cost has already been incurred and subsequently cannot influence future behaviour. Therefore the NGF considers that the current transmission pricing framework for recovering sunk costs from consumers is appropriate.

b. (short term) production and consumption decisions;

The capital and fixed costs of the physical network are irrelevant to the determination of short run marginal cost (SRMC) because it is incurred regardless of the decisions of network users. The SRMC of transmission is largely made up of the cost of constraints and losses. This suggests that to promote efficiency in the short run, the price of using the transmission network should equal the cost of constraints and losses.

Current market arrangements for generator transmission pricing.

In the Transmission Pricing Review the Commission outlined the current pricing arrangements which provide the consumption, production and investment signals in the NEM, namely:

- regional pricing structure (section 6.1.1);
- non-firm grid access for generators (section 6.1.2); and
- the transmission investment arrangements, including the Regulatory Test (section 6.1.3).

These aspects were not themselves the subject of the Transmission Pricing Review.

The Congestion Management Review however provides the opportunity to address the shortcomings of the current arrangements as identified in our Transmission Pricing submission and as described below.

Efficient Operational Decision Drivers

The existing NEM market dispatch and regional pricing arrangements that provide SRMC incentives upon existing generators to guide efficient production decisions are:

- Marginal loss factors;

- Regional Pricing; and

- Intra-regional congestion management.

The NGF considers that marginal loss factors and regional pricing can provide efficient operational decision drivers however intra-regional congestion management is problematic at present and that it remains to be seen if future congestion support mechanisms will resolve these issues.

Under the current congestion management arrangements congestion is allocated on a "volume" basis rather than "marginal price" basis, therefore if multiple generators are affected, each will incur only a share, rather then the full impact of the congestion. In practice NEMMCO attempts to allocate sharing on the cheapest apparent presented offer of a generator. Whilst this appears efficient, it has the following complications:

- Generators are at liberty to offer any price, and when facing congestion respond by offering at the market floor price. NEMMCO is then required to determine sharing according to other technical parameters that have unpredictable features;

- Some generators are less technically capable of reducing output than others, and as a result receive commensurately less congestion;

- A generator whose output congests or supports an interconnector has distorted incentives, generally an advantage, compared to the generators across the Interconnector;

- No consideration is taken of incumbency in allocating shares, thus a new entrant (inefficiently) locating in a generation rich area will face only a share rather than the full effect. The new-entrant's congestion signal will diminish in proportion to the number of incumbents in the generation rich area.

Thus we cannot presume that the existing intra-regional congestion management provides efficient SRMC impact of congestion upon generators.

Efficient Investment Decision Drivers

The Commission implied in the Transmission Pricing Issues paper that the regulatory test will provide a comparison of two alternative projects and allow an investor to choose the most economically efficient, the one that maximises the NPV, or the least cost where the alternatives provide the same benefits as in the examples provided in the issues paper.

This approach in theory is consistent with providing the appropriate investment signals. The NGF however believes that in practice relying on non firm access and the regulatory test to achieve the objectives of transmission pricing will lead to uncertain outcomes. This is not conducive to encouraging generation investment in an already highly uncertain competitive market, particularly if private-sector investment is to be encouraged.

The most economically efficient investment may not occur for the following reasons;

- New generation investors are not required to conduct a "regulatory test" and demonstrate that their investment is least cost, when compared to a range of alternatives and nor should they. The regulatory test is only applied by TNSPs' to regulated transmission investment based on "committed" (existing) generation projects.

- Investors in new generation will however carry out their own cost benefit analysis in the knowledge that;

  - if the regulatory test for transmission were to be applied before the project is committed, the full cost of the project including fuel delivery fixed and variable costs, power station fixed and variable costs and transmission augmentation costs (to the regional reference node) would be considered to be avoidable when compared to a potential lower cost local generator requiring minimal transmission augmentation

  - if the regulatory test for transmission were to be applied after the project is committed, only the variable costs of the project which include fuel delivery variable costs, power station variable costs and transmission augmentation costs (to the regional reference node) would be considered to be avoidable when compared to a potential lower cost local generator requiring minimal transmission augmentation.

This means that by committing to a project the fixed costs or sunk costs of a remotely located generator are not included in any subsequent application of the regulatory test, thus providing an advantage to the committed remote generator when compared to the cost of a local generator.

Because it is possible for generators to avoid transmission costs or the full impact of the subsequent congestion a project may cause, there is little incentive to locate efficiently to minimise the overall cost of projects, (from fuel source to regional node).

Scope of this review

In our submission of the Transmission Pricing Review we noted that proper signaling of congestion and the provision of locational investment signals to address the issues identified above may require consideration of transmission rights as a key to providing the certainty to encourage efficient investment in generation assets. Alternatively congestion management may offer a solution to address current inefficiencies. The CRA CSP/CSC proposal for congestion management also requires the allocation of transmission capacity between generators which implies a transmission right for generators.

Clarification is sought as to whether the scope of this review includes the consideration of transmission rights over the shared network, generator access network rights or compensation payments from one network user to the other than those required for the implementation of the SCP/CSC proposal. In previous consultations the commission has noted that transmission rights over the shared network will not be addressed, whereas it would appear that such issues could be in scope in the current consultation.

Key issues to be addressed

The NGF considers that the following are the key issues to be addressed:

- Development of a modeling methodology to allow quantification of congestion management costs and benefits;

- A quantification of the current and likely future materiality of congestion, by the application of the methodology;

- Guidelines to address the comparison of the merits of alternative solutions;

- If a CSP/CSC scheme or transmission rights are to be considered, the key issue of principles to guide the allocation of the CSC's must be established and agreed by participants prior to any further consideration of the proposal;

- The development of a staged approach to congestion management as identified in section 5.2 of the issue paper including the definition of the terms "minor or temporary, material, material and enduring" congestion;

- Recognition of existing congestion management problems in the Snowy Region and the rectification of these problems in parallel with the development of a congestion management framework.

If you have any questions in relation to this proposal, please call Roger Oakley on 03 9612 2211 or 0408 512 484.

Yours faithfully

(signed)

John Boshier
Executive Director

1. Do existing constraints have a material effect on the efficiency of the NEM? What is the nature and materiality of these constraints? Why is it that these constraints have not been addressed to date? Are there specific points of congestion that should be addressed in advance of the establishment of a new congestion management regime?

The term "material effect on efficiency" is currently a subjective term, therefore opinions will vary. Statistics are available on the frequency and duration of binding constraints on various transmission elements of the NEM; however these measures can be misleading because for example constraints can be unbound as a result of generator bidding behavior. Also, they do not provide a measure of efficiency impact. There is no benchmark for the measurement of "material" impact apart from the current market benefits limb of the regulatory test, which is a net benefits test. The current version of the test has only been applied informally to the QNI and early indications are that there is a material issue with flow in the direction from Qld to NSW such that an augmentation could be justified by 2009.

There are some other intra regional constraints that could be argued as having an impact on efficient outcomes, such as south-eastern SA, central to north Queensland and central to south Queensland. They have not been addressed because, the Regulatory Test has not been applied and non-transparent network support arrangements are in place in some of these instances.

An improved approach to congestion management is required as it is likely that as demand increases congestion will increase, depending on the location of new generation to meet the demand increase. In a number of cases, transmission solutions may remain uneconomic or infeasible. As a consequence alternatives to the current approach need to be considered and evaluated.

Inter-regional constraints in the Snowy region have come into focus with a partial CSP, CSC trial in place and two recent region boundary change proposals.
The NGF recommends (apart from Snowy region boundaries) that it would create uncertainty if an attempt was made to address specific points of congestion before a congestion management regime was established by this review.

2. Given the development of the NEM and the recommendations of reviews undertaken to date, what are the significant priority issues for this Review?

The NGF considers that the following are the key issues to be addressed:

- Recognition of existing congestion management problems in the Snowy Region and the rectification of these problems in parallel with the development of a congestion management framework;

- Development of a modeling methodology to allow quantification of congestion management costs and benefits,

- A quantification of the current and likely future materiality of congestion, by the application of the methodology,

- Guidelines to address the comparison of the merits of alternative solutions,

- If a CSP/CSC scheme is to be considered the key issue of principles to guide the allocation of the CSC's must be established and agreed by participants prior to any further consideration of the proposal.

- The development of a staged approach to congestion management as identified in section 5.2 of the issue paper including the definition of the terms “minor or temporary, material, material and enduring”.

Congestion management needs to be established in a framework with other regulatory reviews and process such as ANTs.

3. What are the key questions the Commission should seek to examine quantitatively as part of the Review? What key factors should the Commission take into account in this modeling analysis?

The NGF considers that it may be difficult to accurately quantify the relative merits of alternative congestion management proposals in a meaningful way given the broad range of assumptions that will need to be made. Additionally, a historically based modeling analysis is inappropriate due to the commercial incentives on bidding under current market arrangements. A net benefit analysis similar in concept to the Regulatory test may be required. Additionally, the AEMC should consider forward modeling to assess the expected change in Participant’s commercial incentives under new congestion management arrangements. Having said this, the focus should be on removing impediments to market efficiency, avoiding subjective judgments over competitive market outcomes or interactions.

4. Are there any material problems with the ‘option 4’ approach to constraint formulation to managing system security and reliability? How might such problems be addressed while continuing to maintain system security and reliability?

The NGF is of the view that of the options currently available, the Option 4 approach is acceptable and it maximises NEMMCOs’ ability to mange system security.
The problems that arise with:

- Distorted incentives giving rise to inefficient bidding,
- Management of negative settlement residues, and
- Constrained on (and off) generators,

are more likely to be as a consequence of the regional settlement process rather than with option 4 constraints.

5. Are there any other problems, other than constraint formulation, with the management of system security in the context of the current congestion management regime? How might any such problems be addressed?

See answer to 4. Any other problems could be addressed by:

- Development of appropriate locational signals;
- Allocating access to congested lines;
- Operational incentives for TNSPs to minimize congestion.

6. How material are reductions in the dispatch and pricing efficiencies due to binding intraregional constraints under the current arrangements? How can they be quantified?

Both generators and retailers presented information the recent Transmission Revenue Forum in relation to the incidence of constraints. Intra regional constraints can be significant and distortionary. Some may be disguised by generator bidding where the regional settlement process provides distorted incentives.

The impact of intra-regional constraints which do not affect supply to the node (and therefore price at the node) is difficult to measure. It is also difficult to separate these impacts from those of inter-regional constraints, particularly in the case of 'hybrid' constraints.

The AER is attempting to quantify the cost of constraints by calculating TCCs and MCCs as a basis for incentives for TNSPs. The value of these measures is limited as the cost of constraints is being compared to a network with no constraints (ie a theoretical ideal). The AEMC has noted it is unlikely that in an efficient market there would be no constraints. Also the impact on the market as measured by the MCC is potentially overstated.

These measures could potentially be used as indicators as to where a revised constraint management approach could be required.

7. How material are the reductions in dispatch and pricing efficiencies due to the management of negative settlements residues under the current arrangements? How can they be quantified?

Where NEMMCO intervenes to limit negative settlement residues by clamping the impact can be significant. Some participants have expressed concerns that constraint orientation can create dispatch inefficiencies but to a lesser extent.

The AER and NEMMCO should be given the task of assessing the materiality of reductions in dispatch efficiency.

Quantification of productive efficiency changes could be assessed by comparing the actual outcome against a modeled outcome based on actual generator costs. Modeling should be forward looking and consider commercial incentives under the new arrangements.

8. Have the existing arrangements resulted in materially inefficient investments?
Could the existing arrangements result in materially inefficient investments in the future?
What kind of inefficiencies may result?

It is difficult to determine if the current arrangements have resulted in inefficient location of generation as the costs of new investment are not disclosed nor alternatives locations or alternative projects necessarily assessed.
It is possible that inefficient investment could occur if significant constraints are not addressed and poor LRMC locational signals are provided. .

9. How well do existing arrangements provide signals for efficient investment over time and locationally using the least-cost technology—generation, network demand side management or non-electricity alternatives*?*

The issues raised in this question have been addressed in our submission to the transmission pricing issues paper and in the covering letter to this submission.
The regional pricing structure provides appropriate investment signals except where intra-regional congestion results in mis-pricing of generators within a region.

The practice of relying on non firm access and the regulatory test to achieve the objectives of transmission pricing will lead to uncertain outcomes. This is not conducive to encouraging generation investment in an already highly uncertain competitive market, particularly if private-sector investment is to be encouraged.

10. Does the potential to be constrained-off or constrained-on relative to the regional reference price result in material risks for market participants? How are those risks managed?

Yes, being constrained-on or constrained-off does create risks for market participants as there is no compensation under the market rules; unlike an 'intervention' by NEMMCO under the rules (3.9.3) which does provide for compensation.

With respect to the risks of being constrained-on, Clause 3.9.7 of the Rules states the following:

3.9.7 Pricing for constrained-on scheduled generating units

(a) In the event that an *intra-regional network constraint* causes a *scheduled generating unit* to be *constrained-on* in any *dispatch interval*, that *scheduled generating unit* must comply with *dispatch instructions* from *NEMMCO* in accordance with its availability as specified in its *dispatch offer* but may not be taken into account in the determination of the *dispatch price* in that *dispatch interval*.

(b) A *Scheduled Generator* that is *constrained-on* in accordance with clause 3.9.7(a) is not entitled to receive from *NEMMCO* any compensation due to its *dispatch price* being less than its *dispatch offer price*

The original intent of this rule was to avoid market gaming by generators during transmission outages which had occurred in the original England-Wales market. However the market structure in the NEM is quite different to the England-Wales market which had a day-ahead ex-ante price setting mechanism with no revision during actual dispatch.

With the proliferation of constraint equations to manage transmission constraints in the NEM there will be an ever increasing number of constraint equations that contain both negative (constrain-on) and positive terms (constrain-off) terms on the left hand side of the constraint equations. As a consequence, in the case of intra-regional constraints, there will be increasing number of cases of generators being constrained-on or –off and yet receiving no compensation for losses incurred.

For the case of being constrained-on, there is the risk that a generator will be constrained into dispatching output contained in a high price band that is normally reserved for high price events only. Examples are overload price bands on thermal units and running price bands on gas turbines. In these cases the generator is forced to generate in its high price bands but is only paid the regional pool price which must be lower and thus causes a loss.

The only alternative is for the constrained-on generator to bid its plant as commercially unavailable, which could lead NEMMCO to direct the unit to operate. This entitles the generator to direction compensation, but increases intervention in the market and reliance on a mechanism intended as a last resort only.

Consider the case of an interconnector binding. In the importing region of the constraint, generation is dispatched up the merit order and generators there always receive at least their bid price. By contrast with a constrained-on generator, an intra-regional transmission constraint causes them to be similarly dispatched yet in this case there is no compensation for losses incurred.

The NGF therefore argues that there should be market based compensation for a generator that is constrained–on in that the generator should at least be recompensed with its bid price. Due to the increasing complexity and non-predictability of constraint conditions it is no longer valid to argue that generators can game the market under intra-regional congestion.

For the case of being constrained-off, there is the risk that a generator will be constrained to a lower generation level thus missing an opportunity to generate. Such reduced generation will effectively be valued at the pool price and not at the contract price of underlying hedging. If the pool price is high at the time then substantial losses could occur. Generally this risk is managed by reducing contract positions to limit exposure, and caution in trading, both of which inhibit the hedge market and reduce supply. Nevertheless there is still a loss incurred that is not compensated.

The solution is to firstly address congestion issues and risk management measures will follow.

11. Do market participants face problems in managing risk due to the nature of the instruments available, or the liquidity of market for those instruments? If so, how are those problems related to the current approach to congestion management?

The nature of the inter-regional risk management instruments and liquidity do not create problems.

If the intra-regional constraint management issues are addressed the risk management instruments will follow or form part of the solution. At present, congestion risks cannot be hedged.

The problems that arise in managing congestion are due to unscheduled or unusual reductions in capacity of the transmission network and the fact that generators have non firm access to the transmission system.

12. Are there problems in accessing information to support effective risk management in the context of congestion in the NEM? Is the lack of exchange based trading a problem in this context?

Participants in the NEM have access to more information than is publicly available. The NGF considers that liquidity in the NEM is adequate and although liquidity may be less than in other financial markets external facilitation is not supported. It is the NGFs view that the market will deliver appropriate risk management instruments.

13. Does the current design of IRSR units impact the ability of participants to efficiently manage inter-regional price risk?

The SRA design is satisfactory. Problems arise when the nominal rating of the link is reduced, this generally occurs on an infrequent (but sometimes unpredictable) basis. However firming up the SRAs by artificial means in the current market context is not supported as it distorts the allocation of risk among participants.

Transmission firmness can be improved by increasing the performance incentives for TNSPs to align transmission availability to the needs of competitive Market Participants.

14. Has the uncertainty regarding regulatory process and decisions created material risks for participants?

The uncertainty and delay in the regulatory process for changes to the regional structure has created material risks for participants (notably in the Snowy region).
It is time after 5 years of debate to fix the problems - the lack certainty on congestion management creates a risk for incumbents and new investors. The boundary change moratorium has prolonged congestion issues.

15. Do market participants face problems in managing risk due to a lack of transparency associated with the current approach to congestion management? If so, what are the nature and materiality of these problems?

For constraints that are not priced there is no effective constraint management regime under the current framework.

The constraint forecasts provided are low in quality but that may be inevitable given the complexity of constraint formulation.

The level of information provided by NEMMCO allows adequate transparency. A lot of data is provided by NEMMCO but it is mainly relevant in the short term.

16. Are there any additional issues with the current congestion management regime that should be considered as part of the Review? How can the materiality of these concerns be quantified?

Incumbents and new entrants face the risk of having access to the RRN degraded. This is a risk participants have no ability to manage and is due to the fact that generators have non firm access to the transmission system.

The impact of a reduction in capacity can be large but the frequency of events is low and therefore the materiality of the impact is difficult to quantify and may be mitigated in part by the cumulative price threshold.

17. Is this an appropriate characterisation of the current arrangements in the NEM for the purposes of assessing potential improvements to the congestion management regime?

Yes this characterization is appropriate.

18. Is the proposed 'staged approach' to congestion management an appropriate framework? Is it the most effective response to those problems? Is it technically and commercially feasible?

Presupposing that stages are possible for a particular constraint the approach is generally acceptable. It provides a time line and a time frame in which to react.

The approach should also allow for the possibility that some constraints are best met by a constraint management mechanism and never progress to a regional boundary change and in other cases a regional boundary change may be the only practical solution.

19. Has the NEM had material congestion problems which have not been enduring? Is it likely to do so in future?

Yes there have been non-enduring constraints and they are likely to occur in future.
There is considerable uncertainty in predicting the likelihood of constraints that are enduring in nature.

20. Are the costs of an interim congestion regime (discussed in greater detail below) clearly lower than the costs associated with region boundary change?

Yes the implementation costs of a regional boundary change are inherently higher than cost of congestion management because NEMMCO has to modify the dispatch process with implications for participant systems also, whereas in the implementation of a CSP/CSC scheme for example only the settlement process needs to be changed. Ultimately, these solutions may deliver a similar outcome.

21. What triggers should be considered for the introduction of various congestion management tools under a staged approach? Which institutions should be responsible for recommending and approving the introduction of congestion management tools at each stage?

The AEMC should establish the framework with triggers for each stage related to the transaction costs and economic net benefits.

NEMMCO has all the relevant information and conducts the ANTs and so should be responsible for recommending the introduction of a congestion management regime with approval by the AEMC. A coordinated approach is required, consistent across all stages.

22. What role should region boundary changes play in managing congestion, particularly in a staged response? How much emphasis should be placed on that role?

Regional boundary changes may need to be considered as an alternative to constraint management. A constraint management solution may be difficult to implement leaving the only alternative as the regional boundary change. The benefits of would need to exceed the costs. The approach needs to be multi-pronged, rather than simply staged.

23. Is the economic boundary change criterion proposed in the MCE region boundary Rule change proposal consistent with the staged approach to congestion management? What further efficiency gains would be realised from region boundary change, after the introduction of an interim congestion management tool?

There may be no further efficiency gains after the implementation of a constraint management tool however the congestion management tool may be difficult to implement.

24. To what extent will firming-up IRSRs facilitate inter-regional trade? What is the best approach to firming up IRSRs and how would this work?

Refer to earlier comments on question thirteen. The NGF is of the view that firming up of the IRSRs can be achieved through the existing financial market and is best achieved without regulatory intervention.
Creating and aligning the incentives of TNSPs with the rest of the market should improve the firmness of SRAs.

25. Is there a need to review the case for the 'option 4' constraint formulation approach in the context of this Review? If so, what would be advantages and disadvantages of moving away from an 'option 4' approach to constraint formulation?

There's no need to review the case for changing constraint formulation. The issues that remain relate to the settlement process, see our response to questions 4. We see no advantage in moving away from the option 4 approach to constraint formulation if these issues are addressed.

26. What would be the effect of ceasing NEMMCO intervention to manage counter price flows? To what degree does this depend on other factors such as the region boundary criteria and process?

Intervention by NEMMCO to manage counter-price flows is undesirable. Negative settlement residues can be minimised by careful market design thus avoiding the need for intervention. This approach should include development of a generalised approach to negative settlement residues which result from the loop flows and the remote generator case, and this could include;

- a congestion management regime,
- uplift payments, and
- as a last resort intervention by NEMMCO.

27. How should negative settlements residues be funded? Should the current process of offsetting negative residues with positive residues within the current billing week be continued or changed?

The current proposal by NEMMCO to manage negative settlement residues should be modified so that negative settlement residues are accumulated and funded by auction proceeds not by the positive residues. This will preserve the effectiveness of SRA units.

28. Are constrained-on payments an appropriate solution to generators being paid regional reference prices less than what they offer? If so, what principles should apply for determining the size of payments, who should apply them and how should they be funded?

Our answer to question 10 examined why compensation for constrained generation is essential. As a principle the NGF considers that Generators are entitled to be fairly compensated for their output. As a starting point, a generator is entitled to receive its offer price when constrained on. Making the constraint costs explicit will avoid the issues identified in our response to that question and also make the congestion costs explicit so they can be included in TNSP assessments for network augmentation.

Under the current regime, a constrained on generator has to either accept the lower regional price or rebid [1] to force NEMMCO to direct it to generate. Requiring a direction, which was considered a normal response by NECA and NEMMCO in their report of their examination of

[1] This is a good faith rebid because the generator did not offer to provide the generation at the price being paid but rather at a higher price. The rebid allows the generator to gain the fair price for the output.

market directions[2], is clumsy[and may be unpalatable to some generators. It would be simpler to change Rule 3.9.7 to require NEMMCO to pay the generator compensation under Rule 3.15.7 as if it were a direction for energy, since that is the nett effect of the clumsy work-around.

Rule 3.9.7 prevents NEMMCO compensating generators for constrained operation. The Rule was made possible because Rule 5.3 allowed TNSPs to contract with a generator in a load rich area where the transmission is congested and is unable, at certain times, to meet the load and requires a generator to be constrained on. The TNSP is required to apply the regulatory test and select the lowest price option to meet the load (to the required jurisdictional or NEM Reliability Standard, whichever is the highest). These network support agreements have rarely been used, with the North Queensland case cited in the issues paper being the best example[3]. Mandating the use of network support agreements for a defined level of constrained generation could avoid the need for constrained on payments.

Funding of these payments (constrained-on) or network support could accrue to networks since the role being performed is network support in both cases. This would avoid an energy price uplift, which would be unhedgeable and increase retailer risk, therefore increasing customer prices. It would also provide an incentive for TNSPs to use network support agreements more widely, which is potentially more efficient than constraining generators on since the TNSP is then in a position to directly assess the net market benefit. The alternative is to fund uplifts through a market charge that is explicitly passed through to customers.

The AEMC should also consider payments to constrained-off generators as an alternative to a CSC/CSP regime. By paying constrained-off generators the foregone income (assessed by a independent expert using a similar approach to that in 3.15.7A for directions), the value of the constraint is again made apparent and able to be used in the regulatory test. If the generators are made whole, they are also more likely to offer contracts to their full potential, reducing the impact of the congestion. This may be simpler than the CSP/CSC regime if the constraints are of lower materiality. The charges could be allocated in the same way as proposed for constrained on payments.

29. Would the funding of constrained on payments be likely to introduce a material financial risk for participants making the payments? How could this risk be managed?

The risk if any could be hedged through a secondary market or by funding alternative new investment, such as generation, transmission, DSP or non electricity alternatives.

30. Would there be merit in extending the existing NSAs as a congestion management tool in the NEM? If so, how should such arrangements be implemented?

The problem with the current approach to NSA's is that the costs of these agreements are not transparent. NSA's should be tendered in the open market and/or based on market price signals.

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[2] Appendix A to NECA and NEMMCO Final Report - Review of Market Directions. Interestingly, NECA and NEMMCO considered that payments under network support agreements would be the normal compensation for directed on plant.

[3] Somerton Power Station has an arrangement with TRUenergy & AGL to support the network for specific circumstances, which is similar.

Issues to be addressed in expanding the NSA approach are;

- The approach is satisfactory for constrained on payments but problematic for constrained off.
- The TNSP would need to have an incentive to purchase and pay for these services.

A congestion management approach such as a CSP/CSC scheme is possibly superior as an alternative.

31. Should NCAS support contracts be used to enhance transmission network capability? If so, who should offer these contracts?

NCAS support contracts should be extended as a congestion management tool. NEMMCO should arrange NCAS contracts with appropriate transparency.

NEMMCO and the TNSP need to be responsible for providing the service with performance indicators and long term contracts for providers.

32. Is there merit in having TNSPs responsible for procurement of NCAS, rather than NEMMCO, so that NCAS forms a part of the Network Services? If so, how should this be arranged?

Having TNSPs responsible for procurement of NCAS rather than NEMMCO is problematic given distorted TNSP incentives. Arguably NEMMCO is better placed for this role; however the NGF is of the view that it may be worthwhile reconsidering the option of TNSPs contracting for NCAS.

33. What would be the best way of funding NCAS payments and how should this be implemented?

TNSPs should recover these costs from customers through the regulated revenue process.

34. Is the allocation of CSCs a necessary element of a CSP/CSC regime, or would it be practical to introduce CSPs without simultaneously allocating CSCs?

CSPs and CSCs should be implemented together to manage the risk exposure to generators that might otherwise occur with CSPs only. The introduction of CSCs alone merely creates new basis risk for participants, with no tools to manage this exposure.

35. If CSCs are a necessary component, what is the optimal way to allocate CSCs? What effect will this have on the ability to introduce CSPs rapidly and flexibly?

The allocation of CSCs is the biggest issue in their implementation and likely to invoke the greatest range of alternative views amongst market participants. CSCs should preferably be grandfathered rather than auctioned however who the basis on which they are allocated / grandfathered needs to be established. The economic effect and incentives for participants are the same with either approach however auctioning may provide distorted outcomes (ie allocation provides the same incentives without massive wealth transfer between participants). The allocation could be based on a general principle where CSPs are allocated according to historic access to a constraint.

36. Is it important to the design of a congestion management regime whether or not CSCs are firm? If so, what issues should the AEMC consider in reaching a view on the appropriate nature of CSCs?

No. CSCs could be non-firm in the same way SRAs are non-firm. However this needs careful consideration to ensure no additional risk created; i.e. new basis risk.

37. How should the process of region boundary change be coordinated with the allocation of CSCs under a staged approach to congestion management?

Advance notice of a change from a CSP/CSC regime to a regional boundary change would be required to allow participants to manage the potential change in exposures. Transitional measures may also need to be considered to ensure participants are not disadvantaged in moving from a CSC/CSP regime to a regional boundary change.

38. How can the Commission best draw on the partial Snowy CSP/CSC trial to evaluate the costs and benefits of the use of CSP/CSCs? How can the Commission best draw on the Snowy CSP/CSC trial to consider modifications to the proposed design of CSPs and CSCs?

The Snowy trial addressed only the problems arising from the binding intra-regional constraint between Murray and Tumut network nodes. It demonstrated that the mathematics of the process worked. The trial did not address the issue of allocation of CSC's and therefore has limited value as a trial of the concept.

The assessment of what would have happened but for the change requires guessing participant behaviour. The assessment could be based on whether or not the change provided outcomes that more closely achieve the market objective than behaviour before the change.

39. Are there any additional congestion management tools that should be considered as part of this Review? How would these tools be implemented? How would they interact with other aspects of the congestion management regime? What would be the effect of such tools on participant behaviour and market outcomes?

Additional locational signals to new generators (ie new generators pay for the additional capacity required if any to support their investment) should limit the creation of intra regional constraints by efficiently locating new generation. This would be consistent with the market objective. Lack of recognition of current generators access is likely to exacerbate congestion.

NEMMCO should further investigate the costs/benefits of a full network model to determine whether or not this would facilitate implementation of congestion management.

40. Which, if any, of the congestion management issues identified in this paper could be considered on a stand-alone basis? Which issues need to be considered together to ensure a comprehensive and consistent congestion management regime?

Existing and known congestion problems (ie. Snowy Region) should be fixed prior to entering the new congestion management regime; otherwise inefficiencies will be imbedded for another 5 years.

All the congestion management issues need to be considered together (as noted above) to develop a solution integrated with the other relevant aspects of the market and regulated transmission investment.