grid australia
BACKBONE OF THE NEM

14 November 2008

Mr John Tamblyn
Chairman
Australian Energy Market Commission
Level 5, 201 Elizabeth Street
Sydney NSW 2000

By email: submissions@aemc.gov.au

Dear John,

Review of Energy Market Frameworks in Light of Climate Change Policies

Grid Australia makes this submission in response to the AEMC's Scoping Paper released on 10 October 2008 in relation to its Review of Energy Market Frameworks in light of Climate Change Policies. The efficient development of the electricity transmission network is a key element in meeting the objectives of the Carbon Pollution Reduction Scheme (CPRS) and the 20 per cent Renewable Energy Target (expanded RET).

Grid Australia's submission focuses on the issues identified by the AEMC in its Scoping Paper that have direct relevance to the future planning and development of electricity transmission networks. Grid Australia considers that some of these issues are material, and will require further detailed analysis of options for change as the AEMC proceeds with its review.

Grid Australia identifies the following three key issues relating to electricity transmission:

1. Ensuring that geographical extensions of the grid to remote renewable generation are optimally sized;

2. Addressing potential impediments to investment in augmentation of the transmission network to ensure adequate network transfer capability, including any required expansion of interconnector capacity – this should include consideration of the potential to modify existing arrangements to fast-track necessary network investment; and

3. The development of arrangements for inter-regional TUOS charging.

Grid Australia considers that, in reviewing energy market frameworks, the AEMC should do so in a way that is consistent with the sound governance arrangements embodied in the existing regulatory framework, including those recently developed for the National Transmission Planner (NTP).

Grid Australia also considers that the required outcomes can be achieved by implementing relatively minor changes to the existing arrangements, rather than requiring fundamental changes or the creation of new frameworks.

Grid Australia would welcome the opportunity to discuss any aspect of this submission with the Commission or its staff.

Yours sincerely,

Rainer Korte

Rainer Korte
Chairman
Regulatory Managers Group

grid australia
BACKBONE OF THE NEM

Review of Energy Market Frameworks in Light of Climate Change Policies

Response to AEMC Scoping Paper

14 November 2008

Powerlink TransGrid ElectraNet TRANSEND SP AusNet

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1. Introduction

Grid Australia makes this submission in response to the AEMC's Scoping Paper released on 10 October 2008 in relation to its Review of Energy Market Frameworks in light of Climate Change Policies.

Grid Australia comprises ElectraNet Pty Limited, Powerlink Queensland, SP AusNet, Transend Networks Pty Ltd and TransGrid. Collectively, this group owns and operates over 40,000 km of high voltage transmission lines and has assets in service with a current regulatory value in excess of $10 billion. The efficient development of the electricity transmission network is a key element in meeting the objectives of the Carbon Pollution Reduction Scheme (CPRS) and the 20 per cent Renewable Energy Target (expanded RET).

In this submission, Grid Australia focuses on the issues identified by the AEMC in its Scoping Paper that have direct relevance to the future planning and development of electricity transmission networks. Grid Australia considers that some of these issues are material, and will require further detailed analysis of options for change as the AEMC proceeds with this review.

Grid Australia identifies the following three key issues relating to electricity transmission:

1. Ensuring that geographical extensions of the grid to remote renewable generation are optimally sized;

2. Addressing potential impediments to investment in augmentation of the transmission network to ensure adequate grid transfer capability, including any required expansion of interconnector capacity. Appropriate arrangements to address this issue may be transitional rather than making enduring changes to the framework. Specifically, Grid Australia proposes that the AEMC:

   – consider the potential to modify the existing arrangements in order to fast-track necessary grid investment; and

   – review the application of the hurdle in the regulatory test which requires expansions of interconnector capacity to be timed for the year when net market benefits are maximised rather than in the (earlier) year in which the proposed upgrade first demonstrates a net positive market benefit; and

3. The development of arrangements for inter-regional TUOS charging.

Grid Australia notes that the Ministerial Council on Energy (MCE) Terms of Reference for this review directs the AEMC to identify amendments to the current energy market frameworks that may be necessary as a consequence of, or in conjunction with, the implementation of the CPRS and expanded RET. In identifying options for addressing issues raised by these policies, the AEMC is required to have regard to the need for actions to be proportionate as well as to the value of stability and predictability in the energy markets regulatory regime.[1]

Grid Australia considers that, in reviewing energy market frameworks, the AEMC should do so in a way that is consistent with the sound governance arrangements embodied in the existing regulatory framework, including the recently developed governance arrangements for the National Transmission Planner (NTP). Grid Australia also considers that the required outcomes can be achieved by implementing relatively minor changes to the existing arrangements, rather than requiring fundamental changes or the creation of new frameworks. Grid Australia is also of the view that it is appropriate for the AEMC to consider whether changes should be transitional, to manage the process of changeover to the anticipated new generation mix, and what more enduring changes to the frameworks may be required.

Since the AEMC published its Scoping Paper, results of electricity market modelling have been published by both the Garnaut Review[2] and the Commonwealth Treasury.[3] The broad trends apparent in that modelling have informed Grid Australia's perspectives on the potential impacts on transmission networks of the CPRS and the expanded RET.

The remainder of this submission is structured as follows:

- Section 2 sets out, at a high level, the likely implications of both the CPRS and the expanded RET for the development of the electricity transmission network;
- Section 3 addresses Issue 5: Connecting new generators to energy networks;
- Section 4 addresses Issue 6: Augmenting networks and managing congestion; and
- Section 5 highlights that modification to the cost pass-through arrangements in the National Electricity Rules (NER) should also fall within the scope of the AEMC's review.

2. The Potential Impact on Electricity Transmission Networks of Climate Change Policies

Before turning to the specific issues highlighted in the AEMC's Scoping Paper, Grid Australia considers it appropriate to set out some high level considerations in relation

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1 MCE, Terms of Reference – AEMC Review of Energy Market Framework in Light of Climate Change Policies.

2 Ross Garnaut, The Garnaut Climate Change Review Final Report, 2008.

3 Commonwealth Treasury, Australia's Low Pollution Future, The Economics of Climate Change Mitigation, 2008.

to the likely impact of climate change policies on the electricity transmission network and the appropriate policy response.

The electricity transmission network is a key facilitator in meeting the climate change objectives embodied in the CPRS and the expanded RET. Achieving a reduction in greenhouse gas emissions requires a shift to low emission/no emission generation. The CPRS and expanded RET are designed to do this on a 'least cost' basis. Whilst the CPRS modelling indicates a gradual shift from coal-fired to gas-fired and other forms of generation, the modelling for the expanded RET target indicates a requirement for a large amount of new renewable generation capacity, including some capacity which is remote from the existing grid. The appropriate sizing of the transmission network will be important in meeting these objectives.[4]

2.1 Existing Frameworks Appear Likely to Accommodate Gradual Changes Indicated by the CPRS Modelling

The CPRS is expected to result in the increased development of low emission generation, including for example additional gas-fired generation and the increased use of coal seam methane as a fuel for electricity generation. Both the modelling contained in the Garnaut report and the recent Treasury modelling show the expected changes in the generation mix to 2020-2030 to be relatively gradual.

In addition, such developments, although significant in terms of emissions, may not have a significant impact on flow patterns on the grid, the quantum of transmission augmentation required or even the number of connection applications. In some cases, the expansion of these new sources of generation is expected to be located close to existing generation sources, or where new coal-fired generation would otherwise have been developed, and therefore close to the existing and planned transmission network. For example, coal seam methane in Queensland and New South Wales is located in the same place as much of the coal currently used for electricity generation, and where new coal-fired generation would otherwise have been developed.

In the longer term carbon sequestration may enable existing generation sources to remain viable in a high carbon emissions cost environment. This would also result in minimal change to generation sources.

As a result, Grid Australia currently expects that the existing regulatory and market frameworks for transmission planning, investment and new connections will accommodate the changes indicated by the CPRS modelling.

4 Grid Australia notes that in addition to the implications of the CPRS and the expanded RET scheme on the development of the grid, the CPRS in particular is likely to have an impact on the input costs faced by TNSPs. The appropriate treatment of these cost impacts is discussed in section 5.

2.2 Meeting the Expanded RET is Expected to Require Modifications to Current Frameworks

In contrast, the modelling of the expanded RET target (as currently defined) indicates a requirement for an extensive proportion of new generation capacity over the next twelve years to be of a renewable form. There are wind resources close to the existing transmission network; however, it is not clear whether in aggregate these resources would be sufficient to meet the expanded RET, or whether new renewable generation in locations remote from the existing grid will need to be harnessed, thereby requiring geographical extensions of the existing grid.

The expanded RET arrangements are aimed at “least cost” renewable generation, and market participants will therefore decide which new generation is developed. It would be prudent, however, for the AEMC to review the framework applying to transmission investment to ensure that it can accommodate the efficient connection of remote renewable generation, should such generation be required. The increase in renewable generation may also change the pattern of flows on the grid, requiring augmentation of the transmission network both within regions and between regions (i.e. expansion of current interconnector capacity).

In addition, the intermittent nature of wind-powered generation would require the transmission network to accommodate increased degrees of variability in the configuration of generation, as the extent of wind generation increases. Grid Australia notes that the Treasury modelling indicates that wind is expected to be the dominant source of renewable generation in the period to about 2030.

Grid Australia is currently undertaking an indicative quantitative assessment, to better understand the potential impact on the quantum of transmission investment required by the expanded RET target. This assessment builds on work already undertaken by transmission network service providers (TNSPs), and Grid Australia expects that it will be refined over time as the details of the expanded RET scheme (e.g. the pathway to 2020) is made clear. The outcomes of this indicative assessment will be shared with the AEMC, to ensure that its review of the transmission implications of climate change policies proceeds on the basis of a “reasonable best estimate” of the potential magnitudes involved.

2.3 Arrangements should build on current frameworks

Grid Australia considers that modifications to the regulatory and market arrangements to accommodate the CPRS and the expanded RET should build on the current frameworks, rather than require the creation of new frameworks or fundamental departures from the existing framework. Grid Australia considers that this approach is consistent with the MCE Terms of Reference, which refers to the need for actions to be proportionate and points to the value of stability and predictability in the energy markets regulatory regime.[5]

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[5] MCE, Terms of Reference - AEMC Review of Energy Market Framework in Light of Climate Change Policies.

In this regard, Grid Australia considers that some elements of the Garnaut report suggestions in relation to connection of remote renewable generation to represent the creation of new frameworks and/or fundamental departures from the existing framework. Grid Australia considers that the desired outcomes can be achieved by building on existing frameworks.

The recent changes to the NER for transmission regulation and the development of the NTP arrangements incorporate sound governance principles around respective roles, obligations and accountabilities and provide a robust framework going forward. These arrangements have recently been subject to extensive review, both in relation to the Rules applied to the regulation of transmission services and also the arrangements for the NTP and the National Transmission Network Development Plan (NTNDP).

The current frameworks have successfully delivered significant development of the existing transmission networks to accommodate general load growth, new generation sources (e.g. gas, coal seam methane and wind) and the sporadic retirement of existing generation. These frameworks are therefore expected to be able to accommodate the gradual shift in generation mix indicated by the CPRS modelling. However, as noted above, the modelling for the expanded RET indicates the need for some targeted changes to the existing frameworks.

Further, it is possible that some changes to the current frameworks may only be required for a transitional period, to accommodate the changeover to the new generation mix. For example, Garnaut suggests that there would be a “public good” benefit in having stronger interconnection to underpin power system security during the transition from high emission to lower emission sources of generation.

Grid Australia considers that there are two specific changes to the existing arrangements which merit further analysis by the AEMC - the adoption of ‘fast-track’ arrangements for transmission augmentations (discussed in section 4.2) and allowing interconnector expansions to proceed at the time at which they first have a positive net market benefit under the regulatory test/ RIT-T (discussed in section 4.6). The AEMC should also consider whether these should be transitional.

Other modifications may need to be more enduring, such as introducing arrangements to ensure the optimal sizing of grid extensions to remote locations (discussed in section 3.2).

Finally, Grid Australia notes that the MCE has indicated that the AEMC’s review is not to assess the merits of the policy design of the CPRS or the expanded RET.[6] Grid Australia observes that the most significant implications for the electricity transmission networks appear to be driven by the expanded RET, and the likely penalties for retailers under the scheme for failure to redeem sufficient Renewable Energy Certificates (RECs). This would in effect impose a cap on the price at which RECs can be traded (and the revenue that renewable generators can earn from creating RECs).

[6] AEMC Scoping Paper, p.2.

3. Issue 5: Connecting New Generators to Energy Networks

As noted by the AEMC, the current frameworks for connecting new generators in the National Electricity Market (NEM) and the Wholesale Electricity Market (WEM) are based on bilateral negotiation between the generators seeking connection and the TNSP.

The particular concerns raised in the Scoping Paper in relation to connections are that:

1. An increase in the number of connection applications may lead to delays in processing; and

2. Where there is a need for extension of the existing network to connect generators in remote locations, individual bilateral negotiations may not result in extensions being optimally sized, and could result in a 'first mover' disadvantage for generators in a new location.

The timeframe specified for the expanded RET means that there may well be an increase in the volume of connection applications over a short period of time. In addition, if meeting the RET requires the extension of the existing transmission network to accommodate additional renewable generation in remote locations (e.g. wind-farms in the Eyre Peninsula or geothermal generation in the Cooper Basin), then ensuring that these extensions are optimally sized and addressing the first mover problem become important. As discussed in section 2, Grid Australia is currently undertaking analysis to identify the likely extent of network extensions implied by the expanded RET. This analysis will better inform its view as to the materiality of this issue.

Grid Australia does not expect these issues to be material in the case of the CPRS.

The remainder of this section considers each of the above concerns in turn.

3.1 Ability to Process a Large Number of Connection Applications

Grid Australia considers that, based on experience to date, the current bilateral negotiation process for connections is unlikely to require substantial modification to address an increase in the volume of connection applications. However, Grid Australia notes that the complexity of processing a large number of connection applications in a timely fashion has been an issue in a number of overseas jurisdictions, following the introduction of renewable energy targets. It also appears likely that, going forward, the size of generators seeking connection may fall, as wind-generators tend to be of a smaller scale than traditional thermal generators. Therefore, ,it would be prudent for the AEMC to consider whether process changes would improve the efficiency of the current arrangements, given the potential for an increased number of smaller sized connection facilities.

In California the Federal Energy Regulatory Commission (FERC) approved reforms aimed at improving the efficiency of the connection application process[7]. These changes will affect connection requests by large generators (>20 MW). Particular elements of the new policy that appear relevant in terms of addressing the concerns raised by the AEMC are:

- The adoption of a group study approach (the so-called 'clustering approach') by which potential projects with related system impacts are grouped, as opposed to studying each project serially (according to the assigned queue position as it is received);
- Accelerating and increasing developers' commitment to ensure the viability of the projects associated with the connection requests;
- Increasing the financial commitment necessary for project developers to enter the queue (the initial deposit will increase from US$10,000 to US$250,000[8] for generators above 20 MW and for generators below 20 MW the deposit increases to US$100,000); and
- Eliminating the possibility of reassessments after completion of the connection study.[9]

The 'clustering' approach allows for the grouping together of different connection applications where the different generators are expected to affect one another. Two 'cluster windows' of four months duration each are opened, during which time connection requests are accepted.

Grid Australia considers that there may be merit in providing for a similar clustering approach in Australia. Enabling the consideration of applications in clusters has advantages from a network planning perspective, as well as on an efficiency and timeliness basis. The potential complex interactions between numerous generator connections could then be studied as a single scenario. Providing for set "application windows" would also deliver benefits in terms of streamlining the timing of connection applications.

Currently the ability of TNSPs to consider connection applications on a grouped or clustered basis is limited by provisions in the NER clause 5.3.8 that prevent disclosure by the TNSP of connection application information. Whilst TNSPs have always sought to

7 FERC, Generation Interconnection Process Reform (GIPR), September 26, 2008.

8 If the developer cannot demonstrate site exclusivity at the time of the connection request, an additional deposit amount of US$250,000 is required.

9 Under the previous connection procedures, there was a high potential for redoing the study at any time. If one project in the connection queue dropped out, the change could impact other projects in line, thereby forcing the California Independent System Operator (ISO) to reassess the affected projects.

consider all related applications when designing network connections, the confidentiality requirement can make this more challenging, and is likely to inhibit progress where there are large numbers of smaller generators, as expected under the expanded RET.

Grid Australia will separately submit a Rule Change Proposal to the AEMC to amend the provisions under the NER clause 5.3.8. As noted above, transparency would facilitate the consideration of applications by the TNSPs in "clusters", which would improve both the efficiency and the timeliness of the application process. Grid Australia also considers that making key features of connection applications public would provide a greater degree of transparency to the market in relation to future transmission developments. Such public information could be limited to disclosure of the location of the facility and proposed generator size, and would not reveal any commercial information (including the name of the connection applicant). Grid Australia notes that other jurisdictions overseas currently provide this level of public disclosure for connection applications.

Grid Australia recommends that the AEMC consider this forthcoming Rule Change Proposal separately from the current review process, so that the rule change could be implemented prior to completion of the AEMC's review of energy market frameworks in light of climate change. This would allow the AEMC to better understand the current state of play in each jurisdiction in relation to the location and size of connection application facilities received, and would therefore better inform the current review.

3.2 Ensuring that Network Extension to Remote Renewable Generation is of an Optimal Size

The second concern raised by the AEMC in its Scoping Paper relates to ensuring that any geographical extension of the transmission network required to connect remote renewable generation sites is appropriately sized.

As discussed in section 2.2, it is not clear whether it will be necessary to undertake geographical extensions of the existing transmission network to connect renewable generation in more remote locations to meet the expanded RET (e.g. wind generation in the Eyre Peninsula in South Australia or geothermal generation in the Cooper Basin). From an overall market efficiency perspective, any expansion of the transmission network to these locations should be sized optimally, taking into account the potential for several competing generators to, over time, locate in these remote areas.

Under current arrangements, the cost of any geographical extension of the network is met by the connecting generator. There are significant economies of scale associated with transmission investment. As a result, a generator is likely to be better off (i.e. it will face lower expansion costs) if it can share the cost of any required extension with other generators that may later utilise the extension. However, this may represent a 'first mover hurdle' for the initial generator, as it must bear the financing costs associated with an extension sized above its own requirements, together with the risk that additional generators do not, in the end, locate in that area.

In the face of this risk and the upfront financing costs associated with a large scale investment, the generator may decide to invest in a transmission extension that is sub-optimal from the point of view of the market as a whole. The incentives for the generator to finance the investment will also depend critically on the design of the expanded RET scheme, and in particular, whether the value of the RECs that renewable generators receive are effectively capped (which currently appears likely) and, if so, at what level.

Grid Australia considers that there may be a need to modify the existing arrangements, to the extent that geographical extensions of the transmission network are required to connect new remote generation as a consequence of the new climate change policies (particularly the expanded RET). Such modifications may need to be enduring rather than transitional. Two potential options for addressing the 'optimal sizing' of investment for extensions to the grid are set out below.

3.2.1 Market-led Approach

One approach would be to rely on the market to determine the appropriate size of the network extension. Under this approach, generators would themselves get together and form a coalition to finance the extension of the network. Alternatively a single generator may proceed with the extension, and decide to take on the risk that others will later utilise the link. As noted above, the extent to which generators will have this incentive depends crucially on the design of the expanded RET scheme and, in particular, whether the value of the RECs that renewable generators receive is capped and, if so, at what level.

This market-led approach could potentially be facilitated by TNSPs conducting an 'open season' for new network extensions, in which the TNSP provides the opportunity for other generators to also submit an application, in areas where an expansion application has been received and there appears to be potential for additional future generation. Under this approach, TNSPs would only build capacity to meet committed applications. Such an approach would require the current provisions in the NER clause 5.3.8 that makes connection application information confidential to be amended, as discussed earlier.

Open season processes are common in gas markets overseas, and are used to ensure that new capacity is sized appropriately. A key aspect of such processes, however, is the financial commitment that prospective customers are required to make. As a result, it is these parties that bear the risk if they later decide not to develop the generation facility and do not need to use the capacity.

However, there may be practical difficulties with such a market-led approach. Generators are likely to be at different stages of their project development. Consequently, getting a financial commitment from all potentially interested parties at the same time is likely to prove difficult. The more parties that are involved in negotiations, the more difficult those negotiations are likely to be.

In New South Wales, there are established procedures for extending the network to rural customers and the capital contributions made by those customers.[10] In particular, the

[10] Independent Pricing and Regulatory Tribunal, *Capital Contributions and Repayments for Connections to Electricity Distribution Networks In New South Wales*, Final Report, April 2002.

initial customers fund the extension, but there are pre-established reimbursement provisions where that extension is later used by others. These provisions are administered by the relevant distributor. Such an approach could help in addressing the issue of how the initial generator may in practice recover the costs of financing an extension of the transmission network that is sized to accommodate others. However, as discussed above, the financing of this additional capacity and the risks it implies for the initial generator may result in an insurmountable hurdle to such extensions.

3.2.2 Underwriting Additional Capacity through Regulated Charges

A second alternative would be for the foundation generators to fund the initial development of the extension, up to the capacity they require for their own generation development, and for the cost of any additional capacity over and above this level to be initially underwritten by all customers through regulated transmission charges. As new generators located in that area, those new generators would bear a proportionate share of these charges, and the amount underwritten by all customers would fall commensurately.

There is a precedent for such an approach, again in California. The FERC conditionally accepted a proposal which will enable extensions from the main grid to locations that have been identified as suitable locations for the development of renewable generation, to be sized at a capacity which is *above* the capacity that is covered by contracts with generators.[11] The cost of the additional proportion of the development would initially to be borne by all customers.[12] As renewable generators subsequently enter that area and utilise the capacity they would be charged a proportion of the cost of the capacity, and the amount recovered from all customers would fall correspondingly. The proposal is termed the Location Constrained Resource Interconnection (LCRI) provisions.

Relevant features of the LCRI provisions are:

- The provisions cover grid extensions to areas certified by the California Resource Commission and the California Energy Commission as 'Energy Resource Areas';
- To be eligible, at least 25% of the proposed capacity must be covered by connection agreements and the transmission owner must demonstrate that overall there is interest by generators in relation to at least 60% of total capacity. These provisions are intended to limit the risk of stranding faced by customers in underwriting the additional capacity; and

[11] Federal Energy Regulatory Commission, ER08-140-000, December 21, 2007. FERC conditionally accepted the CAISO tariff language but requested further revisions. The CAISO drafted the tariff changes in August 2008. These latest changes have not yet been filed so the LCRI approach is not yet in effect. However Grid Australia understands that the approach could be in place by early 2009.

[12] California ISO press release *"Greening the Grid Gets Green Light: California ISO Board of Governors Approves Formal Changes Enabling Renewable Power to Link to Grid."* 17 October 2007.

- There is a cap on the overall extent of investment covered by the LCRI provisions of 15% of the aggregate of net investment in all high voltage transmission facilities. This cap is intended to limit the price impact of the provisions to customers[13].

In conditionally approving these provisions, the FERC noted that:

> 'After careful examination of the various process and procedures proposed by the CAISO, we find that the LCRI proposal contains multiple mechanisms that work in concert to promote investment in needed infrastructure, assist the state in meeting its [Renewables Portfolio Standard] goals, provide an appropriate signal to LCRI generator development, and balance the risk of stranded cost and impact to ratepayers.'[14]

The above approach could be adapted and applied to geographical extensions of the electricity transmission networks in the NEM to connect remote renewable generators. In doing so it would be important to ensure that:

- The arrangements sit within the existing institutional and regulatory arrangements, and in particular the sound governance arrangements established following the AEMC's recent review of the NTP that clearly define the allocation of roles, obligations and accountabilities between the NTP and TNSPs;

- The arrangements also fit within the existing regulatory frameworks as much as possible, to ensure that changes are proportionate; and

- The approach minimises distortions in the market (e.g. it should not disadvantage existing generators or "non-remote" new renewable generators).

In relation to the first of these points, Grid Australia notes that the current governance arrangements encourage the focus of the NTP to be on longer-term, strategic assessments of potential developments, whilst TNSPs remain responsible for the detailed planning surrounding their investment decisions, making the investment decisions, managing the funding thereof, transmission pricing and collection of transmission charges.

Appendix A sets out a preliminary model that Grid Australia considers is consistent with the above principles.

If this approach was adopted, transmission extensions would be sized at the "optimal" level from a market perspective. Foundation generators would also no longer face a first mover disadvantage in locating in a new remote area, and would pay for only the

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13 It is proposed that demonstrations of interest can include (i) executing a power purchase agreement of at least 5 years duration; (ii) being in the CAISO's connection application queue and having paid the relevant deposits; (iii) paying a cash deposit of 5% of the generator's pro rata share of the capital cost of the proposed LCRI facility. See FERC ER08-140-000 para (11).

14 FERC, ER08-140-000 para (391).

proportion of the new investment they required. Customers as a whole would bear the risk that future generation does not develop in that area and that the additional capacity is not required in the end. However, it would be possible to limit this risk (see Appendix A). This "partial customer pays" approach can be justified on the basis that it is a necessary flow-on from the public policy (expanded RET), which necessarily imposes a cost on customers (in exchange for an environmental benefit).

3.3 Questions Raised by the AEMC

This section responds to specific questions raised by the AEMC in the Scoping Paper, drawing on the discussion presented above.

12. How material are the risks of decision-making being 'skewed' because of differences in connection regimes between electricity and gas.

Grid Australia is not convinced that there are material risks of decision-making being skewed because of differences in the connection regimes between electricity and gas. The regimes are not in practice very different, with both relying on bilateral negotiations.

However, it should be noted that processing connections to electricity networks is more technically complex than connections to gas networks. This is exemplified by the requirements to ensure that generators (and customers) seeking connection meet the performance standards necessary to enable secure operation of the interconnected system. This process is technically sophisticated, often requiring extensive power system modelling. Grid Australia is not aware of similar issues associated with connection to gas networks.

It is this added complexity that may be more easily addressed if generator connection assessments could be processed as clusters as proposed earlier in this submission.

13. How large is the co-ordination problem for new connections? How material are the inefficiencies from continuing with an approach based on bilateral negotiation?

Grid Australia considers that the current bilateral negotiation process for connections is unlikely to require substantial modification to address an increase in the volume of connection applications. However, Grid Australia considers that it would be prudent for the AEMC to consider incremental changes to the current arrangements to facilitate the consideration of an increased number and associated complexity of processing of smaller sized connection applications.

Grid Australia sees potential benefits in the adoption of a 'clustering' approach to considering connection applications. To facilitate such an approach, the current provisions in the NER clause 5.3.8 (which make connection application information confidential and prevent the TNSP from disclosing that information) would need to be amended.

14. Are the rules for allocating costs and risks for new connections a barrier to entry, and why?

The economies of scale associated with transmission development mean that the costs associated with network extensions are likely to be significant, if extensions cannot be sized for potential future use by others. This may represent a 'first mover hurdle' for the initial generator, as it must be able to bear the financing costs associated with an extension sized above its own requirements, and the risk that additional generators do not locate in that area.

The extent to which the financing costs associated with new extensions present a barrier to entry will also depend on expectations as to the level of future prices associated with the RECs earned by renewable generation. A 'soft' penalty for not meeting REC obligations lowers the financial benefits to generators from investing in renewable sources, and therefore their willingness and ability to fund substantial extensions of the transmission network.

Grid Australia is currently undertaking a quantitative analysis to provide an order of magnitude appreciation of the materiality of this issue, and will share its findings with the AEMC once available.

An alternative model presented in section 3.2.2 (and Appendix A) would result in foundation generators funding network extensions up to the level of their own requirements. Where the optimal size of the extension from an overall market perspective is considered to be above this, the costs of the additional capacity would initially be funded by all customers through regulated transmission charges. Over time, as generators signed up for the new capacity they would then pay their proportionate share of the extension costs, and the amount recovered from customers would fall.

4. Issue 6: Augmenting Networks and Managing Congestion

The AEMC Scoping Paper notes that: '[t]he capability of the shared network is [..] an important determinant of market outcomes.'[15]

The second key implication of the new climate change policies for the development of the electricity transmission network is the extent to which augmentation of the existing transmission networks may be needed. Such augmentation may relate to either:

1. The existing transmission network within each jurisdiction to accommodate any change in generation flows resulting from a change in the location and cost structure of the generation sector, as well as to address technical issues, including the impact of an increase in intermittent generation on the operation and control of the power system and maintaining power system security; and

2. Interconnectors to support any increase in flows between regions, to the extent that changed location of generation causes the pattern of imports and exports in each region to change.

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[15] AEMC Scoping Paper, p.30.

Grid Australia is currently undertaking a quantitative assessment of the materiality of the changes that may result, and the implications for the magnitude of network augmentation that may be required.

4.1 Current Arrangements

Major transmission line augmentations typically take between 4-7 years to develop. Before construction can commence the TNSP needs to complete both regulatory approval processes and also environmental and other site approval processes, including an Environmental Impact Statement (EIS). The EIS and site approval processes are major contributors to the long lead times involved.

In relation to regulatory approvals, augmentations to the shared network generally fall under the scope of "prescribed transmission services". Almost all significant augmentations of the transmission network to provide prescribed services are subject to the regulatory test.[16] The regulatory test is a form of cost-benefit analysis that assesses the net benefit (or net cost) of a particular transmission augmentation against alternative options.

The regulatory test is expected to be replaced by the RIT-T.[17] Under the RIT-T:

- Where network augmentations are driven principally by the need to meet reliability standards,[18] augmentations satisfy the RIT-T if they have a lower net cost than alternative options. Importantly, the overall net cost may still be positive. That is, there is assumed to be no 'do nothing' option for these augmentations.
- All other network augmentations only satisfy the RIT-T if they have a greater net market benefit compared to alternative options (including the 'do nothing' option). As a result, an option must have a positive net market benefit if it passes the RIT-T (since it must be better than doing nothing).

As a result, TNSPs face two separate drivers in relation to augmentation of their transmission networks:

- The mandatory reliability obligations they face; and
- A commercial driver reflecting the rate of return the TNSP earns on its asset base.

16 NER 5.6.2A(b)(5) (new small transmission network asset) and NER 5.6.6(4) (new large transmission network asset).

17 AEMC, National Transmission Planning Arrangements, Final Report to the MCE, 30 June 2008.

18 Specifically a need 'to meet the service standards linked to the technical requirements of schedule 5.1 of the NER or in applicable regulatory instruments.'

In assessing the forecast of expenditure submitted by the TNSP in a Revenue Proposal, the Australian Energy Regulator (AER) must accept the expenditure forecast where it is satisfied that the forecast reasonably reflects the criteria set out in the NER clauses 6A.6.6 (for operating expenditure) and 6A.6.7 (for capital expenditure).

Grid Australia considers that the current regulatory arrangements generally support TNSPs augmenting their networks to address any capacity constraint issues arising from both the CPRS and the expanded RET. The existing contingent project mechanism in the NER provides a possible means to manage any significant uncertainty about the timing of new network augmentations, including those required to accommodate changing generation patterns.

However, there may need to be some changes to the existing arrangements to facilitate the shift to new patterns of generation within the required timeframes. In particular, it may be appropriate to:

- Utilise existing fast-track arrangements to ensure that transmission augmentations can be completed in a timely manner (discussed in section 4.2); and

- Allow interconnector projects to proceed in the year in which the regulatory test (or RIT-T) indicates that they may first have a positive net market benefit, rather than in the year in which the net market benefit is maximised (discussed in section 4.6).

One or both of the above may be transitional requirements.

In addition, Grid Australia considers that it would be appropriate to modify the current frameworks to:

- Reflect the climate change policies in the assessment criteria set out in clauses 6A.6.6 and 6A.6.7 of the NER, in relation to the AER's assessment of a TNSP's expenditure forecasts (discussed in section 4.4); and

- Set out the basis for inter-regional charging (discussed in section 4.7).

These issues are discussed further below.

4.2 Fast Track Arrangements May Need to be Applied to Network Augmentation

The expanded RET target is to be achieved by 2020, in just over eleven years time. Transmission investments typically have lead-times of 4-7 years. As noted above, there are extensive EIS processes and other site approval processes associated with major transmission developments, particularly transmission line developments.

Under the current regulatory test arrangements and the proposed RIT-T, additional investment in network augmentation to meet the RET needs to be justified on the basis of having a positive net market benefit. This in turn has some important implications.

The first is that the level of the weighted average cost of capital (WACC) received by the TNSP needs to provide sufficient commercial drivers for the investment. Grid Australia notes that the AER is currently undertaking a review of the WACC parameters, in line with the current framework in the NER for determining WACC, established by the AEMC. It is important that the outcome of that review results in a WACC which adequately reflects the current environment, including capital market conditions in relation to the cost of funding. In its submission to the AER's review, Grid Australia highlighted the importance of ensuring that the investment climate provides adequate investment incentives to install optimal levels of capacity to support expansion of the grid in light of climate change policies and to allow flexibility in the amount of interstate electricity trade.[19]

The second implication reflects the fact that augmentations justified on the basis of an overall net market benefit (rather than the need to meet reliability obligations) are typically more likely to attract disputes. Although an augmentation may have an overall positive net market benefit, where it changes the pattern of generation flows means that there will be both winners and losers resulting from the augmentation. Generators (or other parties) that stand to lose from the augmentation have a commercial incentive to appeal the process, extending the timeframe required to pursue such augmentations.

Because the cost/ benefits assessment is based on market simulations, which in turn, are based on a series of assumptions, including generator bidding behaviour, there are many opportunities for a potential "loser" to dispute the analysis. In the case of the expanded RET target, the modelling indicates a fundamental shift for the sources of generation, and the potential for geothermal and wind generation to be pursued as alternatives. Any proposed augmentation of the network to support the development of renewable generation is more likely to result in a protracted approval process, with an even wider than normal range of disputable assumptions.[20]

Grid Australia notes that the new arrangements for the NTP and the NTNDP provide an avenue that may assist in reducing the level of dispute in relation to network augmentations which are assessed as having a net market benefit. In particular, the NTP is expected under the NTNDP to flag options (at a conceptual level) for the development of the transmission network taking into account future generation developments (including renewable generation). The NTP is also expected to develop a view of the key assumptions that would feed into the RIT-T assessment (including the appropriate market development scenarios). The NTP's involvement (in the manner set out by the recent AEMC review) provides a NEM wide platform for the assessment.

Individual TNSPs are then able to point to the conceptual options flagged by the NTP in developing proposals to augment their networks.

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[19] Grid Australia, Review of the WACC parameters for Electricity Transmission and Distribution, Response to AER Issues Paper, 24 September 2008, p.8.

[20] Experience of the major market benefit augmentation proposal to date in the NEM (the SNI interconnector proposal by TransGrid to augment the transmission capacity between South Australia and Victoria) highlights the extent of the delay and the costs that a TNSP may incur in pursuing a market benefit augmentation that may ultimately end up not being constructed.

The involvement of the NTP in the manner outlined above has some potential to limit the debate around the appropriateness of a TNSP's proposals. Having the NTP provide input in relation to key assumptions may assist in managing the debate around the appropriateness of the TNSP's analysis, and thus in containing challenges to the RIT-T assessment. It is therefore important that the NTP undertakes both of these functions in a thorough and defensible manner.

Given the long lead times for transmission investment, and the potential for drawn-out disputes in relation to both the regulatory approvals process and also the environmental and site approval processes, it may be appropriate to consider the use of existing legislative arrangements in each jurisdiction for fast-tracking critical infrastructure projects. For example, in New South Wales the Critical Infrastructure Projects Act makes special provision for critical infrastructure projects, which are defined to be projects which are essential for the state for economic, social or environmental reasons. In particular, an objector to a critical infrastructure project is not, without the approval of the minister, able to bring proceedings which will delay the project, including injunctions.

The use of such fast track provisions for transmission augmentation could represent a transitional arrangement to assist in meeting the timeframes required by the climate change policies (and specifically the expanded RET).

The approach may also require transitional restrictions on the dispute provisions in the NER.

Grid Australia notes that Germany has introduced a law to fast-track infrastructure investments, specifically associated with the development of renewable generation. The Law for the Acceleration of Infrastructure Planning [21] came into force on 17 December 2006. The Law is aimed at shortening the planning period for construction of new lines. It amends the rules on the permission proceedings that exist in the Energy Law, notably the form of the hearing procedures. Article 43 of the Energy Law has been amended such that, for instance, the public and associations can now only make objections or statements one month after submission of the full plan at the latest.

4.3 Certainty in Relation to Investment

In addition to ensuring that the WACC is set at a level to provide sufficient commercial incentives for transmission investment, it is important that there is also sufficient certainty and stability in relation to the regulatory treatment of transmission investments, to allow TNSPs a reasonable opportunity for the recovery of efficient costs.

In particular, the AEMC should make it clear that there should be no risk of stranding associated with transmission investment that has entered the RAB, if subsequently there is a change in government policy that results in such investment being underutilised. This is consistent with the current NER provisions.

[21] Gesetz zur Beschleunigung von Planungsverfahren für Infrastrukturvorhaben.

In particular, transmission investments that are undertaken to facilitate achievement of the expanded RET by 2020, and which pass the regulatory test or RIT-T (as appropriate) and are included in a TNSP's regulatory asset base (RAB) should not be at risk of stranding as a result of the planned phase-out of the RET between 2020 and 2030.

As has been highlighted in this submission, to the extent that there are significant changes going forward in the location of new generation and the pattern of flows on the existing network, which in turn drive substantial investment in the transmission network, these appear likely to be driven by the expanded RET rather than the CPRS. Future changes to the RET could therefore have a substantial impact on the utilisation of those assets.

As noted above, the proposed approach to asset stranding risk is consistent with the current NER provisions and recognises that TNSPs make investments to satisfy public policy requirements (for example mandated network reliability standards).

Grid Australia also notes the potential for the utilisation of existing transmission assets that carry the output of current coal-fired generators to load centres to fall as a result of the new environmental policies. To the extent that this potential is realised, and consistent with the above approach to asset stranding risk, these assets should not be removed from the TNSP's regulatory asset base.

4.4 The AER Should be Required to have regard to Climate Change Policies in Assessing a TNSP's Expenditure

As noted above, in assessing the forecast of expenditure submitted by the TNSP as part of its revenue proposal, the AER must accept the expenditure forecast where it is satisfied that the forecast reasonably reflects the criteria set out in NER clauses 6A.6.6 (for operating expenditure) and 6A.6.7 (for capital expenditure).

Grid Australia considers that it would be appropriate for the criteria in the above clauses to be extended to also refer to the CPRS and expanded RET, given the key role of the electricity transmission grid in facilitating the achievement of the objectives under these policies.

4.5 The RIT-T Allows for Incorporation of CPRS and RET

The current regulatory test and the proposed RIT-T both allow for the costs and benefits of changes in carbon emissions to be incorporated into the analysis, once there is a price in place under the CPRS.[22] Similarly, once there is a price for RECs under the expanded RET, this can also be incorporated into the analysis (and will have the impact of reducing

[22] Regulatory Test Version 3 Clause (10) excludes costs or benefits that cannot be measured as a cost or benefit to producers, distributors or consumers of electricity. The intention of this clause is to exclude externalities. The previous version of the regulatory test (version 2 clause (8)) explicitly referred to factors that couldn't be measured 'in terms of financial transactions in the market.' The AEMC's proposed draft rule contains a similar provision: 5.6.5B (c)(9).

the effective per MWh cost of renewable generation). The current regulatory test also requires that sensitivity analysis include 'market based regulatory instruments that may be used to address greenhouse and environmental issues.'[23]

As a result, it does not appear necessary to make any modification to the existing regulatory test or RIT-T arrangements to facilitate transmission investment in response to the CPRS and RET. However, the NTP could play an important role in setting out the appropriate assumptions to be adopted in relation to the future price of carbon permits and RECs.

4.6 Public benefit from increasing interconnector capacity

The Garnaut report identified that:

> 'While it may seem inefficient to have permanent abundant excess capacity in the interconnectors between regions, in the world of structural change that Australia is entering, generation cost differences will exceed the distribution losses and infrastructure costs for high levels of capacity. [..]

Having excess capacity in interconnectors provides additional security for the system as a whole in light of the pressures likely to arise from both climate change and an emissions trading scheme.'[24]

Grid Australia's interpretation of the above statements is that Professor Garnaut considers that there would be a benefit in expanding interconnector capacity in the NEM, as an "insurance policy" in the event that there is a supply-demand imbalance, during the transition from high emission to lower emission sources of generation.

The use of existing legislative "fast track" provisions (discussed in section 4.2) would be one means of ensuring that investment in interconnector capacity can proceed in a time frame consistent with policy imperatives.

In addition, Grid Australia notes that under the regulatory test (and the proposed RIT-T) it is necessary to demonstrate that the timing of the additional interconnector capacity is the timing that maximises the net benefit to the market. That is, it is possible for an interconnector expansion to have a positive net benefit in earlier years, but still not to be deemed to pass the regulatory test (or RIT-T) if the benefit would be maximised by deferring the augmentation to a later year. This results in the development of the interconnector needing to 'wait'.

This situation was recently demonstrated in the evaluation of a potential upgrade to the QNI. The study showed that the year in which net benefits were maximised would be 2015/16, whereas positive net benefits were evident much earlier (2011/12), a result

23 Regulatory Test Version 3 Clause (24)(j).

24 The Garnaut Climate Change Review, Final Report, p.447.

confirmed by NEMMCO's 2008 ANTS. As a consequence of the regulatory test requirement, the upgrade has been put on hold. In contrast, generation development, which is not subject to regulation and hence does not need to meet the same criteria, tends to be developed in the year in which the developer first perceives there is a net benefit.

To the extent that expansion of interconnector capacity is seen to provide benefits in terms of additional security to the market during the period of transition to the new carbon constrained environment, and to facilitate meeting the expanded RET, Grid Australia considers that the AEMC should consider the merits of allowing investment in relation to the expansion of interconnector capacity to proceed in the year in which the regulatory test (or RIT-T) indicates that such expansion first has a positive net market benefit, rather than in the year in which the net market benefit is maximised. Such a change is likely to have the impact of bringing forward the timing of interconnector development. The AEMC needs to also consider whether such an approach should be a transitional measure.

4.7 Arrangements for Inter-Regional Charging

Currently customers in each jurisdiction pay transmission use of system (TUOS) charges relating to the assets of the TNSP in that jurisdiction. The NER does not explicitly provide for the transfer of TUOS charges across regions.

Grid Australia notes that the MCE has now requested that the AEMC include the issue of inter-regional charging as part of the AMEC's current review.

The AEMC identified this issue in its earlier review of the National Transmission Planning arrangements, and set out some alternative options for inter-regional charging.[25] The table below sets out Grid Australia's earlier assessment of each of these proposed options.[26]

[25] AEMC, National Transmission Planning Arrangements, Final Report to MCE, 30 June 2008.

[26] Grid Australia, National Transmission Planning Arrangements, Response to the AEMC Draft Report, 30 May 2008.

Table 4.1: Assessment of Alternative Options for Inter-regional Charging

	Option 1	**Option 2**	**Option 3**	**Option 4**
	Interconnector cost sharing	NEM-wide Interconnector cost sharing	Load Export Charge	NEM-Wide Methodology
Economic efficiency	×	×	✓	✓
Transparency & predictability	?×	?×	?	✓
Good governance and accountability	?✓	?✓	✓	?✓
Minimisation of implementation costs and risks	?✓	?✓	✓	×

Options 1, 2 or 3 are likely to be capable of practical implementation, although options 1 and 2 both raise specific implementation issues, and have the potential to lead to disputes. Option 4 represents the most fundamental change to the current NEM arrangements, and is likely to raise significance implementation issues.

On the basis of the above, Grid Australia indicated a leaning towards Option 3 (Load Export Charge). Compared to the other options proposed, this option appears to be relatively more straightforward to implement.

Grid Australia notes that in its Final Decision, the AEMC also expressed the initial view that the load export charge option (option 3) is the best option.

4.8 Questions Raised by the AEMC

This section responds to specific questions raised by the AEMC in the Scoping Paper, drawing on the discussion presented above.

15. How material are the potential increases in the costs of managing congestion, and why?

Grid Australia considers that this is a key question. In particular, the AEMC's review should be informed by a view as to the likely quantum of network augmentation (both inter-regional interconnectors and intra-regional augmentation) that is required as a result of both the CPRS and the expanded RET. Grid Australia's initial view is that the extent of network augmentation required for the CPRS is likely to be much less than that arising for the expanded RET, given the latter's potential to have a more significant impact on the current level and direction of flows between regions, particularly from "renewable generation rich" regions.

Grid Australia is currently undertaking a 'first-cut' assessment of the likely quantum of transmission investment required under some plausible scenarios, drawing on work that has already been done by TNSPs. Grid Australia will be happy to share the outcome of this analysis with the AEMC once it is completed.

In relation to changes suggested to allow interconnector augmentation to proceed in the year in which the regulatory test (or RIT-T) indicates a positive net market benefit, the results from the Powerlink/TransGrid modelling for QNI foreshadow significant levels of congestion in the years between when the net benefits are first positive, and the year in which an upgrade would proceed, based on the current requirement to maximise market benefits.

16. How material are the risks associated with continuing an 'open access' regime in the NEM?

Grid Australia considers that delivering the required network augmentation implied by the CPRS and the RET can be addressed via incremental changes to the existing arrangements and appropriate transitional arrangements, rather than more fundamental changes to the current regulatory and institutional frameworks. The current frameworks have recently been subject to extensive review and it would be inappropriate for wholesale changes to be made to these regimes at this time.

17. How material are the risks of 'contractual congestion' in gas networks, and how might they be managed?

Grid Australia has not addressed this question, as it is not directly applicable to electricity transmission.

18. How material is the risk of inefficient investment in the shared network, and why?

Grid Australia does not consider that there is a material risk of inefficient investment in the shared network, provided that the level of the WACC applied to transmission networks is set at an appropriate commercial level.

TNSPs already co-ordinate their planning activities. Going forward the NTP and NTNDP are also expected to provide a further national perspective on future developments, through the identification, at a strategic level, of longer term options for development.

There is already provision within the existing regulatory framework for the efficiency of transmission investment to be assessed; i.e. via the cost benefit analysis of alternatives required by the regulatory test (which will be replaced by the RIT-T going forward). There is an important role for the NTP in developing the assumptions that can be used in making RIT-T assessments, in particular the generation development scenarios. Having the NTP providing a high level strategic assessment of potential future developments in both the generation and transmission sectors will provide an additional level of independent input into the RIT-T analysis conducted by TNSPs, which may assist in reducing the scope for disputes, which have the potential to delay transmission augmentation.

If there is a need for substantial augmentation of the transmission network, in particular to meet the expanded RET target by 2020, it may be necessary to adopt fast track provisions for the investment, given the long lead times. Such provisions could represent transitional arrangements to facilitate the changeover to the new low emission environment.

19. How material is the risk of changing loss factors year-on-year?

Grid Australia has not addressed this question, as it is not directly applicable to electricity transmission.

5. Pass-through Arrangements

The focus of many of the questions in the AEMC's Scoping Paper, and the discussion earlier in this response, is on transmission investment that may be required as a result of the new climate change policies.

Grid Australia notes that the new policies may also have implications for the costs faced by TNSPs. For example, there are likely to be significant input cost increases for materials and equipment (steel, plant and station equipment, fuel) due to the impact of the CPRS, although the full extent will depend on the details of the design of the scheme.

The current cost pass-through arrangements do not appear to automatically allow TNSPs to apply for a cost pass-through in relation to these additional costs.

Under the NER a *regulatory change event* is defined as:

> A change in a regulatory obligation or requirement that:
>
> (a) falls within no other category of pass through event: and
>
> (b) occurs during the course of a regulatory control period; and
>
> (c) substantially affects the manner in which the Transmission Network Service Provider provides prescribed transmission services or the Distribution Network Service Provider provides direct control services (as the case requires); and
>
> (d) materially increases or materially decreases the costs of providing those services.

A *regulatory obligation or requirement* is in turn defined in section 2(D) of the National Electricity Law.

Whilst it appears that the CPRS and the expanded RET would fall under the definition of a *regulatory obligation or requirement*, it is not clear that they would fall under the definition of a *regulatory change event,* since although they may affect a TNSP's input costs, they need not result in a change in "the manner in which the TNSP provides prescribed transmission services" (i.e. part (c) of the above definition).

The earlier Department of Climate Change Green Paper noted that:

> ‘Regulatory or contractual impediments to cost pass-through may increase the impact of the scheme on particular firms or industries. [..]
>
> Ideally, there should be no regulatory impediments to the pass-through of reasonable carbon costs.[27]

Grid Australia considers that it would be appropriate for the AEMC to include within the scope of its current review the changes that may be required to the NER to ensure that there are no regulatory impediments to the pass-through of reasonable costs by regulated network businesses.

[27] Department of Climate Change Green Paper, p.430.

Appendix A. A Model for 'Right-sizing' of Geographical Extensions to the Grid

This Appendix presents a potential model for ensuring that extensions to the grid to connect future remote renewable generation are sized optimally, and that the need to extend the grid to remote areas does not become a barrier to the development of generation in those areas.

Grid Australia considers that this model is consistent with the principles set out in section 3.2.2, and in particular that it builds on the current regulatory framework and the existing governance arrangements, roles, obligations and accountabilities for the NTP and TNSPs.

Under the model:

1. The NTP would identify "prospective extension areas", defined as areas remote from the existing grid, where it appears that there is scope for substantial development of renewable generation. This process could sit alongside the development of the NTNDP[28];

2. The NTP would also identify the optimal size of the network extension required to meet the long term future likely capacity of new generation in each area. The NTP would then carry out a cost benefit analysis of the development of extensions to these various "extension areas", and rank them in terms of net benefits;

3. The AEMC or AER would develop a set of "cut-off criteria" which would be applied to this ranked list. The criteria could be as simple as the project having an assessed positive net market benefit;

4. Where a project ranked above the cut-off criteria, it would go into the contingent project list for the relevant TNSP;

5. The TNSP would define the trigger for each project to proceed (subject to approval by the AER), in line with the current process for contingent projects. Such triggers would be expected to relate to signed connection agreements with foundation generators to fund a specified minimum percentage of the new capacity.

6. Once this trigger had been met, the TNSP would undertake the augmentation, subject to an economic analysis confirming that the detailed investment design was optimal.

7. Under this approach, each "foundation generator" would still have a separate bilateral agreement with the TNSP, to cover matters such as commercial bonuses/ penalties for on-time delivery.

8. To the extent that the contributions from generators under bilateral agreements do not recover the full cost of the extension, the remainder would be included in the TNSP's

28 Through the process of preparing the NTNDP, the NTP is already expected to consider likely future generation developments, including the development of renewable generation in response to the expanded RET.

revenue cap (as per the current arrangements for contingent projects) and recovered through charges from all customers.

9. When new generation subsequently located in the same area, it would be charged for the use of its share of the extension under a bilateral agreement with the relevant TNSP, and there would be a corresponding reduction in the remaining costs recovered from customers under the revenue cap.

Under this approach, transmission extensions would be sized at the 'optimal' level from a market perspective and foundation generators would no longer face a first mover disadvantage in locating in a new remote area, and would pay for only the proportion of the new capacity that they required.

Customers as a whole would bear the risk that future generation does not develop in that area and that the additional capacity is not required in the end. This risk would be partly mitigated by (i) the process of having the NTP identify the areas of extension and optimal size of the extension, and ranking the extensions to the prospective areas on a costs/ benefits basis and (ii) by the required triggers for the investment to proceed; i.e. a minimum proportion of the cost of the extension would need to be funded under bilateral agreements with generators.