Australian Energy Market Commission

REVIEW OF ENERGY MARKET FRAMEWORKS IN LIGHT OF CLIMATE CHANGE POLICIES

Discussion Paper

Public Forum

Melbourne

1 May 2009

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Citation

AEMC 2009, *Review of Energy Market Frameworks in light of Climate Change Policies: Public Discussion Paper, Public Forum Melbourne 1 May 2009, 28 April 2009*, Sydney

Contents

1. This paper

The purpose of this paper is to inform discussion at the public forum, which the Australian Energy Market Commission (AEMC) is hosting in Melbourne on 1 May 2009 in respect of its ongoing Review of Energy Market Frameworks in light of Climate Change Policies.

The discussion paper provides new information to stakeholders on the AEMC's ongoing development of its views on the following considerations:

- what are the most significant issues for the Review; and
- what specific changes to energy market frameworks should be recommended to the Ministerial Council on Energy (MCE) as findings of the Review.

We use the list of issues identified and discussed in the most recent AEMC consultation document for the Review, the December 2008 1st Interim Report, as a framework for providing this updated information. The information presented should be viewed as 'work-in-progress' for the purpose of informing discussion and debate at the public forum. The public forum is an important part of the process in testing this emerging thinking with stakeholders before the Review findings begin to be finalised.

2. Background

This section provides context for the issues covered in this discussion paper. It describes the role of the AEMC and the purpose of this particular Review. It also provides references to relevant further reading.

2.1. The AEMC

The AEMC is an independent statutory body, comprising three Commissioners and supported by a staff of forty people. We are based in Sydney and have a national role. Our formal statutory role spans two key functions. First, we are the Rule maker for the National Electricity Market (NEM) and for aspects of the rules for gas markets. Second, we are responsible for market development. We undertake this latter role in a variety of ways. The most significant, and germane to the issues discussed in this paper, is our role to review issues and provide advice to the main policy-making body, the MCE.

In undertaking all of our functions we are required by law to have regard to the National Electricity Objective (NEO):

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

And the National Gas Objective (NGO):

> *"to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."*

2.2. The Review of Energy Market Frameworks

The AEMC is undertaking this Review as directed by the MCE. The Terms of Reference (TOR) for the Review require the AEMC to: determine whether the existing energy market frameworks for the electricity and gas markets require amendment to accommodate the introduction of the Carbon Pollution Reduction Scheme (CPRS) and the expanded RET (eRET). Essentially the Review is to:

- examine the potential impacts of the CPRS and eRET on both the electricity and gas markets across all jurisdictions;
- determine what adjustments may be necessary within the existing energy market frameworks, having regard to the NEO and NGO – to deliver efficient, safe, secure and reliable energy supplies in the long term interests of consumers; and
- provide detailed advice to the MCE on the implementation of any amendments required.

In undertaking the Review, we are to have regard to the following:

- the MCE's requirement that amendments will only be supported if they contribute to the energy market objectives;
- the need for amendments to be proportionate;
- the value of stability and predictability in the energy markets regulatory regime; and
- any other AEMC Reviews, Rule changes or MCE reforms that may relate to this Review.

A copy of the MCE TOR can be found at www.aemc.gov.au.

The Review timetable

Document	Purpose	Date
Scoping Paper	Provides an outline of the scope of issues potentially relevant to the Review.	10 October 08
1st Interim Report	To consult on the AEMC's findings on what are the most material issues for the Review, \and why. In some cases, also to sets out preliminary thoughts on what might be required to address particular material issues.	23 December 08
Public Forums	To discuss with stakeholders the AEMC's updated views on the most material issues, following consultation. To discuss with stakeholders the AEMC's developing thinking on options for change.	1 May 09 (Mel) 8 May 09 (Per)
2nd Interim Report	To finalise the list of material issues and to consult on specific options for change.	By 30 June 09
Final Report	To present to the MCE recommendations on what changes should be made to energy market frameworks, and how they should be implemented.	30 September 09

Our Approach

For the Review, we identified a broad range of issues which we considered relevant to the Review. These were provided in our Scoping Paper, released on 10 October 2008. Those issues were considered and based on those areas where we considered the existing arrangements presented significant risks and required action in the short to medium term. We considered that it was not necessary to address the possible longer term impacts, as these are speculative and there is benefit in delaying action until the nature of those longer term impacts becomes clearer.

For the 1st Interim Report, we reviewed the range of issues, utilising the available information and evidence, outlining those which were considered material and priorities for recommending options for change. Specifically, as indicated above, we sought to focus on issues which required significant or complex changes to energy market frameworks; or created additional risks, if they are not addressed quickly. We also identified the issues, having regard to:

- whether the issue or its consequences were attributable to the CPRS or eRET;
- if there was a high probability that the issue would materialise (under a demanding but credible scenario);
- if the issue materialised, presented significant economic costs;
- if changes to energy market frameworks have the potential to make a difference; and
- those issues which would be potentially difficult to address through the existing routine Rule change governance mechanisms.

For the next phase of the Review, based on those issues which we now have concluded as material, we will recommend options for amending the existing energy market frameworks and provide our preferred approach.

Our analysis and consideration of the issues has been undertaken in consultation with a wide range of stakeholders, including through bilateral negotiations, stakeholder submissions and our Review Stakeholder Advisory Committee. These consultations have been imperative to our analysis and determining our positions to this point in the Review. Since the 1st Report and following outcomes of stakeholder submissions, we have been working with our Stakeholder Review Advisory Committee, in the form of subgroups, to progress the issues considered significant for the Review, specifically seeking advice on options for change.

2.3. Further reading

There is a range of material which we have produced that is relevant to the Review, and presents additional material to this discussion paper for stakeholders. These specific documents include:

- Scoping Paper and 1st Interim Report – Both these Reports provide an outline of the scope of issues relevant to the Review and why. The 1st Interim Report extends that analysis and provides recommendations on those issues which are considered priorities and material to amend the existing energy market frameworks.

- Survey of Evidence on the Implications of Climate Change Policies for Energy Markets December 2008 – This paper provides an overview and collates the range of available quantitative evidence on how behaviour energy markets might change as a result of the introduction of the CPRS and eRET.

- Role of the System Operator in Electricity and Gas Markets December 2008 – The paper provides an outline of the current role of the system operators for our energy markets. The tools available to those operators and processes to maintain a safe, secure and reliable energy network is also canvassed.

- Current Arrangements for Energy Retailing in Australia December 2008 – This paper describes, as at December 2008, the current regulatory arrangements for electricity retailing in the NEM and gas retailing in the eastern states gas market. The paper also outlines the current arrangements for the Retailer of Last Resort schemes (RoLR) across jurisdictions.

In addition to these papers, there are also a range of other consultant reports which have provided input to our analysis during the course of the Review. These consultants reports can be accessed on our website at www.aemc.gov.au.

2.4. Related AEMC work

The following current and past AEMC Reviews has relevance to the issues covered in the Review of Energy Market Frameworks in light of Climate Change Policies.

- AEMC Congestion Management Review (CMR);

- Update to Comprehensive AEMC Reliability Review quantitative assessment to account for CPRS and eRET (AEMC Reliability Panel) (Reliability Panel 2008 Advice);

- AEMC Reliability Panel Comprehensive Reliability Review (CRR);

- AEMC Review of Demand Side Participation in the NEM;

- AEMC Review of the National Framework for Electricity Distribution Network Planning and Expansion;

- AEMC Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets – Victoria and South Australia;

- AEMC Review of the National Transmission Planner (NTP); and

- Reliability Panel Review of Operationalisation of the Reliability Standard.

Further information on all of these Reviews can be found at the AEMC website.

3. Issues for discussion

This chapter provides an update on the AEMC's thinking in respect of each of the issues identified in the 1st Interim Report. It excludes issues relating to Western Australia and the Northern Territory. The AEMC is hosting a separate public forum in Perth on 8 May 2009. For the Northern Territory, the significant issue identified was retail which is being considered more generally as part of the wider NEM retail issues.

This updated thinking reflects our review of the fifty four written submission made to the 1st Interim Report, our ongoing dialogue with our Stakeholder Advisory Committee, bilateral discussions with stakeholders and our own analysis of the issues. We particularly welcome the ongoing contribution of the Stakeholder Advisory Committee, including through the several sub-groups that have been established.

The chapter is structured as follows. First, we consider in turn the issues highlighted in the 1st Interim Report as potentially significant. Second, we consider the issues highlighted in the 1st Interim Report as being capable of effective management through existing energy market frameworks. In both cases, we review our assessment of materiality in the light of submissions and further work. Where relevant, we describe the current position in developing recommendations for change. Third, we discuss a newly identified issue not explicitly discussed in the 1st Interim Report.

3.1. Issues identified as material risks under existing frameworks

This section updates stakeholders on the four issues identified in the 1st Interim Report as representing significant risks to the efficiency of market outcomes under existing market frameworks following the implementation of a CPRS and eRET. The issues are:

- short-term management of reliability;
- connecting remote generation;
- efficient provision and utilisation of the transmission network (including inter-regional transmission charging); and
- retail price regulation.

Sections 3.1.1 to 3.1.5 below provide summary updates of the current positions, supplemented by more detailed reasoning and relevant context. Further detailed information is provided in associated appendices in some cases. Each sub-section ends with a list of questions for discussion.

3.1.1. Short-term management of reliability

Updated position

In the 1st Interim Report we identified short-term management of reliability as an area where existing energy market frameworks might not lead to efficient outcomes following the introduction of the CPRS and eRET. We considered that the existing framework may need to be supplemented to manage better the unlikely but credible contingency of an actual or anticipated large reserve shortfall. Without amendments, a large reserve shortfall might lead to potentially more expansive and distorting intervention in the market by the system operator in the short term.

On the basis of our analysis of submissions, and further work, we remain of the view that we have appropriately characterised this issue as a material issue that requires further analysis.

We have progressed work on considering changes that should be made to energy market frameworks to address this issue. Our current thinking is that enhancements to the existing market frameworks, in addition to the current intervention mechanisms, are required. The enhancements we are considering involve the development of reserve contracting in a short term timeframe supplemented by measures that improve the visibility to NEMMCO of the level of DSP embedded in the market and measures encouraging the greater strategic use of embedded generation.

Reasoning and additional context

The CPRS is likely to increase the costs of carbon intensive fossil fuel generators. This will reduce future profitability of fossil fuel based generation and therefore the underlying value of the assets. Reduced generator asset value may mean that should a technical failure occur, investment funds will not be forthcoming to return it to service. The risk of technical failure may be higher if plant previously operated to supply base-load is required to vary its output more frequently because it has a less competitive carbon-inclusive offer price.

We are also concerned that the likelihood of shortfalls in some parts of the NEM has been increased by the uncertainty to date regarding the content and form of the CPRS and eRET.

The current energy market intervention mechanisms (directions and the RERT) were not designed to deliver large amounts of capacity, or for frequent use. We remain concerned that the potential reliability stresses that may be imposed on energy markets, described above, may lead to inefficient and undesirable market outcomes.

Submissions indicated this to be a critical issue that should be progressed. However, differing views were expressed as to whether additional intervention mechanisms were required and the form that these mechanisms should take.

In addressing this issue we are considering recommendations to amend the current energy market frameworks to address the potential risks identified. We are developing a proposal for a mechanism that would allow NEMMCO to contract, through a panel arrangement, for reserve a few weeks or days prior to the dispatch of that reserve.

The proposal we are considering provides that such a mechanism would only include payment for availability of reserve at the time NEMMCO identifies a requirement for the reserve in order to minimise any distorting effects on the market. Further payments might then be made as appropriate on the completion of necessary actions up to and including the time of physical dispatch. The AEMC Reliability Panel is in the process of developing such a mechanism as part of its work program on reviewing how the NEM reliability settings are implemented operationally.[1]

To supplement the provision of further reserve contracting powers to NEMMCO we are considering additional recommendations. Firstly we are proposing that the Rules be amended to make specific reference to the provision of DSP information by participants.

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[1] Review of Operationalisation of the Reliability Standard, Reliability Panel, March 2009.

This recommendation is to facilitate the more accurate use of current intervention mechanisms during periods of tight capacity supply, as currently the Rules are not sufficiently clear to guarantee that NEMMCO is provided with full and accurate information with respect to the level of contracted demand-side resources.

Secondly we are proposing to encourage the use of distribution connected on-site generation that currently exists in the market (in the form of emergency/standby units or units specifically designed to offset their load and manage energy flows at their point of connection to the network). Given the potential for this form of generation to offset forecast reserve shortfalls, we consider that reducing the barriers to the development of power purchase agreements for these units by ensuring the processes for connection and registration are as smooth as they can reasonably be, is beneficial. Currently the SCO is undertaking work on distribution connection arrangements and NEMMCO is reviewing its processes for registration.

Questions for discussion:

- One possible option is for a NEMMCO led reserve contracting mechanism that operates on a timeframe which is longer than nine months. Is the AEMC correct to be concerned about the risk of such a mechanism having a potentially distorting effect on the market's incentives to manage and deliver capacity?
- Is the volume of under-utilised small embedded generation capable of active participation in the market marginal or significant?
- How material is the information gap between the amount of DSP that NEMMCO is aware of and how much is actually present in the market?

3.1.2. Connecting remote generation

Updated position

In the 1st Interim Report we identified the connection of remote generation as an area where the existing energy markets frameworks might not promote efficient outcomes. This was because the existing model of bilateral negotiation for new connections is unlikely to cope as it makes it difficult for network businesses to co-ordinate generation connection proposals and to allow for efficient sizing for future connections in the same geographic area.

On the basis of our analysis of submissions, and further work, we remain of the view that we have appropriately characterised this issue as a material issue.

We have progressed work on what changes should be made to the energy market frameworks to address this issue. Our current thinking is that a new framework for major remote connections and extensions should be created in the Rules. The new framework should facilitate remote connection assets being co-ordinated and built to an efficient scale.

Reasoning and additional context

The eRET will stimulate investment in renewable generation capacity. This renewable generation is likely to be clustered in certain geographic areas, and remote to the existing transmission and distribution networks. We consider the existing framework based on bilateral negotiation will make it difficult for network businesses to co-ordinate these connections and also build them to an efficient scale so as to accommodate future connections. Therefore, the current framework risks inefficient duplication of assets and potential delays for connection, causing additional costs to customers.

Stakeholders supported this view, noting there was a need to address confidentiality and information requirements in the framework to allow co-ordination. The majority of stakeholders indicated that there was merit in seeking to address the risk of network extensions being ‘under-sized’ under the current framework, when allowance was made for likely future new generation connections. However, some stakeholders expressed caution that any new framework should avoid creating incentives to inefficiently ‘over-size’ the network in anticipation of possible, but unlikely, levels of new connection activity.

Submissions indicated that the connection of generation to the distribution network did not appear to receive adequate consideration in the 1st Interim Report. We have acknowledged this concern and, where necessary, we will consider the suitability of any connection framework developed for distribution. Our current working assumption is that the model being developed for Transmission Network Service Providers (TNSPs) is capable of being adapted for Distribution Network Service Providers (DNSPs), if it transpires that some of the potential new clusters of remote generation are more economically connected into a DNSP network rather than a TNSP network.

Of the options to address the remote connections issue identified in the 1st Interim Report, we consider that Option 2 – a network led optimal sizing option – will best address the deficiencies in the existing framework. This option involves developing a new regime for planning, charging and revenue recovery for specific remote extensions (Network Extensions for Remote Generation or NERG). The process would be triggered by expressions of interest (at different prices) from one or more ‘foundation’ generators. The range of prices would reflect the unit costs (assuming a profile of new connections over time, leading to full utilisation) of building the extension to different scales. The asset would be sized to minimise the unit cost based on expected future demand for connection, and subject to an acceptable proportion of the total cost being underwritten by ‘foundation’ generators.

The risk of anticipated volumes of generation not connecting – and the asset being underutilised - would be borne in whole or in part by customers, on the basis that customers are the beneficiaries of lower overall connection costs if the risk of underutilised extension assets does not materialise. Foundation generators would generally have better information on the likelihood of the risk, and hence might be better placed to manage it in part. We are also considering the related design question of who should capture the benefits if amounts of generation connecting are higher (or quicker) than anticipated.

A number of protections could exist for customers to limit the extent to which they are exposed to the risk of these extensions being underutilised. One design question is whether 'foundation' generators should bear some of this risk also, e.g. by being charged a higher price in the first instance with a subsequent rebate if future generation capacity does indeed connect. Other options could include the involvement of the NTP in identifying candidate extensions; consultation on proposed prices and assessment of likely future connection activity; and the application of an 'economic test' to establish whether the risk imposed on customers is acceptable or not. We think that a significant component of the 'economic test' should be based on generators' willingness to pay the cost-reflective charges – as implied by the existing framework for connection.

Further detail of this model is provided in Appendix A.

Questions for discussion:

- Is it necessary to place any additional obligations or financial incentives on network businesses to build NERGs?
- Which of the proposed alternatives best manages customers' exposure to risk?
- Will the proposed model be required for distribution and, if so, is it suitable?

3.1.3. Efficient provision and utilisation of the transmission network

Updated position

In the 1st Interim Report, we identified the issue of whether the energy market frameworks that network and generation businesses operate under would promote co-optimised decision-making in the way that they use, operate and invest in network and generation assets in light of the climate change policies. This was because it was uncertain whether the change in the economics of generator operational and investment decisions, and network responses, under CPRS and eRET, would result in a material increase in network congestion. At that time, the analysis available was inconclusive as to whether there would be a material increase in congestion.

On the basis of our analysis of submissions, and further work, we remain of the view that this issue warrants further investigation of the materiality of the problem and options for change.

The current position is that we have analysed the different routes through which de-centralised decision-making by generators and TNSPs in response to the CPRS and eRET might potentially drive inefficient costs. We have also begun the process of analysing how different sets of policy options, in combination, would be likely to influence these behaviours. We have commissioned economic modelling to complement this analytical reasoning on likely material impacts, and help inform our assessment of what policy options are proportionate. Our consideration of how to unpack and assess the different types of effects, and potential policy options, has been informed by work commissioned from Dr Darryl Biggar.[2] A copy of Dr Biggar's Draft Report has been published with this discussion paper.

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2 Dr Darryl Biggar is providing independent consultant advice to the AEMC on this Review. The AEMC is grateful to the AER/ACCC for making Dr Biggar available on this matter.

Reasoning and additional context

The CPRS and eRET will influence the economics of generation decisions compared to today. This can result in changes to dispatch and the dispersion of generation across the market, thereby affecting the pattern of flows on the transmission network. Changes to the relative costs of generators as the carbon price increases will influence generator locational entry and exit decisions, while the eRET will lead to greater investment in renewable generation plant.

If the existing frameworks result in a reduced ability to deliver efficient co-optimised decision-making under the climate change policies, then the materiality of congestion is likely to increase. This increases the economic cost of meeting electricity demand as the least cost generators may not be able to be dispatched due to network transport limitations. If generators face greater uncertainty around what volume of generation they may be dispatched for, this increases the risk of being unable to meet contracted volumes and may also introduce greater uncertainty about generation investment decisions. This can, in turn, affect timely and efficient network investment responses. Given the significant investment forecast under CPRS and eRET, this may be a material problem.

Submissions indicated a general expectation of an increased level of congestion under the climate change policies. They identified the importance of certainty around network access for existing generators, particularly when location decisions of new generators increased the level of congestion. The lack of mechanisms (including perceived difficulties with the existing Rules) to manage the costs imposed on existing generators by a new generator's location decision was a particular concern. Variations in loss factors was another factor concerning revenue certainty for generators. Views varied on whether the existing framework provided sufficient incentives for network businesses to respond to congestion. Stakeholders noted the important interactions with other elements of this and other Reviews, such as the role of DSP to manage congestion and the interactions with how remote generation is connected (discussed above).

Since transmission is both a substitute and a complement for generation, an analysis of whether outcomes are likely to be efficient overall requires us to assess the private incentives of both generators and TNSPs, and how they interact. Further, it requires us to consider both short term operational decisions and longer-term investment and decommissioning decisions:

- Generators (operational): - This concerns how generators price their output offered into the wholesale market, or whether they offer it at all. It is primarily influenced by the Rules around how the market is dispatched and priced, including whether there are payments to generators for being 'constrained' on or off;

- Generators (investment): - This concerns whether, where and what type of new generation capacity is constructed – and when existing generation capacity is decommissioned. This is influenced by long-run expectations of spot market prices and access to the network, and by the level and form of transmission charging. Because the NEM is an 'open access' regime, i.e. there are no 'firm' access rights, expectations of access to the network require consideration of likely future responses from TNSPs and from new generators.

- TNSPs: - This concerns how TNSPs make their assets available for use, and when and how they augment their networks. Because TNSPs are regulated monopolies, they are influenced by regulatory obligations and incentives. Key influences in the NEM are the economic incentives provided for under Chapter 6A of the Rules, and the set of network planning obligations including the Regulatory Test[3].

We have specific economic modelling to help inform our assessment of whether, and how, these potential effects are material. The modelling seeks to define a benchmark case of a hypothetical 'central planner'. It then compares the outcomes under the co-optimised 'central planner' case with the likely outcomes allowing for de-centralised decision-making by generators and TNSPs. To provide further insight, we are modelling differences in outcomes under 'passive' and 'active' TNSPs responses. As a further safeguard, we are asking the same question using two different modelling techniques.

The modelling will provide us with insights on potential materiality. It will not, however, provide insights on the relative impacts of different options for change. The bullet points above illustrate clearly that different types of policy change will affect behaviour in different ways. It is important, where practicable, to target policy responses on the behaviours that are causing the most material inefficiencies. It is also important to recognise the interactions within different combinations of policies.

We have engaged Dr Darryl Biggar to help inform our process of mapping policy options to issues holistically. His Draft Report is published with this Public Forum discussion paper. A key feature in the Draft Report is the emphasis on the need to consider packages of options holistically, rather than individual policy strands (e.g. how to price the spot market) in isolation.

The next stage in the work program will therefore be to apply this framework to the insights on materiality provided by the economic modelling. We will update stakeholders on the outcome of this analysis in the 2nd Interim Report.

Questions for discussion:

- How do the CPRS and eRET affect the balance between pricing signals (e.g. transmission connection costs) and non-pricing signals (e.g. access to fuel) for generation location decisions?

- What are the more important drivers for potential inefficient costs as a result of the CPRS and eRET? Operational decisions or investment decisions? Decision-making by TNSPs or by generators?

- What are the key issues to consider when assessing options for change?

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[3] The AEMC is currently considering a Rule change submitted by the MCE to replace the current Regulatory Test provisions in the Rules with provisions for a new Regulatory Investment Test for Transmission (RIT-T). For further details see the AEMC web-site.

3.1.4. Transmission charging across regional boundaries

Updated position

This issue was part of the wider issues of how transmission networks are utilised and augmented as discussed in the 1st Interim Report. We have highlighted it separately in this paper because we have progressed it to the point of a specific draft recommendation.

In the 1st Interim Report, we identified the existing inter-regional transmission use of system (IR TUOS) charging as an area of reform. This conclusion follows from our consideration of this issue, and our initial consideration of options, in our review of NTP arrangements. Recognising the importance of this issue, the MCE asked us in November 2008 to consider the issue and propose a solution as part of this Review.

On the basis of our analysis of submissions and further work, we consider this remains a material issue for further consideration.

We have developed a preferred option to address this issue. Our preferred option to reform the IR TUOS charging arrangements is a load export charge. Under this option, a TNSP exporting power into a neighbouring region would charge that importing region's TNSP a charge to reflect the network used in its own region to transport the inter-regional flows.

Reasoning and additional context

The absence of formal arrangements for charging inter-regional TUOS (IR TUOS) can dilute cost-reflective transmission pricing signals and create cross subsidies across NEM regions; customers in one region may pay for a network that is primarily used to deliver power to a neighbouring region. It can also dampen the incentives on TNSPs to pursue investments that deliver market benefits to customers outside their region. The current NEM TNSP TUOS charging arrangements do not recognise the use of a network in a neighbouring region to import or transport power from one region to the other.

As the climate change policies are likely to influence the economics of generation investment decisions, this is likely to lead to changes in network flows including changes to inter-regional flows. The current transmission pricing arrangements would not recognise greater use of one region's network to provide another region's customers with power. A mechanism for charging for the use of the NEM-wide transmission network is important to promote efficient network investment.

Submissions to the NTP Review and this Review's Scoping Paper and 1st Interim Report highlighted the importance of this issue. Submissions noted that there needed to be a mechanism to charge customers benefitting from the transmission network in other regions to better provide cost-reflective prices and to facilitate more efficient interconnector investment. In addition, stakeholders noted that TNSPs may be reluctant to invest in network to support renewable generation if their customers did not benefit from the investment. There was some support for a national approach to TUOS charging in the long term but the option of a "load export charge" could be implemented in the short term.

Of the four options considered in the NTP Final Report, we consider that the load export charge is the option that best promotes the NEO because it: provides an improved cost-reflective price signal for the use of the transmission network over the current arrangements; is consistent with the existing arrangements and can be readily implemented; is proportionate to the problem; and is supported by the majority of stakeholders.

We are proposing a simple model where each TNSP sets a charge for a point at the boundary of each adjoining TNSP's area – and levy the charge as if the flows across that point are consumed at that point. It therefore includes the locational and non-locational elements of TUOS currently levied on loads. We are proposing that the new charging arrangements be implemented with effect from July 2010.

We view the proposed change as a proportionate and robust incremental change. While it could be argued that a single NEM-wide charging methodology may deliver even stronger price signals than the load export charge and would be likely to result in greater efficiencies for the market, we are not recommending it at this time. Implementing such an option would take substantially more time than implementing the load export charge and would significantly change the existing arrangements. It is a disproportionate response to the problem.

Questions for discussion:

- Would there be any issues with commencing the new arrangements from 1 July 2011? If so, what are they?
- What are stakeholder views on TNSPs calculating the load export prices at the same time they calculate their annual prices and calculating it as if the importing TNSP was a load connected at the metering point on the interconnector at the boundary of the exporting region?
- Amounts associated with SRA are currently subtracted from the locational component of prescribed TUOS for connections points "near" an interconnector. We are seeking comments on whether to revisit this arrangement. If the amounts are not subtracted, what should be done with them?

3.1.5. Retail price regulation

Updated position

In the 1st Interim Report we identified that the regulation of retail energy prices, in its current forms, may not be sufficiently flexible to deal with potentially large and volatile changes in retailer costs driven by the CPRS and eRET. This was viewed as a material issue because of the potential cost of disruption in the market caused by regulated prices significantly lower (or higher) than underlying costs.

On the basis of our analysis of submissions, and further work, we remain of the view that we have appropriately characterised this issue as a material issue.

We have progressed work on analysing the materiality of this issue and are engaging with jurisdictional price regulators and other stakeholders. We are focusing in particular, on the risk of large, unexpected cost changes in the early years of the CPRS and the different ways in which this might potentially be handled in price regulation. We are aware that, in any event, jurisdictional regulators would have to address this issue in the processes of re-setting the current regulated prices. We hope that analysis of options through the AEMC's Review will contribute constructively to these processes.

Reasoning and additional context

The CPRS is likely to introduce additional cost uncertainty and volatility. In part, this is because it will change the cost of operating each generation plant differently. Also, as proposed, it will effectively expose carbon prices here to some international carbon prices and exchange rate volatility. Energy retailers have always been subject to wholesale energy purchase cost volatility.

However, unlike some other drivers of wholesale cost volatility, it is not clear that retailers will be able to effectively hedge against volatile carbon related costs. These factors are likely to be particularly acute in the first 12-24 months of the CPRS. It is therefore plausible that regulated prices set on reasonable expectations at the time will rapidly be revealed to be inappropriate as information on carbon prices emerges.

We are undertaking more analytical work to assist our understanding of the likely effects of carbon prices and volatility on wholesale energy costs and what instruments or strategies an efficient retailer may be able to use to manage the risks created by that volatility. Our initial view, however, is that hedging instruments available to retailers (at least initially) will be limited, given that the market does not yet exist and a number of the key policy parameters required for a forward market to emerge will not be set for some time.

Retailers indicated in submissions that they considered this to be a critical issue and should be progressed. Most expressed support for development of some form of common approach or principles for addressing carbon costs in retail price regulation.

Price regulation and regulatory frameworks vary significantly between jurisdictions and are a matter for individual jurisdictional decision. Most of the current frameworks enable an annual price review, an annual input cost review or some form of price resetting or pass through trigger in an extreme event. We will consider further with stakeholders whether these mechanisms provide sufficient flexibility if retained following commencement of the CPRS.

In addition to further exploring the materiality of this issue we will consider, together with jurisdictional regulators, some options that may be adopted to allow increased flexibility for dealing with any significant and unanticipated CPRS driven wholesale cost variation. These include options which introduce automatic 'flex' into the regulated price caps, and options which allow for dynamic adjustments to be made if forecast errors are outside certain tolerances. We will update stakeholders on this developing work program in the 2nd Interim Report.

Questions for discussion:

- For retailers with a price capped customer base, what measures or instruments will be available to effectively manage their financial exposure to carbon related cost volatility in the first twelve months of the CPRS?
- Given the uncertainty about carbon related costs in the early years of the CPRS, is regulatory review of costs each twelve months frequent enough?
- Is there a case to plan explicitly for further review and adjustment of the treatment of CPRS costs in regulated price caps shortly (e.g. six months) after the start of the scheme?

3.2. Issues identified as capable of being managed under existing frameworks

This section updates stakeholders on the three issues identified in the 1st Interim Report as representing risks that we considered could be appropriately management within existing frameworks, or where changes to frameworks did not represent an effective policy lever to address the issue. The issues are:

- convergence of gas and electricity markets;
- investment in capacity to meet reliability standards; and
- system operation with intermittent generation.

Each sub-section provides a summary update of the current position, supplemented by more detailed reasoning and relevant context. Further detailed information is provided in associated appendices in some cases. Each sub-section ends with a list of questions for discussion.

3.2.1. Convergence of gas and electricity markets

Updated position

In the 1st Interim Report we considered whether there were likely inefficiencies from the interactions between gas and electricity markets. If the CPRS results, as expected by many, in increased use of gas for power generation, then the materiality of any such inefficiencies will increase. We set out a view, however, that the existing frameworks were broadly robust in this regard. In particular, we noted that gas and electricity markets, although very different in design, both appeared to facilitate efficient trading and appeared to support efficient development of the respective network infrastructure – and therefore the allocation of available resources to the most appropriate use. We also noted that the management of short-term scarcity should be improved through the establishment of the Australian Energy Market Operator (AEMO) as the system operator in both markets.

On the basis of our analysis of submissions, and further work, we are reconsidering this assessment. In particular, we are undertaking further analysis to understand better the implications of how maximum prices are set in both markets – and in how the ability of the system operator to intervene in one market should, and is practically and legally able to, have regard to implications in the other market. These are framework questions, and not questions that can be resolved through AEMO procedures and internal communication (although, clearly, inefficiencies driven by poor communication at times of scarcity are mitigated through the establishment of AEMO).

We will report on the findings of this further analysis in the 2nd Interim Report.

Reasoning and additional context

When gas is scarce we want it to be allocated to its most valuable use. This might be electricity generation or it might be direct consumption, depending on the circumstances. Market arrangements which allow gas to be trading efficiently should allocate the scarce resource appropriately. Hence, differences in the design and operation of gas and electricity markets are not causes for concern *per se*. Rather, it is the ability to sustain efficient trading that matters. In this regard, planned developments to create a Short-Term Trading Market for gas will help address this issue in part.

The more significant consideration is whether efficient trading (i.e. allocating scarce resources to their most profitable use) will deliver efficient outcomes. If prices in gas and electricity markets were unconstrained, then the allocation would be influenced by the relative prices across the markets – which, in turn, reflects the valuation placed on different potential usages. Hence, as long as there are no other material impediments relating to access to and development of the respective networks, we might reasonable expect broadly efficient outcomes.

However, this situation is complicated by the imposition in both markets of regulated price limits. For example, $10,000 per MWh in the NEM, and $800/GJ in the Victorian gas spot market. If these regulated price limits reflect reasonable estimates of the 'true' value of lost load, then we might expect the outcomes to be appropriate. If there are differences, however, in the extent to which the regulated price limits reflect the 'true' value of lost load, then gas might be allocated to the usage which permits the highest price – and not necessarily the most efficient use.

These issues are ameliorated somewhat by the ability of the system operator to issue directions and for compensation to be paid. This provides the potential for system operator intervention to promote a more efficient outcome overall. However, to give practical effect to this desired outcome requires the system operator to fill the void that the differentially regulated maximum prices has created. What information it might use to do this, whether it is legally practicable – and whether it is a form of intervention likely to distort the market further – are all significant considerations.

Submissions, in particular from AEMO, made a number of relevant observations in this regard – and we are analysing them carefully. We will present the findings of this analysis in the 2nd Interim Report.

Questions for discussion:

- How material is the risk of regulated price caps in gas and electricity markets distorting the efficiency of outcomes?
- If material, what are the different options for addressing the risk of inefficient outcomes – and what role, if any, should the AEMO have?

3.2.2. Investment in capacity to meet reliability standards

Updated position

In the 1st Interim Report we analysed the robustness of the framework to support ongoing investment in capacity to meet the NEM long-term reliability standard of 0.002 per cent unserved energy. In particular, we sought to test the ability of the framework to deliver desired outcomes in the presence of a significantly larger proportion of intermittent generation (e.g. wind-powered generation) – which is a likely outcome of the eRET. Our finding was that the current framework was robust, with appropriate signals for new investment being provided by spot prices in different regions and the traded value of the financial contracts, such as 'caps' and 'swaps' derived from the spot market. Further, that the supporting frameworks for gas and electricity network investment and operation to handle consequent changes in the generation capacity over the medium to long term were similarly robust. For example, the expansion of peaking gas-fired generation to complement intermittent wind-powered generation.

On the basis of our analysis of submissions, and further work, we remain of the view that we have appropriately characterised this issue as being capable of being handled through the current frameworks.

We are, however, undertaking further analysis of potential alternative means of providing investment signals before we finalise our advice to the MCE on this issue. In particular, we note the concerns raised by some industrial consumers about the economic costs of volatility in pricing under the current NEM design. We will update stakeholders on this analysis in our 2nd Interim Report.

Reasoning and additional context

The energy-only market design of the wholesale spot market in the NEM, and the financial contracts that are derived from it, provide effective signals on the future need for energy and capacity. A 'swap' contract trades energy at a fixed price and location – and the price of these contracts therefore signals the value of energy. A 'cap' contract trades 'insurance' against high prices in a particular region – and therefore signals the isolated value of capacity. Expectations of spot prices will feed through to the prices at which these contracts are traded – or in decisions by integrated businesses to build their own new capacity as an alternative to buying such contracts. In turn, expectation of spot prices reflect the scarcity of capacity.

For example, if capacity is sufficient in all but peak times, then expectations of high prices at those peak times should reveal itself in high values for traded 'cap' contracts. This signals the need for peaking generation, such as Open Cycle Gas Turbines (OCGTs).

This ability to signal the specific need for peaking capacity is important in the context of the RET because of the potential need for peaking plant to complement intermittent wind-powered generation, which produces energy but cannot be relied upon to provide capacity at peak times.

A key element of the reasoning underpinning this position is our view that the NEM has robust, evidence-based processes for reviewing and updating the key market parameter (the maximum market price, also known as currently 'VoLL') to ensure that the value of scarcity can be signalled with sufficient strength to deliver enough new capacity to meet the standard. Another important consideration is the removal of policy uncertainty in respect of carbon pricing that will be realised with the introduction of the CPRS. Such policy uncertainty might be distorting the operation of these investment signals.

The Reliability Panel, for example, have noted that this might been a contributory factor to current tight capacity margins in some regions of the NEM currently. We have also had regard to the framework for investment in gas pipeline capacity in forming our view, given the potential increasing role of gas-fired generation as a less carbon-intensive technology than coal-fired generation.

Submissions from market participants were broadly supportive of the existing market design. Further, modelling undertaken by the AEMC Reliability Panel was consistent with the view that the existing framework is able to deliver desired outcomes if the settings are appropriate. The modelling also demonstrates the risk of inadequate investment if the maximum market price is too low.

Some stakeholders expressed concerns about the inherent volatility of prices in the NEM compared to alternative market designs which remunerate generators for generating output and for being available ('capacity payments'). It was contended that the CPRS would increase the volatility of pricing outcomes, and add to these existing concerns.

While capacity payments could reduce price volatility, it also involves a reduction in the role of market decision-making and an increase in the role of regulatory intervention in the market. A regulatory body is required to determine how much capacity is required in the market – a decision which is delegated to market participants in the NEM. A change to the NEM market design in this direction would also constitute a significant change with large associated transition costs. For these reasons, and having regard to the range of submissions, we are not presently persuaded that a change of this magnitude can be justified as a proportionate response to the pressures on the market created by a CPRS and expanded RET. We are, however, examining the issue further in discussion with stakeholders.

Questions for discussion:

- Do stakeholders agree that the regulatory framework for monitoring and amending VoLL, including the role of the AEMC Reliability Panel, is robust and fit-for-purpose?
- What are the potential weaknesses in the NEM's reliance on spot market prices (and financial product derived from the spot market) as the primary signals for new investment in the context of a CPRS and eRET?
- Do stakeholders agree that a move towards 'capacity payments' would be a significant change to the NEM with large associated transition costs? Why?

3.2.3. System operation with intermittent generation

Updated position

In the 1st Interim Report we analysed the ability of the existing framework to manage the task of electricity system operation with a potentially much higher proportion of intermittent generation connected to the network. This might occur because of the stimulus to investment in wind-powered generation provided by the eRET. This creates challenges for system operation because of the consequent potential for rapid variations in output, and some of the technical features of wind-powered generators compared to thermal generators.[4] Amendments have already been made to the Rules to help manage these issues, and we recognise that further change might be required. However, we found that the existing framework is likely to be able to manage the necessary change in a timely and effective way. Hence, the frameworks did not need to be changed.

On the basis of our analysis of submissions, and further work, we remain of the view that we have appropriately characterised this issue as being capable of being handled through the current frameworks.

We are, however, undertaking further analysis on the specific question of whether ancillary services markets need to be extended in anticipation of having to procure more services which are currently provided 'automatically'. This would represent a significant amendment to the Rules, and it might be appropriate for the Commission to provide recommendations to the MCE on the timing and form of any preparatory work required. We intend to provide an update stakeholders on our further analysis of this issue in our 2nd Interim Report.

Reasoning and additional context

The existing NEMMCO dispatch systems represent a solid foundation for managing the power system securely under a range of demanding scenarios. A security-constrained dispatch, which jointly minimises the costs of meeting demand and maintaining frequency and voltage, is calculated every five minutes. The technical characteristics of intermittent plant are capable of being represented within the dispatch system.

Further, a range of relevant reforms have been progressed over recent years, most significantly the "Semi-Dispatch" Rule and Australian Wind Energy Forecasting System (AWEFS). The Semi-Dispatch Rule provides NEMMCO with a degree of control over the output of wind-powered generation through the dispatch process, e.g. by being able to require units to reduce their output at times. This increases the range of tools available to NEMMCO in managing power system security, and reduces the potential for other market participants to be adversely impacted. The AWEFS provides valuable information to all market participants on the likely output, and potential variations in outputs, from wind-powered generators. This increases the ability of the market, and NEMMCO, to manage the consequences of the inherent variability in output from wind-powered generators.

The current arrangements for setting, reviewing and amending , if necessary, the Rules providing for how services to support power system operation are procured and the technical standards that are required as minimum requirements for connection, are robust enough to respond to new challenges. We believe that this is the appropriate means of

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[4] In particular, thermal generators automatically provide inertia, which is 'natural' support to power system operation – but wind turbines do not.

managing the potential need for further ancillary services, as considered likely by a number of submissions.

Questions for discussion:

- What scale of change might be required in the processes to support efficient operation of the power system with increased intermittent generation – and is the AEMC correct to characterise this as being manageable under the existing Rule change processes?
- If not, what procedural steps might be required to augment the existing processes, and who should take the lead?

3.3. Newly identified issues

This section highlights an issue that was not explicitly discussed in the 1st Interim Report, but was highlighted by a number of stakeholders as potential gaps in the AEMC's analysis.

3.3.1. Electricity distribution networks

Climate change policies might potentially have significant impacts on what electricity distribution networks are required to do. The main drivers for change are the potential growth in embedded and micro generation, and the more active management of demand. Both of these factors would tend to increase the variability of flows across electricity distribution networks. This in turn might required distribution networks to be more actively managed.

It could be argued that any changes in the required activity of distribution networks can be catered for in the existing framework of obligations and economic regulation. For example, any costs associated with building a capability to manage more dynamic flows across a distribution network could be proposed and assessed within the existing revenue determination process.

However, it could also be argued that there are potential significant gains from innovation and research in a period of rapid change for distribution businesses, which could be a challenge for the existing framework. It would appear to make benchmarking and assessments of what constitutes efficient expenditure in the future more difficult – and arguably it truncates the returns available to businesses who successfully innovate.

We will continue to analyse these issues further, although it should be noted that submissions to date have not suggested or advocated any specific options for change. We will present our analysis in the 2nd Interim Report.

Questions for discussion:

- Is the AMEC correct to characterise this as a new issue requiring consideration? If so, what specific areas should the AEMC focus its work and potential recommendations on?

4. Next steps

The next formal step in the Review process is for the AEMC to publish its 2nd Interim Report at the end of June. This will present our final analysis on the materiality of different issues, and consult on recommended options for change in a number of areas. It will also update stakeholders on any ongoing analysis to establish whether changes are required, and what form they should take.

The discussion at the public forum is an important opportunity for stakeholders to assist in informing the AEMC's thinking for the 2nd Interim Report. If, following the Public Forum you have particular points you wish to raise more formally with the AEMC, then we are inviting written submissions. However, given the limited time available before the 2nd Interim Report is to be published, we would appreciate any such submissions being brief and focused, and submitted no later than Monday 11 May 2009.

The address details for written submissions are:

E-mail : submissions@aemc.gov.au
or in hardcopy to:

Australian Energy Market Commission

AEMC Submissions

PO Box A2449

SYDNEY SOUTH NSW 1235

Submissions sent via e-mail/mail should reference the following: Company/Organisation name, Reference EMO 0001 - Review of Energy Market Frameworks in light of Climate Change Policies: Discussion Paper, Public Forum Melbourne 1 May 2009.

Appendix A

Issue: Connecting remote generation

As noted in section 3.1.2 of the discussion paper, we identified that a network led optimal sizing option is preferred. Following on from the discussion in section 3.1.2, it is considered that the preferred option/model could involve the following processes for connection:

1. Identifying the hub – The NTP and network businesses would have roles in identifying the hub. The NTP would identify regions or zones where the hub may be located, based on the likelihood of new generation being in the zone and characteristics such as the existence of sufficient scale economies. The network businesses would then undertake desktop analysis to identify relevant connection points to the shared network, possible line capacities for the hub extensions and indicative costs.

2. Identifying interest in the hub – Following the publication of possible hub locations generators would be required to express an interest in connecting in the zone before additional planning work is undertaken. At this stage, it would be non-binding.

3. Planning the hub – This step would involve the network business undertaking detailed planning of the hub, including an economic assessment in order to identify the optimal size of the hub and prospective prices if built to different scales.

4. Assessment of the hub – The network business would be required to publish a pricing statement, which would include information on its planning and assessment process and the proposed pricing for use of the hub. The Australian Energy Regulator (AER) would have the ability to disallow the proposal if it considered the proposal did not meet specified criteria.

5. Triggering the hub – The trigger for a network business commencing construction of a hub would be generators signing connection agreements. Changes in generators signing agreements from those expressing interest may mean a re-assessment of the hub asset is required at this time.

6. Revenue recovery – Charges for the hub asset would commence once generators commence using it. Revenue recovery would be based on a schedule of new generation entry such that customers are only required to underwrite capacity when assumed future generators do not connect on schedule.

Finally, generators would be provided with capacity rights to the hub asset and future generation would be allowed until the capacity of the line is met. Once capacity is met the marginal generator would have option of either:

- paying compensation to the other generators;
- agreeing to fund an augmentation to the hub; or
- agreeing to be constrained off when capacity is fully utilised.