AER Submission

Review of Energy Market Frameworks in light of Climate Change Policies

Response to AEMC first interim report

23 February 2009

Introduction

The Australian Energy Regulator (AER) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) first interim report for its review of the impacts of the Australian Government's Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (RET) on existing energy market frameworks.

The AER monitors the National Electricity Market (NEM) and is responsible for compliance with and enforcement of the National Electricity Rules (NER) and National Gas Rules. The AER is also responsible for the economic regulation of electricity transmission and distribution services as well as gas transportation services. These roles leave the AER well placed to comment on the performance of Australia's energy markets and also on network issues raised by the introduction of the CPRS and expanded RET.

The AER's submission on the scoping paper noted that Australia's energy market reforms of the past 15 years have been a major success. While issues have emerged recently, our energy markets have generally delivered significant investment and very high reliability. The AER therefore cautioned against fundamental changes to Australia's existing energy market frameworks, such as the introduction of a capacity market. The AER argued that the AEMC's review should be focused on the modifications to existing energy market frameworks required to accommodate the introduction of the CPRS and expanded RET.

The AER notes that since the release of the interim report, there have been reports of the global financial credit crisis worsening and concerns raised regarding the continued reliability of electricity supply in the NEM. The AER considers that these are extraordinary, transitory and uncertain events which are unrelated to the introduction of the CPRS or expanded RET. Given this, the AER would caution against substantially changing energy market frameworks in response to these issues.

The AER believes that the AEMC's interim report has appropriately narrowed the scope of the review and supports most of the AEMC's preliminary conclusions to the issues canvassed.

In particular, the AER welcomes the AEMC's findings that the current energy market frameworks are likely to deliver timely and efficient generation investment if they are appropriately maintained; and that the frameworks do not impede the efficient financing of new investment. The AER also agrees with the AEMC's conclusions that the existing electricity and gas frameworks are sufficient to cope with an increased convergence of the two markets.

With respect to retail issues, the AER notes that the Ministerial Council on Energy (MCE) has proposed that the Australian Energy Market Agreement be amended to specify that, where retail prices are regulated, the costs associated with a CPRS should be passed on to consumers. The AER also believes that this issue, and any remaining retail issues, can be dealt with through the existing policy processes outlined in the interim report.

The AER broadly agrees with the AEMC's views as expressed in the questions in issues A1, A3, A7 and A8 in the first interim report. The remainder of this submission focuses on those issues that the AER believes need further consideration in the review. The discussion highlights that relatively incremental changes to existing energy market frameworks are required to accommodate climate change policies.

This submission focuses on the issues raised in Part A of the AEMC's first interim report. The submission does not address issues raised in Part C of the interim report, regarding the Northern Territory electricity and gas markets, and responds to one issue raised in Part B, relating to the Western Australian gas market.

Issue A2: Generation capacity in the short term

Do you agree that the ability for the National Electricity Market Management Company (NEMMCO) to manage actual or anticipated transitory shortfalls of capacity is a significant issue that should be progressed further under this Review?

The AER notes that Victoria and South Australia have recently experienced actual low reserve conditions following extreme weather events. These were extraordinary events and the risk of future transitory shortfalls resulting from the early retirement of coal-fired generators is not a significant issue that needs to be progressed further in the review.

Are additional mechanisms required to complement the Reliability and Emergency Reserve Trader (RERT) and NEMMCO's directions powers, and what characteristics should such mechanisms have?

The AER considers that additional mechanisms are not required. The existing RERT mechanism appears sufficiently flexible to provide NEMMCO with the opportunity to meet any transitory shortfall in generation capacity.

Do you have any views on the detailed design and implementation of additional mechanisms?

While the AER considers that no additional measures are required, should the AEMC assess that additional measures are required, it is imperative that these not allow the system operator to procure medium or long term capacity. Such a measure would distort signals for new generation investment.

The AEMC has maintained its view that there is an 'unlikely but credible' risk of large short-term generation capacity shortfalls, given low reserve levels in Victoria and South Australia until the summer of 2010–11 and the risk of early retirement of coal-fired plant.[1] Concerns are noted in the interim report that the current framework may not 'enable NEMMCO to manage an actual or anticipated transitory shortfall in generation capacity effectively or efficiently'.[2]

[1] AEMC, *Review of energy markets in light of climate change policies: First interim report*, December 2008, pp. 17-20.
[2] AEMC, *Review of energy markets in light of climate change policies: First interim report*, December 2008, p. 18.

The AER notes that the events of late January, where actual low reserve conditions were observed for a short period in Victoria and South Australia, were the result of extraordinary weather conditions and are unrelated to the introduction of the CPRS or expanded RET. The AER considers the likelihood of a potential supply shortfall resulting from an untimely shutdown of existing capacity to be low. Factors which limit this risk include the expectation of a modest initial carbon permit price under the CPRS and the proposed $3.9 billion Electricity Sector Adjustment Scheme (ESAS) outlined in the White Paper. The ESAS helps to mitigate the risk of plant shutdown as it makes the assistance conditional on generators maintaining registered capacity at June 2007 levels. The conditionality requires that any reduction in capacity be assessed by the market operator to ensure that it is unlikely to cause a supply shortfall.

Any additional risk resulting from climate change policies will not be substantial enough to warrant any further interference with market-based outcomes. NEMMCO intervention mechanisms should be sufficient to meet any transitory shortfalls in generation capacity. On the two occasions where the reserve trader mechanism has been used, NEMMCO was able to tender for demand side resources. Additionally, the reserve trader mechanism has not been tested since changes introduced in response to the Reliability Panel's recommendations in the Comprehensive Reliability Review.

While any mechanism to complement the RERT is unnecessary, the AER is particularly opposed to the introduction of any mechanisms that would allow the system operator to procure medium or long-term capacity. Such a change would fundamentally change the current market design and impact on the efficient operation of the market. In particular, such a mechanism may distort signals for new generation investment, and lead to generation capacity and demand-side response options being withheld from the market.

Issue A4: System operation and intermittent generation

Do you agree that operation of the power system with increased intermittent generation is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

The AER broadly agrees that existing system security arrangements should be sufficiently flexible to manage the changed operating environment following the introduction of climate change policies. However the review should consider further the implications of these policies on ancillary services arrangements and whether additional ancillary services are required.

The AEMC acknowledges that the current system operation processes should allow NEMMCO to 'maintain a secure operating system that facilitates competitive energy markets in the context of large increases in intermittent generation'.[3]

However, the recent reforms of 'semi-dispatch' and enhanced wind forecasting systems—designed to manage the impacts of increased intermittent generation—are, as yet, untested. Their effectiveness will be crucial to ensuring system security.

[3] AEMC, *Review of energy markets in light of climate change policies: First interim report*, December 2008, p. 29.

The AER also notes that NEMMCO is reviewing the arrangements for network control ancillary services (NCAS). This review is, however, primarily focussed on procurement of existing ancillary services. The review does not consider whether the existing arrangements are adequate to manage network security if there is a significant increase in low inertia intermittent generation such as wind farms.

In addition, the AER recommends that the AEMC explore the question of ‘who pays’ if new or additional ancillary services are required following the introduction of climate change policies. For example the recovery of NCAS costs is currently from customers, not from intermittent generators who create the increased need for these services. This is a key issue, particularly because it is likely that new intermittent generation will be ‘clustered’ together in one or two jurisdictions. It should also be noted that the intermittent generators may get a ‘free-ride’ compared to other forms of renewable energy that are not intermittent. The AER considers, as a general principle, that the regulatory regime should apply a ‘causer pays’ principle to connecting new generation. This is discussed further in the context of market impact signals for new generation plant (Issue A6).

Issue A5: Connecting new generators to energy networks

Do you agree that the connection of new generators to energy networks is a significant issue that should be further progressed under this Review? If not, what are your reasons for reconsidering this position?

There are some impediments in the current framework for the efficient connection of new generation; however these problems can be addressed through incremental changes to the current framework.

Would any of the models identified in this chapter ensure the more efficient delivery of network connection services?

The current framework can be improved by amending the confidentiality arrangements for new connection and facilitating a joint processing approach, such as option one outlined by the AEMC in its first interim report.

Options two through four are not appropriate responses to this issue as they:

- are unnecessary and have a high risk of inefficiency and network redundancy
- would require significant changes to the current arrangements which are not proportionate to the issues the AEMC is attempting to address
- inappropriately shift all of the risks associated with underutilised network assets to customers.

Are there any other potential models that we should consider to mitigate this issue?

The AER has considered two alternatives to option one. One alternative is to require the transmission network service provider (TNSP) to publish key details regarding connection applications. Making this information available may help all potential connecting parties work with the TNSP to develop efficient connection options. An extension on this idea would be to require the TNSP, after it has published key connection application details, to invite other applicants in similar geographic areas to lodge connection agreements and then process all of the connection applications jointly.

The AEMC has identified three potential issues in the current connection framework:

- the confidentiality requirements which prevent TNSPs revealing information on the existence of other connection applicants in an area
- potential difficulties faced by TNSPs in processing numerous connection applications, and
- problems associated with building connection assets at the '*optimal size*' given the likely needs of future connection applicants.

The AEMC has identified four options which attempt to overcome these issues. Option one maintains the current arrangements, but allows for multiple connection applications to be assessed together at designated times. Options two to four require a new investment regime to allow for the development of 'hubs', extending the current network to locations where new generation is expected. These hubs will be sized to cater for the expected future power transfer requirements of the location.

The AER considers that the current bilateral negotiation process for connecting new generators can be improved to better accommodate multiple connection applications. However, the AER does not consider that the shortcomings of the current arrangements are such that significant amendments to the network planning and augmentation process are warranted.

As a general principle, the AER considers that market mechanisms are best placed to ensure efficient investment outcomes. Regulatory intervention should be limited to removing the impediments to market participants developing an efficient market response. This is particularly important in a fast changing technological environment such as the one that characterises the development of renewable generation.

The AER believes that significant improvements to the current regime are possible without altering the fundamental basis of the current connection cost funding arrangements. The four options presented in the interim report to overcome deficiencies in the current process have been considered. Given the AER's concerns regarding the risk of inefficient outcomes if the fundamental connection cost arrangements are altered, the AER supports improvements in the current framework along the lines suggested in the AEMC's option one.

Significant improvements could be made by amending TNSPs' obligations regarding disclosure of connection information, adopting the first option outlined by the AEMC or by facilitating some other joint processing approach. There may also be a role for the National Transmission Planner (NTP) to identify areas where generation can be most efficiently located. The NTP's national grid planning function will enable it to be well placed to have a view on the future efficient interface between generation and transmission development. The AER does not support options two through four identified in the first interim report as these responses are unnecessary and are likely to result in inefficient outcomes. This is discussed in detail below.

Improving transparency in connection information

The AER notes that clause 5.3.8 of the NER sets out TNSPs' obligations regarding disclosure of connection information. This clause prevents a TNSP disclosing connection application information provided under clause 5.3 to other connection applicants. Clause 5.3 applies to all registered participants intending to establish a connection or modify an existing connection (but excludes generators wishing to alter a connected generation plant).

This confidentiality obligation has been in the NER and National Electricity Code since NEM start.[4] The AER understands that the clause was originally aimed at protecting information of large industrial customers. The protection also captures generators' connection application information as it applies to applications by all registered participants (rather than just customers).

[4] While there has been some amendment to this clause in the past, the AER notes that TNSPs have had an obligation to maintain the confidentiality of connection information under the National Electricity Code since NEM start.

The AER considers that by the time a generator is ready to make a connection application it is unlikely that there is any commercial sensitivity surrounding the connection. The generator will be seeking (or have sought) town planning and environmental approvals and the intentions of the connecting generator will have been made known through the Statement of Opportunities process for the purpose of reserve assessments. These processes are likely to place a significant amount of information in the public domain regarding the project before the connection application is submitted. Given this, there appears to be little reason to prevent the disclosure of network connection plans.

The AER considers that the NER could be amended to require TNSPs to publish details of all generators' connection applications. This information could include the applicant's name, the date of the application, the specific location of the proposed project, whether the generator is scheduled or semi-scheduled, and the proposed capacity of the project. This would improve market outcomes by improving transparency for all applicants considering connecting to the transmission network. Greater transparency would also promote a greater degree of group processing among market participants.

Joint processing of connection applications

Option one provides for multiple connection applications to be assessed together at designated times.

This approach has already been implemented in the NEM.[5] VENCorp's transmission network connection augmentation guidelines allow for a group processing approach where VENCorp receives two or more applications to connect to the shared transmission network in a similar location within a similar timeframe.[6] VENCorp will assist the parties to reach a mutually beneficial commercial arrangement to fund an augmentation where each connection applicant consents to VENCorp disclosing limited information regarding the intended location, size, scope and timing of its proposed new connection to the other new connection applicants.

VENCorp's group processing approach, if applied NEM-wide, could be further strengthened by improving the transparency of connection applications. This would allow interested market participants the opportunity to bring forward other connection applications in a similar location to existing applications so that the most efficient network connection outcome can occur. Such an approach ensures efficient transmission access for new generation by allowing the market to determine which locations are most viable for new generation investment and avoids many of the risks presented by options two to four discussed below. The approach also ensures that any 'first mover disadvantage' is minimised by allowing connection costs to be shared among connecting generators.

There are also other potential options, that would rely more on market-driven joint processing of proposals. One alternative is to require the TNSP to publish key details

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[5] This approach has also been implemented internationally. Since 2005, the Irish Commission for Energy Regulation has directed network operators to adopt a group processing approach where more than one renewable generator has applied for connection in a particular area.
[6] VENCorp, *Victorian Electricity Transmission Network Connection Augmentation Guidelines*, March 2007.

regarding a connection application. This may provide other potential connecting parties with sufficient information to work with the TNSP or with the initial connection applicant on developing efficient solutions for connection in the area.

An extension on this idea is to allow the market to determine the best locations and times for 'open seasons'. This regime could involve:

- After TNSPs have published key details regarding a connection application, the TNSP could then invite other applicants to express an interest in connecting to the network in a similar geographic area (within a defined time period).

- If no expressions of interests are received within the set time period, the TNSP would continue to process the connection application (under the same arrangements as exist currently).

- If the TNSP receives an expression of interest, the interested party(ies) would be provided with a further period to lodge a connection application. All applications would then be processed jointly and the connection costs shared among all connecting parties (possibly under a similar regime to that currently applied by VENCorp and discussed above).

Prescribing a separate period for lodging expressions of interest and connection applications would ensure that the first connection applicant would only experience minimal delay (in the event that there are no other applicants interested in connecting). To prevent potential gaming of this regime, parties expressing an interest in connecting could be required to make an upfront financial commitment. This payment would not be reimbursed in the event that the party did not subsequently submit a connection application.

The AER considers that this regime would allow the market to determine the best areas and time for future developments rather than requiring TNSPs to declare 'open seasons'. TNSPs are arguably not well placed to determine the best locations for new generation sites as it is not within their field of expertise.

There may also be a role for the NTP to conduct feasibility studies on various options for identifying areas where generation can be most efficiently located. However, it should be left to the interested generation businesses to commit to the appropriate investment and bear the associated risk.

There may still be concern that even where these studies identify promising new generation sites, TNSPs might not be inclined to proceed with investment. The AEMC's report to the MCE on NTP arrangements emphasised the importance of the Last Resort Planning Power (LRPP) continuing to provide a safeguard against such planning failure. [7] Under the LRPP, the AEMC can direct a TNSP to undertake the regulatory test where an investment planning failure by TNSPs is identified. The report to the MCE recommends that the NTP have the role of advising the AEMC in respect of its LRPP function.[8]

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[7] AEMC, *National Transmission Planning Arrangements—Final Report to the MCE*, 30 June 2008, p. 79.
[8] AEMC, *National Transmission Planning Arrangements— Final Report to the MCE*, 30 June 2008, p. 78.

Determining the 'optimal size' for a connection and AEMC options two through four

The AER considers that options two to four outlined by the AEMC are not appropriate responses to this issue. These options are unnecessary, bypass any efficiency assessment under the regulatory test (or the proposed regulatory investment test for transmission (RIT-T)) and have a high potential for inefficient investment through underutilisation of the connection assets.

Options two through four are unnecessary as the current regulatory regime allows TNSPs to develop optimal extensions to accommodate future generation connections where it is efficient to do so. The regulatory test and the proposed RIT-T require a TNSP to demonstrate an investment is net beneficial. Under the test, the TNSP must compare the proposed investment against other reasonable scenarios. If it is reasonably likely that additional generators will connect in the future, then a TNSP should consider this when developing its reasonable scenarios.

A transmission project to connect future generation will pass the regulatory test and RIT-T where it maximises net economic benefits. If the investment does not do this, then it is not efficient (or '*optimally sized*') and the costs of the investment should not be recovered from customers. As noted above, the NTP may also have a role in identifying areas where generation can be most efficiently located. If the AEMC is concerned that TNSPs will not assess projects to connect new generation which have net economic benefits to customers (such as those identified by the NTP), the AEMC can use the LRPP to direct a TNSP to undertake the test.

These options have a high potential for inefficient investment through underutilisation of network assets. Given this, the AER considers that these approaches are inconsistent with the national electricity objective which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.[9]

The potential for inefficient investment is of particular concern under these options as market customers are required to bear all the risk that may arise from inefficient investment or underutilisation. The AER considers that customers should only bear this risk and fund a network augmentation if an efficiency assessment (such as the regulatory test or RIT-T) has been undertaken and the project is shown to maximise net economic benefits (or is the least cost option if the project is designed to meet a reliability obligation). The risk transfer (from TNSPs or connecting generators to customers) proposed in options two through four will distort investment decisions and may lead to inefficient outcomes.

These problems are not overcome by the '*economic test*' as described in the first interim report. This test, particularly under option two, merely reflects a financial commitment by connecting parties to meet half the costs of the proposed investment. It does not involve any efficiency assessment of the proposed investment.

Options two to four also rely on the TNSP (or some other planning body) to 'pick winners'. It would be a complex and resource intensive process to determine the appropriate size and location of the network extension investment. The network planner

[9] Section 7 *National Electricity Law*

must have perfect foresight for these options to work efficiently; otherwise customers will bear significant costs.

These options also create incentives for both TNSPs and generators to oversize the network asset to the level where the known connecting generation is just large enough to meet the described *economic test* (regardless of expected future generation). Under the current regulatory arrangements TNSPs would have a strong incentive to oversize the investment as it would receive a regulated return on any underutilised assets.[10] Similarly, where connecting generators are only required to pay for the portion of the connection assets they use, they would also have an incentive to overstate the generation potential of a region so as to benefit from the economies of scale of a larger connection asset.

Investment in surplus network capacity may also distort market outcomes. In particular, it will alter the locational signals for new generation investment and may bias the development of new generation towards particular technologies.

Finally, the AER considers that these options do not appear to be consistent with AEMC's intention to provide a clear delineation between prescribed and negotiated services in its 2006 review of economic regulation of transmission services. During that review, the AEMC expressed a strong desire to ensure that there was greater clarity between those services which should be subject to revenue regulation and those that should be subject to a more light-handed form of regulation.[11]

Any 'hubs' described under options two through four that do not meet the requirements of the regulatory test are essentially connection assets and would be considered negotiated services under the current regime.[12] The AER considers that allowing these assets to be partially funded by network customers through regulated revenues does not appear to be consistent with the AEMC's objective in the transmission revenue regulation review. Consistent with the view expressed by the AEMC in this review, the AER considers that 'hubs' which do not meet the requirements of the regulatory test should not be funded by network customers as the wider market does not obtain net economic benefits from these assets.

[10] While the AEMC noted in its determination that clause S6A2.3 of the NER allows the AER to remove assets from a TNSP's regulated asset base in limited circumstances, it is not clear how the AEMC proposes these arrangements interact with options two to four.
[11] AEMC, *Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule—Rule Determination*, 16 November 2006, pp. xvi
[12] If these assets did meet the requirements of this test they would be classified as prescribed services and would be fully funded by network customers through regulated revenues.

Issue A6: Augmenting networks and managing congestion

Do you agree that the issue of network congestion and related costs requires further examination under this Review to determine its materiality? This includes considering whether the existing frameworks provide signals that are clear enough and strong enough in the new environment where congestion may be more material? If not, what are your reasons for reconsidering this position?

The AER agrees that network congestion and related costs requires further examination.

The AER supports further consideration by the AEMC of options to manage electricity network congestion and other market impacts. In particular, the AER believes that the current market framework could be improved in the areas of:

- effective market impact signals for new generation assets
- network planning and augmentation
- optimisation of interregional transfer capability.

Market impact signals for new generation

The AER considers that as a general principle the regulatory regime should apply a 'causer pays' principle to connecting new generation. Subject to other efficiency considerations, this principle should apply to both 'deep connection' and 'shallow connection' charges as it assists in providing a strong locational signal and efficient market outcomes.

The interim report stated that the current connection framework provides clear locational signals, as new generators must pay direct connection costs and face the risk of being 'constrained off'. The AER is concerned that, while this may provide a locational signal, it may overstate the extent of the incentives for the efficient location decisions of new generation plant under the current framework. The AER noted in its previous submission that connecting generators do not pay for 'deep connection' costs for any downstream augmentations. Whilst the open access regime and the lack of firm access to dispatch provides some form of locational signal, there is no explicit signal for a prospective generator's impact on the transmission system, particularly on inter-regional impacts. This may lead to inefficient outcomes, particularly with the large amount of new generation capacity that will need to connect to the network as a result of the CPRS and expanded RET.

The AER believes that the locational signals are relatively strong where the new generation will impact on congestion within a region. In other words a new generator is less likely to locate close to existing generators if that would increase network congestion between that location and the regional reference node and result in generation in the vicinity being constrained-off. In this case customers will not see the full benefit of the new capacity as it will not be able to be fully dispatched but competition to supply more generally is not reduced. The locational signals are potentially perverse, however, when it comes to the impacts on inter-regional trade. If a new generator locates close to a region boundary and reduces imports into that region then this effectively reduces competition from generators in the neighbouring region.

By reducing imports into a region the generator may actually benefit from higher prices in its region.

The commissioning of the Kogan Creek Power Station highlights this issue. In that example, the location and unit size decisions of the generation business led to a reduction in inter-regional trade capabilities (imports into Queensland) and increased frequency control ancillary services (FCAS) costs (borne by all market generators) following connection of the unit. The impact is not just within a region. Kogan Creek is now the largest generating unit in the NEM and has resulted in a larger requirement for FCAS across the NEM.

Given these concerns, the AER considers that the review should look at mechanisms to encourage connecting generators to consider a broader range of market costs when deciding the size and location of new plant.

The AER notes that there have been a number of moves towards requiring connecting generators to avoid negative market impacts resulting from their connection. In December 2008 the MCE Standing Committee of Officials (SCO) released its *Electricity distribution network planning and connection* policy response paper.[13] SCO recommended that large users (including embedded generators) connecting to distribution networks pay for any augmentations to the shared network required because of their connection. This is expected to encourage more efficient location and investment decisions.

Additionally, recent changes to the *Tasmanian frequency operating standard* have allowed the connection of a new large generator in the Tamar Valley.[14] Normally a larger generator in a region would lead to higher requirements and costs for FCAS. The new standard, however, limits the additional FCAS costs associated with the construction of the Tamar Valley Power Station by requiring the proponent generator to avoid increasing the size of the contingency above the current level. The AEMC should consider whether this type of arrangement could be extended to congestion management to ensure that new generators consider all costs to the market when deciding the size and location of new plant.

Amending the technical access standards may be a relatively simple method of reducing the potential for inefficient market outcomes. The Electricity Supply Industry Planning Council noted in its submission to the AEMC's scoping paper that the minimum access standard in technical standard S5.2.5.12 'Impact on network capability' is too low.[15] The AER agrees with this assessment.

Under the NER, generators must satisfy a number of technical access standards before they can connect to the power system. The NER establishes an automatic access standard which, if met by the connecting generator, prevents a network service provider from denying access to the network. If the automatic assess standard is not met in the connection proposal, the connecting generator and the network service provider must

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[13] MCE Standing Committee of Officials, *Electricity distribution network planning and connection—A national framework for electricity distribution networks*, December 2008.
[14] AEMC Reliability Panel, *Tasmanian frequency operating standard review—Final report*, 18 December 2008.
[15] ESIPC, *Submission to the Review of energy market frameworks in light of climate change policies*, 14 November 2008, p.10.

agree on a negotiated access standard. This negotiated standard must be 'no less onerous' than the applicable minimum access standard as established in the NER.

Schedule 5.2.5.12 sets out the requirements on generators in respect of their impact on network capability. The automatic access standard requires a generator to have plant capabilities and control systems that are sufficient so that its connection does not reduce any inter-regional or intra-regional power transfer capability. The minimum access standard requires a generator to have plant capabilities, control systems and operational arrangements sufficient to prevent a reduction in:

- the ability to supply customer load
- power transfer capabilities into a region by more than the generator's output.

The minimum access standard prevents connections that would reduce the ability to meet the energy needs of customers within a region. However, this standard permits a TNSP to negotiate a reduction in inter regional capability (providing it is no less than the increase in capability of the new generator). A possible result of a negotiated access standard is a decrease in inter regional transfers and a reduction in the number of suppliers to the region.

The AER considers that significant improvements to market outcomes could be achieved by raising the minimum standard to prevent connecting generators from degrading inter-regional power transfer capabilities. This would mean that the business decisions of connecting generators do not impact on the efficient operation of interconnector assets. These impacts would be relatively straightforward to model and assess in response to a connection application.

The AER notes that this approach does not factor in negative impacts to intra-regional flows and as such will not expose connecting generators to the full cost of their connection on the market. The AER does not support a change in the access standard that would prevent connecting generators from degrading intra-regional power transfer capabilities. This would essentially require connecting generators to meet the current automatic access standard for all connections. Determining all intra-regional impacts would be a complex exercise that would add to the time and cost of connection applications. Additionally, such a high standard may lead to inefficient and unnecessary augmentation of the network. In any case the AER believes locational signals to reflect these impacts already exist.

Transmission network planning and operations

The interim report questions whether changes to the regulatory test are required to accommodate climate change policies. The AEMC argues that the current regulatory test appears sufficiently flexible to account for benefits that flow from the expanded RET and CPRS. The Allen Consulting Group paper similarly concludes that the 'regulatory test and accompanying guidelines would appear to provide sufficient flexibility to take account of the expanded RET scheme and CPRS when estimating benefits of a transmission upgrade.'[16] The AER agrees with this assessment of the current regulatory test.

A number of submissions to the AEMC, however, raised concerns with the ability of the regulatory test to accommodate climate change policies. The AER notes that the MCE has written to the AEMC requesting that rule changes required to implement a new RIT-T be progressed. The RIT-T will be the new project assessment and consultation process for transmission to replace the regulatory test. As part of the MCE proposal, the AER will be tasked with developing the RIT-T and associated RIT-T guidelines.

To the extent there are any shortcomings in the current regulatory test's ability to accommodate climate change policies, the appropriate forum for considering these issues is through the development of the RIT-T rule changes, the RIT-T and associated guidelines. These provide ample opportunity to clarify the treatment of the CPRS and RET under the RIT-T. For example, as suggested by the Allen Consulting Group, explicit guidance on the treatment of CPRS and expanded RET could be provided in the AER's RIT-T guideline.

Issue B1: Convergence of electricity and gas markets in Western Australia

Do you agree that the convergence of gas and electricity markets in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

While generally agreeing with the AEMC's conclusions, the AER believes that the issue of extending the gas market bulletin board and short-term trading market to Western Australia should be considered further in this review.

In the discussion of gas market arrangements in Western Australia, the AEMC pointed to the need for sufficient flexibility and responsiveness in gas market mechanisms and operational procedures and processes that respond to emergency supply shortfall.[17]

The AER notes that in southern and eastern Australia the gas market bulletin board has been established to help address these issues. The bulletin board aims to facilitate trade in gas and pipeline capacity through the provision of readily available system and market information. For example, the bulletin board provides information on outages or maintenance at production points, including updated daily demand, actual or expected changes in supply capacity to demand centres and, in the event of significant outages or system incidents, a flag indicating likely interruptions to customer supplies.

The AER believes that the review should consider whether the mandatory gas market bulletin board should be extended to Western Australia. The AER considers that there is significant merit in providing transparent, real time and independent information to gas market participants and therefore supports extending the gas market bulletin board to Western Australia. The AER also believes that other mechanisms being developed in

[16] Allen Consulting Group, *Climate change policies and the application of the regulatory investment test for transmission*, December 2008, p. 8.
[17] AEMC, *Review of energy markets in light of climate change policies: First interim report*, December 2008, p. 62.

southern and eastern states, such as the short-term trading market, should be introduced in Western Australia.

This should not prove a difficult task as provision was made to extend the bulletin board to Western Australia when the bulletin board was established in southern and eastern Australia. Further, a service similar to a short term trading market was provided in Western Australia during the 2008 gas emergency but has subsequently been discontinued.