AEMC

Australian Energy Market Commission

Congestion Management Review

Final Report

June 2008

Signed: ....

John Tamblyn
Chairman
For and on behalf of
Australian Energy Market Commission

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Citation

AEMC 2006, *Final Report*, Congestion Management Review, June 2008, Sydney

About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

Foreword

The Australian Energy Market Commission is pleased to submit its Final Report on the Congestion Management Review for consideration by the Ministerial Council for Energy (MCE).

We were asked by the MCE to undertake this Review in October 2005, with a view to identifying ways of improving the ability of market participants to manage risks resulting from congestion on the transmission networks. We have consulted widely with stakeholders through the course of this Review, and analysed a wide range of evidence and policy options.

The Final Report, together with the work we will shortly complete for the MCE on national transmission planning arrangements, brings to a close a significant programme of reform to wholesale market and transmission Rules for the National Electricity Market (NEM) over the past three years. A result is a Congestion Management Regime which promotes efficiency, and is proportionate to the materiality of congestion in the NEM historically.

The Final Report also foreshadows a new phase of review and potential reform, as market participants and policy makers seek to understand the implications of policy responses to climate change for the economics and future performance of the NEM. Any path to reduce Australia's CO_2 emissions will necessarily involve the NEM and other energy markets to a significant degree. The foundation of the NEM is a regulatory framework based on effective competition and sound regulation of monopoly businesses, which promotes safe, secure and efficient supplies of electricity to consumers. It is important that we continue to scrutinise the ability of our market Rules to integrate new policy instruments, and the changes in market behaviour that such policies will elicit, to continue to promote these positive outcomes for consumers. I would hope that the Australian Energy Market Commission can make a valuable contribution to this process.

John Tamblyn

Chairman

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Executive summary

This is the Australian Energy Market Commission's (AEMC) Final Report on its Congestion Management Review (the Review). The Final Report:

- describes the framework (the "Congestion Management Regime") for understanding and managing congestion in the National Electricity Market (NEM);.
- recommends to the Ministerial Council for Energy (MCE) specific changes to the National Electricity Rules that will improve the management of transmission congestion in the NEM. These recommendations build on a range of congestion management reforms already being implemented; and
- looks beyond the immediate MCE Terms of Reference for the Review and sets out key issues and drivers for change likely to impact on the Congestion Management Regime in the future.

The Terms of Reference for this Review required that we develop arrangements to improve the management of physical and financial trading risks associated with material transmission congestion. We were also tasked with developing a location-specific interim constraint management mechanism for managing material constraint issues until such time as they are addressed through investment or region boundary change. Furthermore, the MCE stipulated that a nodal approach to pricing is not appropriate at this stage of market development.

Context

This Report is one part of a wider and ongoing suite of reforms to the regulatory framework for the wholesale market and transmission. This wider suite of reforms impacts both the emergence and management of transmission congestion. It includes:

- regional boundary reform to the Snowy region to address the one significant, enduring and material point of congestion in the NEM;
- amendments to the Rules to introduce a new process for managing region boundary changes in the future;
- amendments to the Rules to establish a new Last Resort Planning Power (LRPP) to address the risk to the market of significant planning failure by Transmission Network Service Providers (TNSPs); and
- a new framework for the economic regulation of transmission (amendments to Chapter 6A of the Rules).

The current phase of the reform process will conclude with our review of national transmission planning arrangements, which later this year will deliver recommendations to the MCE on: an implementation plan to establish a National Transmission Planner; amendments to the Regulatory Test; and the establishment of a framework for establishing greater consistency across the NEM in transmission planning standards for reliability.

Recommended Rule changes

In response to the Terms of Reference, we are recommending to the MCE four specific Rule changes to improve the arrangements for managing financial and physical trading risks associated with material network congestion. The changes focus on enhancing the quality of information available to market participants to help them understand the risks associated with congestion, and on improving the effectiveness of risk management instruments. The changes, if implemented, will:

- formalise in the Rules NEMMCO's use of fully co-optimised network constraints for the purposes of dispatching generation and Market Network Service Providers;
- amend the Rules governing the funding of negative settlement residues so as to reduce uncertainty for holders of Inter-Regional Settlement Residue (IRSR) units;
- establish a new Congestion Information Resource (CIR), to be published by NEMMCO, which will consolidate and enhance existing sources of information relevant to the understanding and management of congestion risk; and
- clarify and strengthen the Rules governing the rights of generators who fund transmission augmentations as a means of managing congestion risk, so that in the future connecting parties make a contribution to those funded investments from which they will benefit.

Congestion and wholesale market pricing

In the NEM, the market and system operator NEMMCO dispatches the market every five minutes with the objective of minimising the cost of dispatch based on bids and offers from generators and larger load customers.[a] A generator therefore faces a risk that it might not be dispatched for its desired output. This is physical (or "dispatch") risk. A generator also faces financial (or "basis") risk to the extent that it enters into contracts referenced to prices in other regions. In other market designs generators are allocated, or can purchase, a transmission access right which affords protection against volume risk. In the NEM, a generator's "right" to use the transmission network depends on whether it is dispatched by NEMMCO or not. This is termed an "open access" transmission regime.

A regionally-priced market design has two main congestion-related policy challenges which can potentially result in decentralised decision making by market participants, which can lead to economically inefficient outcomes. First, congestion can create incentives for generators to submit bids that do not reflect costs; this is done in order to secure or avoid dispatch, i.e. to manage dispatch risk (the "dis-orderly bidding problem"). If the market is dispatched using bids that do not reflect costs, then the

[a] Dispatch is also subject to the constraint of managing the security and reliability of the power system.

dispatch may be more costly (in terms of underlying resource costs) than it needs to be.

Second, congestion, and the way it is priced in the market, can influence the locational decisions of investors (the "location decision problem"). To the extent that congestion is priced in the market, this can provide signals for the optimal timing and location of generation, network and large customer investments.

The incentives for generators to submit bids that do not reflect costs as a means of managing volume risk can be addressed by linking more closely the price a generator receives in settlement to the value of its bid. Calculating prices individually for each point (node) of the network is one means of doing this. Another method, which the MCE directed us to review, is a location-specific interim constraint management mechanism. There are many different designs for such a mechanism, but the basic framework involves (a) introducing nodal prices for generators in a designated geographical area, and (b) allocating rights to generators in the area, to be settled at the RRP. If a generator is dispatched for a volume greater than its allocated rights, then it is paid its nodal price for the surplus generation. This encourages a generator to submit bids that more accurately reflect underlying resource costs.

While in a location-specific and time-limited manner a constraint management mechanism does address the "dis-orderly bidding problem", its presence is unlikely to be the determining factor in investment decisions, and therefore it will not resolve the "location decision problem". A location-specific interim constraint management mechanism is inherently uncertain and short-term. Decisions on long-term investment—for example, whether to finance a project and, if so, what project and at what cost—will instead be dominated by the other, more enduring price and non-price signals that already exist in the market. These include price differences between regions, the prospect of changes to pricing regions, transmission losses, volume risk, connection and other negotiated transmission costs, proximity and access to the electricity grid, and proximity to transport infrastructure for generation fuel sources. Importantly, it is how these signals combine, rather than the form or strength of a particular individual signal, that matters when assessing their impact on the efficiency of outcomes for consumers.

In conclusion, we are not persuaded that a location-specific interim constraint management mechanism will promote the National Electricity Objective at this stage, given the prevailing patterns and economic materiality of congestion. Analytical work by the Australian Energy Regulator (AER) and by us suggests that productive inefficiencies from dis-orderly bidding have been relatively minor to date. In addition, empirical research from NEMMCO shows that congestion has tended to be transitory and influenced significantly by network outages, hence it would be difficult to target exactly where localised pricing interventions should be applied.

Furthermore, the introduction of a location-specific interim constraint management mechanism would add a layer of complexity to the market design and would require the resolution of significant design issues. It would introduce more settlement prices. The entitlement for a NEM generator to be settled at the regional price for its dispatched output would be removed, and replaced with another form of entitlement. The entitlement is important because it represents a mechanism for managing price risk. In some proposed designs this alternative entitlement would be allocated using an administrative rule, while in others rights would be defined explicitly and released for sale through an auction. The introduction of firm transmission rights for generation would involve fundamentally changing the NEM's design and would raise complex policy questions such as whether such rights should be grandfathered, auctioned or allocated on some other basis. Given the evidence to date does not show that transmission congestion has been a material problem, and given the complexities associated with designing a location-specific interim constraint management mechanism we are not persuaded that such a mechanism represents a net improvement in market efficiency at this time.

Future challenges

During the course of this Review there has been an increasing focus among stakeholders on the "location decision problem". This has revealed itself in proposals for more fundamental change to the Congestion Management Regime, including NEM-wide changes to abolish or amend the entitlement for dispatched volumes to be settled at the regional price and to introduce alternative mechanisms for managing price risk. This shift of focus reflects the need for new investment in the NEM, as well as the uncertainty over the nature of such investment in the context of climate change and policy responses to it.

The impact on the NEM of government policy initiatives in response to climate change (including the promotion of renewable energy technologies) will be profound. There are likely to be: significant amounts of new generation in remote parts of the network; closure of existing fossil fuel generation capacity; large shifts in the patterns of electrical flows across transmission and distribution networks; and new challenges for system operation and security of supply resulting from significant volumes of intermittent generation, such as wind turbines or small-scale embedded or micro generation. The pattern of these changes will be strongly influenced by policy settings, such as the details of a national emissions trading scheme, which are yet to be resolved.

These changes are likely to "stress test" the NEM's regulatory framework including the Congestion Management Regime. While further reforms to the Regime should be proportionate to the problem and have a robust analytical basis, we should be aware that even a proportionate response might involve significant reform to the regulatory framework. The changes to the underlying economics of the NEM resulting from climate change policy, and the consequent impacts on the behaviour of market participants and on what is required of the NEM's transmission networks, are potentially very large and may, among other consequences, result in the emergence of material transmission congestion.

If analysis were to indicate that material transmission congestion is likely to emerge as a consequence of changes to the underlying economics of the NEM, it is likely that there will be numerous options for reform that warrant consideration. For example, if new and stable points of material congestion emerge, perhaps as a result of timing differences between generator and network investment responses, it might be appropriate to re-evaluate location-specific interim constraint management mechanisms as a transitional device. A more extensive reform option would be the introduction of Generator Nodal Pricing (GNP) on a NEM-wide basis. GNP would solve the dis-orderly bidding problem, and would be more effective at addressing the locational decision problem than would a localised, time-limited pricing intervention. However, it would represent a significant change to the NEM market design and would require a complete overhaul of the market architecture for managing price risk. As a companion piece to this Review we have undertaken initial but substantial analytical work on the potential application of GNP.[b]

The profound impact of policy responses to climate change on the underlying economics of the NEM suggests that it is timely to consider the case for more fundamental change. It is important of course that any such review be comprehensive and integrated; the complexity of the interactions, and the consequent risk of unintended consequences, mean that partial approaches are unlikely to deliver optimal outcomes. The review should be based on empirical evidence and robust analysis, and informed by effective and inclusive consultation with stakeholders.

A comprehensive review would consider the need for modifications to the energy market design and regulatory framework to ensure that the impacts of climate change policies on the NEM can be accommodated efficiently and at least cost. Such a review would need to address issues including:

- the likely nature and extent of the impact of climate change policies on the structure, economics and performance of the NEM;
- the identification of any elements of the NEM regulatory framework that may require incremental or more fundamental change to accommodate the impacts of climate change policies; and
- the identification and assessment of feasible options for change to the energy market design and regulatory framework to facilitate the integration of climate change policies with the continued efficient operation and performance of the NEM.

The diagram below represents what the Congestion Management Regime will look like in the NEM—if the recommendations in this Final Report as well as recommendations from related work in the National Transmission Planner review are implemented. The diagram also identifies areas where it will be beneficial in the future to consider how climate change policies may interact with and impact on the NEM's regulatory framework.

Building upon the congestion management reforms already being implemented, this Final Report together with its recommendations for incremental improvements to the Congestion Management Regime provide important direction on the nature and scope of the priority areas for future review and reform in the context of climate change policies.

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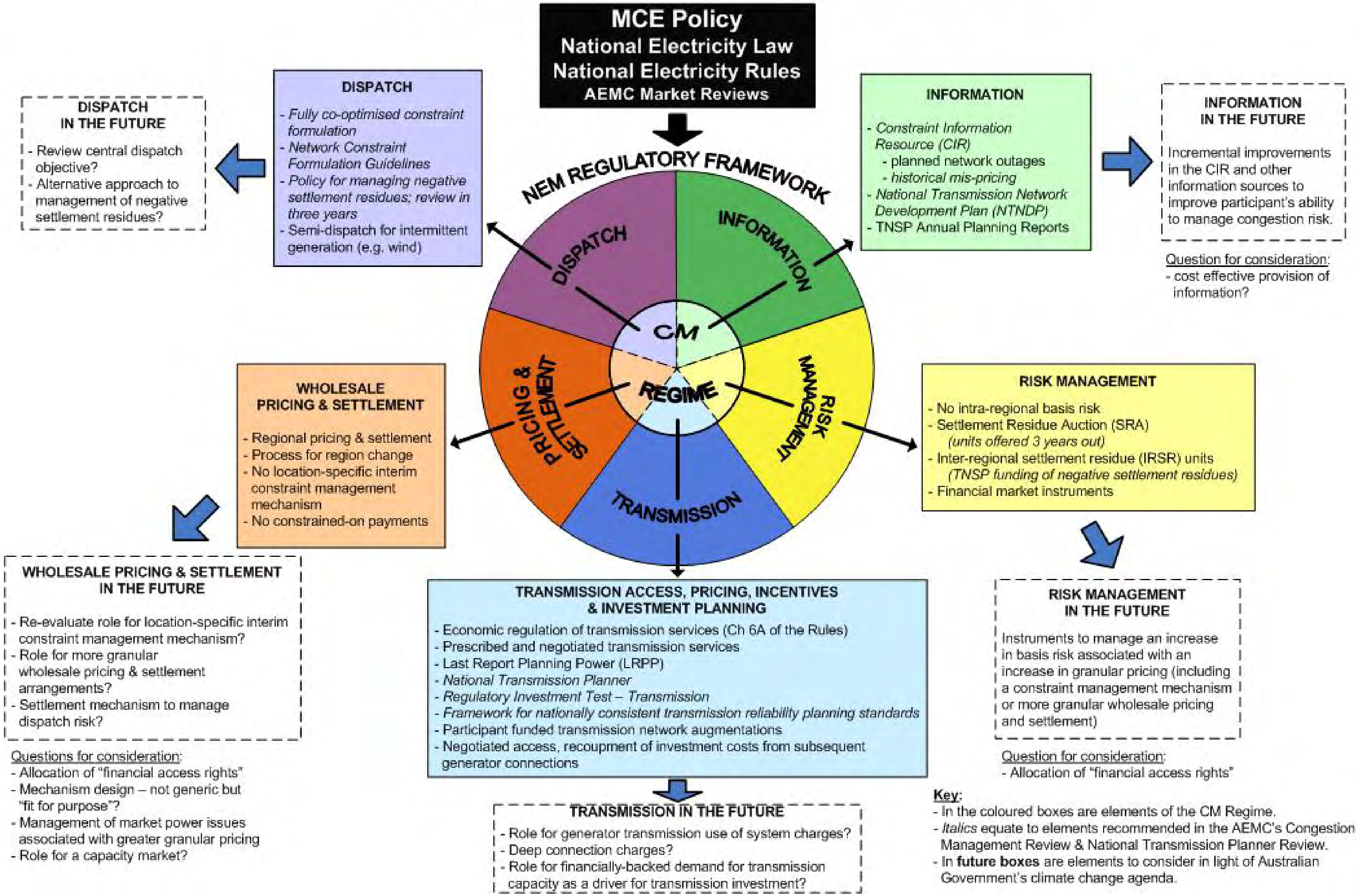
[b] We commissioned Frontier Economics to undertake a review on the potential application of GNP. We also had Professor Grant Read of EGR Consulting provide a peer review of the Frontier Economics report. These supplementary papers are available on our website: www.aemc.gov.au.

What does the Congestion Management Regime look like in Australia's National Electricity Market?



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1 Overview

1.1 Introduction

This is the Australian Energy Market Commission's (AEMC) Final Report on its Congestion Management Review (the Review). The Final Report:

- describes the framework (the "Congestion Management Regime") for understanding and managing congestion in the National Electricity Market (NEM);
- recommends to the Ministerial Council for Energy (MCE) specific changes to the National Electricity Rules that will improve the management of transmission congestion in the NEM. These recommendations build on a range of congestion management reforms already being implemented; and
- looks beyond the immediate MCE Terms of Reference for the Review and sets out key issues and drivers for change likely to impact on the Congestion Management Regime in the future.

1.2 Context and scope of the Review

1.2.1 Terms of Reference

In October 2005, we were directed by the MCE to review congestion management in the NEM.[1] We were asked to identify the financial and physical risks associated with material congestion and to propose improved arrangements for managing these risks prior to their being addressed by investment or region boundary change.[2] Specifically, the Terms of Reference directed us to examine and report on:

- improved arrangements for managing financial and physical trading risks associated with material network congestion, with the objective of maximising net economic benefit to all those who produce, consume and transport electricity (clause 3.1); and
- the feasibility of a constraint management regime as a mechanism for managing occurrences of material congestion at a particular location until they are addressed by investment or a boundary change (clause 3.2).

In undertaking these tasks, the Terms of Reference required us to:

- take account of and articulate the relationships between a constraint management regime, constraint formulation, regional boundary change criteria and review

1 Under Part 4, Division 4 of the National Electricity Law (NEL).

2 Ministerial Council on Energy (MCE), Terms of Reference clause 3.1, Congestion Management Review (CMR), 5 October 2005, p.4.

triggers, Annual National Transmission Statement (ANTS) flowpaths, the Last Resort Planning Power (LRPP), the Regulatory Test, and Transmission Network Service Provider (TNSP) incentive arrangements (clause 3.2); and

- have regard to previous work undertaken by Charles River and Associates (CRA) and the results of the limited Tumut Constraint Support Contract/Constraint Support Pricing (CSC/CSP) trial in consultation with the National Electricity Market Management Company (NEMMCO) (clause 3.3).

The Terms of Reference are provided in Appendix F.

1.2.2 Interpreting the Terms of Reference

We interpreted the MCE's Terms of Reference for this Review to mean the following:

- We should assess in parallel the economic costs of congestion and the options for improving market arrangements for congestion management, to ensure that our final recommendations are proportionate responses to the evidence and show due regard for the benefits of maintaining stability in the regulatory framework.

- Since we have a statutory duty to promote economic efficiency in the NEM, we should consider only those congestion management options that offer *net* benefits to market stakeholders.

- We should investigate the potential for location-specific interim constraint management regimes to manage location-specific material congestion until such time as it is addressed permanently by investment or region change.

- In assessing options to assist market participants, we should consider not only arrangements that could help them better manage the trading risks of congestion directly but also arrangements that could reduce the prevailing level of congestion and thereby reduce the trading risks of congestion indirectly.

1.2.3 The statutory objective

When we undertake any of our functions, including this Review, we are required under the National Electricity Law (NEL) to pursue the National Electricity Objective (NEO). The NEO is 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."[3]

[3] Section 7, National Electricity Law (NEL).

An important consideration in light of the NEO is to assess any proposed change in terms of how it may affect the market's economic efficiency. We define economic efficiency as having three elements:

- *productive efficiency*—this means the electricity system should be operated on a "least cost" basis given the existing and likely network and other infrastructure.; for example, generators should be dispatched in a manner that minimises the total system costs of meeting consumers' demands;

- *allocative efficiency*—this means electricity production and consumption decisions should be based on prices that reflect the opportunity cost of the available resources; and

- *dynamic efficiency*—this means that ongoing productive and allocative efficiency should be maximised over time; dynamic efficiency is commonly linked to the promotion of efficient longer-term investment decisions.

Our recommendations are also consistent with good regulatory practice principles. This includes seeking stability and predictability in the regulatory framework by having regard to the need, where practicable, to:

- minimise operational intervention in the market—interventions in competitive markets should be limited to addressing market failures;[4]

- promote changes that are likely to be robust over the longer term—market Rules should be stable, or changes to them predictable, so that participants and investors can plan and make informed short- and long-term decisions; and

- promote transparency in market operations—if the market requires interventions, they should be transparent and consistently applied.

In addition, we only consider options that are consistent with the continued quality, security and reliability of the national electricity system.

1.2.4 The consultation process

We have developed the recommendations in this Final Report through detailed analytical work and extensive consultation with stakeholders. Our conclusions and recommendations are based on data and analysis provided by NEMMCO, the Australian Energy Regulator (AER) and our own consultants.[5] We also sought specific comments from stakeholders at different stages of the Review on the various options and approaches under consideration.

At each stage of the Review we published papers to keep stakeholders informed of progress and to seek their comment:

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4 A market failure does not always require a regulatory intervention, however.

5 We discuss these in detail in Appendix B.

1. an Issues Paper (March 2006) that outlined our understanding of the Terms of Reference and the impacts of congestion on the market;

2. a Statement of Approach (June 2006) that set out the process we intended to take in progressing the Review and related issues;

3. a revised Statement of Approach (December 2006) that updated the process for progressing the Review and related issues;

4. a Directions Paper (March 2007) that presented some preliminary findings on materiality and a discussion of the options we considered worth closer examination;

5. a Draft Report (September 2007) that presented our proposed recommendations for improving congestion management arrangements in the NEM; and

6. Exposure Drafts (March 2008 and May 2008) that presented legal drafting to implement the changes to the Rules that we recommended in the Draft Report.

Throughout the Review process we also liaised directly with stakeholders through bilateral meetings, workshops and industry forums.

1.2.5 Related AEMC work

Since the Terms of Reference for the Review were issued, a number of reforms have been made to the regulatory framework for the wholesale market and transmission—reforms that affect both the emergence and management of transmission congestion. Reforms implemented from late 2005 to 2008 include:

- region boundary reform to the Snowy region to address the one significant, enduring and material point of congestion in the NEM;

- amendments to the Rules to introduce a new process for managing region boundary changes in the future;

- amendments to the Rules to establish a LRPP to address the risk to the market of significant planning failure by TNSPs; and

- a new framework for the economic regulation of transmission (Chapter 6A of the Rules).

Further reforms are also in progress. Our review of national transmission planning arrangements will later this year deliver recommendations to the MCE on: an implementation plant to establish a National Transmission Planner (NTP); amendments to the Regulatory Test; and the establishment of a framework for establishing greater consistency across the NEM in transmission planning standards for reliability.

This Review should be understood not in isolation but as part of a wider package of reforms. Furthermore, in developing our recommendations we have carefully taken into account how this Review and the other reforms interact, to ensure that the measures we are proposing here are consistent with, and complementary to, those reforms.

1.3 Future developments

The timing of this Review has coincided with an increasing emphasis on, and clarity around, policy responses to climate change. This is illustrated by, among other things, the commissioning of the Garnaut Review by the Commonwealth, State and Territory Governments. The stated purpose of the Garnaut Review is to examine the impacts of climate change on the Australian economy and to recommend medium- to long-term policies and policy frameworks to improve the prospects for sustainable prosperity. The Final Report of the Garnaut Review is due to be published on 30 September 2008.

Policy responses to climate change, such as an Emissions Trading Scheme (ETS) and the Mandatory Renewable Energy Target (MRET)[6], will have considerable impact on the NEM, particularly on the economics of the market, including the relative competitiveness of different generators and demand-side alternatives. In turn, this will influence the dispatch process, the demand for new connections, and the patterns of electrical flows across transmission and distribution networks.

Climate change policies are emerging, coincidentally, at a time when the NEM is experiencing a tightening supply-demand balance. This compounds pressure for new investment in the market. It may also have implications for the reliability of supply as well as the security of the power system.

These developments will “stress-test” the existing Rules and regulatory framework for the NEM, including the management of congestion. We comment on some of these issues in the chapter 4 of this Final Report.

1.4 Structure of this Final Report

There are three other chapters in the Main Body of this Final Report:

- *Chapter 2* explains what congestion is, who it affects, and why it needs to be managed. It describes the purpose and characteristics of a Congestion Management Regime (CM Regime). It also presents the evidence on the prevalence and economic materiality of congestion in the NEM over the past five years.

- *Chapter 3* sets out the component parts of the CM Regime for the NEM and describes how we recommend improving it to support more efficient outcomes.

- *Chapter 4* examines how the CM Regime may need to evolve in the future in order to accommodate policy responses to climate change and a tightening supply and demand balance.

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[6] The MRET target is 45 000 GWh of output from renewable generators by 2020.

Appendices provide background information and/or more detail on congestion and its context:

- *Appendix A – Introduction to congestion*
- *Appendix B – Prevalence and materiality of congestion*
- *Appendix C – Assessment of Congestion Management Regime elements*
- *Appendix D – Outlook for future trends in congestion*
- *Appendix E – Additional material*, which includes:
  - types of constraints
  - review of CRA work on constraint management
  - Network Support and Control Services
  - Positive Flow Clamping.
- *Appendix F – MCE Terms of Reference for this Review*
- *Appendix G – Draft Rules*[7]
- *Appendix H – Glossary*

[7] In the Review's Terms of Reference, the MCE requested that in addition to making recommendations we should develop draft Rule changes to implement the recommendations. These draft Rule changes are presented in Appendix G. They articulate provisions to implement our recommendations for network constraint formulation, the establishment of a Congestion Information Resource, the recovery of negative settlement residues, and contributions to transmission augmentation.

2 Congestion in the NEM: Concepts and evidence

2.1 What is congestion?

Electricity is transported from suppliers (generators) to consumers (retailers and large customers) along a transmission network. "Congestion" is what happens when there is a bottleneck somewhere on this network. That is, whenever a particular element on the network (e.g. a line or transformer) reaches its limit and cannot carry any more electricity than it is carrying already, it is "congested". The flow of power across the network means that when a limit is reached on one part of the network, adjustments have to be made in generation and consumption across the network to ensure that the limit is not exceeded.[8]

In technical terms, congestion places network constraints on dispatch. It interferes with the market's dispatch objective of meeting demand at the lowest possible cost. (In the absence of congestion, electricity to meet demand is supplied by the lowest-cost generators;[9] when congestion arises this may not be feasible, so higher-cost generators may have to be dispatched instead.) This introduces risks for the market, which consequently affects bidding[10], dispatch, pricing, contracts, and risk management, as well as long-term investment decisions.

2.2 Who is affected by congestion and how?

Congestion affects everyone in the market. It affects generators by increasing their exposure to financial and physical risks. It affects retailers by increasing their exposure to financial risk. It affects investors by creating a greater level of uncertainty about locational decisions (i.e. where to invest in transmission and/or generation). It affects NEMMCO (the system and market operator) by increasing the possibility of system security and supply reliability problems. In addition, by increasing the price of electricity, it also affects both wholesale and retail customers.

In response to the risks caused by congestion, market participants engage in strategies and activities to manage those risks. This leads to behaviours—such as "dis-orderly bidding" by generators—that reduce the economic efficiency of the NEM in both the short and long terms.

2.2.1 How congestion influences the behaviour of participants

Congestion can introduce two kinds of short-term risk that generators have to manage:

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8 See Appendix A for an "Introduction to congestion in the NEM".

9 This assumes that generator bids reflect costs.

10 In the NEM, the term generator "bid" has the same meaning as generator "offer", and "rebidding" has the same meaning as "re-offering".

- dispatch risk (also known as physical or volume risk); and
- basis risk (also known as financial or price risk).

The magnitude of these risks depends on the pricing and settlement arrangements in the market and how explicitly those arrangements reflect congestion.[11]

Dispatch risk

A generator faces dispatch risk when the Regional Reference Price (RRP)—i.e. the *actual* (or settlement) price it is paid for supply—diverges from its local (or nodal) price—i.e. the *hypothetical* price reflecting its local demand and supply conditions. The RRP is set at the cost of supplying an additional megawatt of electricity at the regional reference node (RRN). The RRN is a specified point in a region; it is normally close to the region's largest demand centre.

Dispatch in the NEM is based on a comparison between a generator's offer price and its local price. Dispatch assumes that generator offer prices are cost reflective.

When there is no congestion, local prices across the network are the same as the RRP. Congestion changes that. When congestion arises between a generator's location and the RRN, the generator's local price and the RRP can diverge. This "mis-pricing" creates dispatch risk for the generator, exposing it to the possibility of:

- being dispatched and settled at a price that does not meet its incremental costs (i.e. it is negatively mis-priced or "constrained-on"); or
- missing out on being dispatched even though its offer price is below the RRP (i.e. it is positively mis-priced or "constrained-off").

In order to manage dispatch risk, generators change their bidding behaviour such that they no longer bid in a cost-reflective way. That is, dispatch risk creates an incentive for generators to engage in "dis-orderly bidding". At the extremes, generators may bid in at the market floor price (-$1 000/MWh) to avoid being constrained-off, or at the market ceiling price ($10 000/MWh) to avoid being constrained-on.

Generators' bidding practices in turn affect dispatch. Mis-pricing leads to dis-orderly bidding, which can result in the dispatch of higher-cost generators over lower-cost generators. To the extent that generators' congestion-influenced bids distort what would otherwise be efficient dispatch outcomes, mis-pricing introduces productive inefficiency.

Basis risk

Basis risk arises when the settlement price a participant pays (or receives) diverges from the *contract* price the participant agreed to.

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11 Why this is a consequence of a regionally-priced market is explained in Appendix C.

Currently, participants do not face basis risk when trading within a region. This is because generators receive (and loads pay) the same price for producing and consuming electricity within a region. This is the case irrespective of the level of congestion within that region. This means both generators and customers have a "perfect" hedge built into the settlement arrangements for any contracts between two participants in the same region.

Participants do face basis risk when trading between regions, however. When congestion arises between regions, the price between those regions diverges. A participant who contracts between these regions needs to manage the price difference to the extent that it has contracted at one region's RRP but is settled at the other region's RRP.

Participants use financial instruments to help manage this inter-regional basis risk. Their willingness to contract between regions depends on: (a) the ability to obtain risk management instruments; and (b) the usefulness of those instruments in managing the risk. To the extent that participants can access instruments, and that these instruments provide an acceptable hedge cover, participants may choose to trade inter-regionally. If participants cannot obtain sufficient hedge cover, they may choose not to contract across regions. This can reduce the potential contracting pool at load centres, which limits the extent of competition in the contract market.

2.2.2 How congestion influences the behaviour of investors

In the long run, mis-pricing may distort investment decisions for both supply and load. This includes decisions on technology, location and timing. For example, a new entrant may apply a higher discount rate if the level of dis-orderly bidding in an area makes it difficult for that new entrant to manage its own dispatch risk. If the new entrant is more efficient than the existing generators, this could compromise dynamic efficiency.

In the longer term, this can weaken economic signals that support efficient locational investment decisions by generators and large industrial and commercial users (the "location decision problem").

2.2.3 How congestion affects market outcomes

As well as influencing the behaviour of market participants, congestion affects the market as a whole. First, it can increase the overall cost of electricity supply because it interferes with the objective of meeting demand at the lowest possible cost. Second, the physical and financial impacts of congestion, combined with participants' efforts to manage them, can potentially compromise 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".

In summary, congestion impacts market participants, affects their behaviour (in response), and has implications for short- and long-term market outcomes.

2.3 Managing congestion

To eliminate *all* transmission congestion would be neither cost-effective nor efficient. It would lead to over-investment in transmission capacity. In the NEM's radial network with dispersed sources of generation and centres of demand, the costs of building out all transmission congestion would be prohibitively high. There is, therefore, an *efficient level* of congestion, and it is this that needs to be managed.

The management of congestion can be considered narrowly, by focusing on specific mechanisms for dealing with congestion at particular locations, or more generally, by considering the framework that determines or influences behaviour in the presence of congestion. The Terms of Reference require us to look at congestion from both perspectives: the arrangements in general as they impact on the management of physical and financial risks arising from congestion, and the narrower question of the design of specific mechanisms for managing congestion at particular locations.

2.3.1 What is a Congestion Management Regime?

The incidence and materiality of congestion at any point in time depends on the behaviour of generators, large demand customers, investors, network businesses, and the market and system operator:

- Generators and large demand customers make bids and offers in the wholesale market, revealing the price at which they are willing to produce or consumer different volumes of electricity. In the longer term, generators, large demand customers and other investors also make investment decisions, for example to build a new power station or to close an existing one.

- Network businesses make decisions in the short term on which network elements are in service, and in the long term on what network elements to build or decommission. Collectively, these decisions define the physical network that is available to the system operator to dispatch flows across.

- The market and system operator NEMMCO makes decisions, based on market participant bids and offers and on the available physical network, as to which generators should run in any given five-minute dispatch interval to meet demand. It must make these decisions in a way that will maintain power system security and reliably meet supply.

The decisions made by generators and large demand customers in the shorter term, and by generators, large demand customers and investors in the longer term, will be conditioned by the need to establish contract positions and to manage risk in respect of those contract positions. A CM Regime is the set of rules that influence these decisions.

Given that it is not possible to manage congestion using a single rule or instrument, a range of measures are necessary. The challenge is to identify which combination of measures will promote efficient outcomes given the prevailing patterns of congestion and investment environment.

The MCE recognised the importance of identifying the inter-linkages between the various measures for managing congestion.[12] The Terms of Reference for this Review required us to examine the role of a location-specific interim constraint management mechanism that could be applied selectively, and on a time-limited basis, to a particular constraint. Such a mechanism is one potential element of a CM Regime.

Another key element of a CM Regime is the information available to participants. The Rules currently influence how participants respond to the physical and financial market risks arising from congestion. However, participants could make more informed decisions if they understood the nature of the risks better. The more information they have, the better their ability to manage those risks. Consequently, although under the current Rules some information on congestion has to be provided to the market, there will be a greater role for congestion-related information in a CM Regime.

In generic terms, a CM Regime will comprise Rules and information for the following elements of an electricity market:

- *Dispatch*—how the system and market operator decides which generators will run to meet demand. This will primarily influence market participants' perceptions of dispatch risk.

- *Wholesale market pricing and settlement arrangements*—how generators at different locations are remunerated in the spot market for their output. This, in combination with an understanding of the Rules for dispatch, will influence generators' bidding strategies. A location-specific interim constraint management mechanism is an intervention in the wholesale pricing and settlement arrangements that focuses on managing a particular constraint at a particular point in time.

- *Transmission access, pricing, incentives and investment planning*—how connection to and use of the transmission network is provided and charged to market participants, and how network augmentations are planned. These are another form of economic signal to market participants relating to the direct cost of connection and to the indirect impacts of network investment on pricing and dispatch outcomes in the longer term.

- *Risk management instruments* – what tools are made available through the Rules to enable market participants to manage basis risk.

2.3.2 Why manage congestion?

There are many reasons why it is important to manage congestion. It is necessary for maintaining the physical and operational security of the power system. It also has important implications for spot prices, the degree of competition, bidding incentives for market participants, and the levels of basis and dispatch risk borne by

[12] CMR Terms of Reference, clause 3.2, p.4.

participants. In the long term, the manner in which a market manages congestion affects the investment decisions of new generators, load, network service providers, and the opportunities for alternative energy sources.

The approach taken to congestion management therefore plays an important role in:

- ensuring power system security and supply reliability;
- minimising the immediate cost of meeting demand; and
- ensuring that market participants receive the appropriate information about the cost and location of congestion, and therefore make appropriate investment decisions in the longer term.

An effective regime for managing congestion can assist electricity producers, large customers and transporters in managing risks and making informed decisions, and thereby promote efficient outcomes for all consumers.

2.4 Congestion to date

2.4.1 Evidence-based approach

Our recommendations have been informed by evidence on the prevalence and materiality of congestion in the NEM. Much of this evidence is based on experience in the recent past. While such historical evidence can provide valuable insights, it has its limitations. We need to be aware that in the future patterns of congestion might materially change, and we need to identify and understand the drivers for any such change. (These points are discussed further in Chapter 4.)

The available evidence also needs to be interpreted carefully. Over the short and long term we looked at the incidence, duration and location of congestion as well as at indicators of its economic costs. It is important to consider both incidence and economic cost. A high incidence of congestion does not necessarily mean a material market impact. On the other hand, a low incidence of congestion may have a significant impact on market dispatch. To get a complete picture of congestion in the NEM, therefore, we examined a range of indicators.

2.4.2 The evidence base

We considered the available historical data on the level and duration of congestion from several sources: the annual AER reports on the indicators of the market impact of transmission congestion; NEMMCO's Statement of Opportunities - Annual National Transmission Statements (SOO-ANTS); and work conducted by Dr. Biggar[13] and NEMMCO on the patterns of mis-pricing in the NEM. We also considered mis-pricing cost analysis prepared by Frontier Economics and a

[13] Dr Darryl Biggar is an economic consultant to the ACCC and AER and an advisor to us on the Congestion Management Review.

stakeholder report prepared by Intelligent Energy Systems (IES) that looked at the potential future long-term investment impacts of different pricing arrangements.[14]

2.4.3 Key findings from the analysis of the evidence

The data from the last four to five years showed that congestion in the NEM was unpredictable, with both the location and duration of significant binding constraints varying significantly. Also, most constraints had a relatively short "life–cycle", in that they caused some mis-pricing for only one or two years before being largely addressed by investment in transmission or generation infrastructure. There were only a few locations where congestion was persistent. Overall, with the exception of the Snowy region, congestion did not appear to be a major problem in the NEM.

Here are some of the key findings:

- Dr. Biggar concluded that the NEM-wide incidence of mis-pricing had increased since 2003/04. He found that mis-pricing was a frequent and enduring issue at a relatively large number of connection points, stating that some 95 connection points were mis-priced for an average of more than 100 hours per annum over the three years of his study (2003/04 to 2005/06).

- NEMMCO's preliminary study confirmed Dr. Biggar's finding that there had been an increasing trend in mis-pricing from 2003/04 onwards. However, it also showed that over the study period (2001/02 to 2005/06) the number of connection points being mis-priced was fairly steady. NEMMCO noted that the reasons for these trends were specific to the region and the situation at the time. NEMMCO also commented that the progressive conversion of "option 8" constraints to a fully co-optimised formulation would have contributed to the increase in frequency and duration of mis-pricing.

- Generators were significantly more likely to be positively mis-priced (constrained-off) than negatively mis-priced (constrained-on). In 2005/06 the ratio between the two forms of mis-pricing was 3 to 1.

- The average mis-priced amount per mis-priced dispatch interval was very high, ranging from around $500 to $1 000/MWh for generators that were positively mis-priced and from around -$300 to -$6 000/MWh for generators that were negatively mis-priced. These results suggest there is a high probability that dis-orderly bidding occurred when a constraint bound.

- Dr Biggar found that only a small number of connection points were mis-priced by more than $5/MWh for all three years of his study. These connection points all related to small gas or hydro plants in Queensland.

- Dr Biggar also found that the average hours of mis-pricing due to system normal events were fairly constant over the three years, at around 50 hours per year. However, there was an increasing trend in the duration of mis-pricing due to

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[14] See Appendix B for more information about these sources and their findings.

transmission outages, from 20 hours in 2003/04 to over 120 hours in 2005/06. This was mainly due to the increased incidence of outage-caused congestion in both the Snowy and Queensland regions. The Queensland increase was due to a number of lightning events affecting flows between Central and South Queensland and an outage at the Gladstone transformer.

2.4.4 Material congestion in the NEM has not been substantial to date

In addition to considering the prevalence of congestion, we also looked at the economic costs of congestion over both the short and long term as well as the implications for risk management and contracting.

2.4.4.1 Short-term outlook

AER indicators

In terms of the short-term outlook, we examined the AER's indicators of the annual dispatch costs of congestion over the period 2003/04 to 2006/07. These indicators include the total cost of constraints (TCC), the outage cost of constraints (OCC), and the marginal cost of constraints (MCC) (see Table 2.1 below). All of these indicators involve a comparison between actual dispatch costs (based on participants' bids and offers) and hypothetical dispatch costs in circumstances otherwise identical (i.e. same bids and offers) except that no congestion occurred.

Table 2.1 AER indicators of the market impact of transmission congestion

	Total Cost of Constraints (TCC)	Outage Cost of Constraints (OCC)	OCC as % TCC	TCC Index (2003/04=100)	OCC Index (2003/04=100)
2003/04	$36m	$9m	25%	100	100
2004/05	$45m	$16m	35%	125	178
2005/06	$66m	$27m	41%	183	300
2006/07	$107m	$58m	54%	297	644

Note: The 2005/06 figures include congestion within the Tasmanian transmission network for the first time.

Data source: AER, *Indicators of the market impact of transmission congestion*, reports for 2003/04 (9 June 2006), 2004/05 (10 October 2006), 2005/06 (February 2007), 2006/07 (November 2007).

Converting the AER's measures into indices with a base year of 2003/04 revealed a near three-fold increase in the TCC and just over a six-fold increase in the OCC in the four years to 2006/07.

The assumptions and methodology behind these measures mean there are limitations to what conclusions can be drawn. That being said, the magnitude of the AER estimates was very small compared to the NEM's annual wholesale sales of $6 billion. Also, an increasingly significant proportion of the TCCs was related to transmission outages (over 50% in 2006/07), and the majority of the costs occurred on only a few days each year.

Frontier Economics' mis-pricing costs analysis

Frontier's analysis attempted to calculate the costs of dispatch inefficiency caused by generators bidding in a dis-orderly manner to avoid being either constrained-on or –off in a market experiencing mis-pricing. This analysis did not allow for any material market power, meaning that: (a) generators that were not mis-priced were assumed to bid their capacity into the market at their short-run marginal cost; (b) generators that were constrained-on were assumed to bid their capacity at $10 000/MWh to avoid being dispatched; and (c) generators that were constrained-off were assumed to bid their capacity at -$1 000/MWh in order to be dispatched. The modelling period was the 2007/08 financial year.

Frontier found that production costs in the scenario with mis-pricing across the entire NEM were $8.01 million higher than in the base case in which all generators were assumed to bid their capacity at short-run marginal cost. This represented 0.47% of the NEM's annual total production costs of more than $1.7 billion, which indicated that the impact of constraints binding and causing inefficiency through mis-pricing was relatively low.

Economic modelling of congestion in the Snowy region

The modelling we undertook on the various proposals for managing congestion in the Snowy region found that the dispatch efficiency impacts of eliminating mis-pricing, even in an environment of strategic bidding, were likely to be relatively small compared to the overall level of trade and welfare surpluses in the NEM.[15]

2.4.4.2 Risk management and contracting

As discussed earlier, congestion can contribute to participants' trading risks. The materiality of the financial risks arising from congestion depends on the availability and usefulness of risk management instruments. The "firmness" of an instrument represents the percentage of risk covered by that instrument. For example, an instrument that is 50% firm would only cover half of a participant's basis risk.

Our analysis found that the level of firmness of the inter-regional settlement residue (IRSR) unit instrument varied greatly across the NEM interconnectors, ranging from only 0.9% firmness for the Snowy-to-NSW interconnector to 90.7% for the NSW-to-Snowy interconnector. Most other interconnectors ranged between 60% and 80% firmness. The study found that the lack of firmness was caused by lower transfer capabilities, meaning that one IRSR unit represented less than 1 MW of interconnector flow at the time of the price differences. Negative settlement residues accounted for a very small percentage of the lack of firmness, in part due to

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15 See AEMC 2007, *Abolition of Snowy Region*, Rule Determination, 30 August 2007, Sydney.

NEMMCO's practice of "clamping" flows in some circumstances where negative settlement residues would otherwise accumulate.

Participants acknowledged the lack of firmness offered by IRSR units, but expressed concern about the risks of introducing major changes, especially if they were made in isolation from initiatives to improve transmission performance. We also found that participants' appetite for inter-regional trading varied greatly and that they used a portfolio of instruments to manage risk rather than just relied on a single mechanism, like IRSR units.

2.4.4.3 Long-term outlook

We need to understand the long-term implications of congestion as well as the short-term, especially in light of the significant amount of energy investment planned for the next five to fifteen years. We therefore considered several approaches and data sources in order to assess the long-term outlook. (We have also considered the potential impact on the materiality of congestion of future developments in the market, as well as the pressures these developments might exert on the current Rules and regulatory framework. These matters are discussed in Chapter 4.)

In its 2006 SOO-ANTS, NEMMCO estimated that the present value of the total market benefits of costlessly removing all network constraints would be $2.2 billion over the next ten years, with benefits arising from lower dispatch costs, deferral of capital expenditure, and reliability savings. It would be inefficient to build out all network congestion, however, and therefore such significant market benefits are unlikely ever to eventuate. So, while informative, this analysis has limited applicability to our Review.

We also considered a report by IES that estimated what the longer-term impact would be if all congestion in Queensland were priced. The report found that pricing arrangements for both congestion and transmission would lead to a more efficient pattern of generation and transmission investment. Furthermore, a scenario that combined both pricing arrangements yielded greater efficiencies compared to a scenario that relied solely on more granular congestion pricing.

The IES report represents an important and useful attempt to quantify the long-term market benefits of various pricing regimes. However, like the NEMMCO analysis, its applicability to our Review is limited. This is because the IES report contained simplifying assumptions which, while necessary and understandable given the limited time IES had to undertake such a substantial modelling exercise, were not reflective of the actual market environment. Specifically, the modelling did not factor in the risk implications and implementation costs of introducing greater locational pricing, nor did it include a review of whether the location of additional generation was plausible. This means that the cost estimates of the current regional pricing regime were probably overestimated because they did not account for factors that are potentially quite influential, such as the risk implications of a nodally-priced regime.

The IES report provides a useful starting point for assessing the costs of congestion and the possible benefits from pricing it. However, it is unlikely that the benefits would be as great as the report suggests. The case of the IES report also demonstrates just how difficult it is to quantify dynamic efficiency benefits.

2.4.5 Persistent and significant congestion in the Snowy region has been fixed

Market participants agreed that there has been significant material and enduring congestion in the Snowy region.[16] Although a number of temporary ad hoc measures have been implemented over recent years to address the dis-orderly bidding incentives triggered by this congestion, it remained unlikely that long-term investment would fix the problem in the foreseeable future. This was due to the high market cost that would result from taking the lines out of service in order to upgrade them and the environmental issues associated with development in the national parks across which the Snowy region lies.

For these reasons the Snowy region will be abolished on 1 July 2008. This will introduce a region boundary across the point of material and enduring congestion.[17] Abolishing the Snowy region will create the strongest incentives for generators to bid in a more competitive way. It will improve dispatch efficiency and will result in more cost-reflective spot prices. We expect that the shorter-term competitive benefits will impact positively on contract markets and provide clearer signals for efficient investment and consumption in the longer term, ultimately benefiting end-use customers. The abolition of the Snowy region is a proportionate and stable response to a major legacy congestion issue.[18]

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16 AEMC, Congestion Management Review, Industry Leaders Strategy Forum, October 2006, Sydney.

17 See AEMC 2007, *Abolition of Snowy Region*, Rule Determination, 30 August 2007, Sydney.

18 This is the first substantial region change in the NEM.

3 Improving the Congestion Management Regime

Having given an account in the previous chapter of the prevalence and materiality of congestion, we now turn to the CM Regime and how it can be improved. The discussion focuses on our recommendations for improving the provision of information and for strengthening existing risk management instruments—incremental changes consistent with the NEM market design. We also explain why we are not recommending more extensive changes to how the wholesale market is priced, for example by introducing a location-specific interim constraint management mechanism.

When considering how a CM Regime helps promote efficient outcomes it is important to consider how its component parts combine to send to market participants economic signals that influence investment or behaviour at particular locations. For this reason we will begin by explaining the range of economic signals that already exist in the CM Regime. We will then turn to our recommendations for incremental but important change.

3.1 The nature of locational signals in the CM Regime

In the NEM today, the CM Regime provides a range of locational signals to market participants:

- *Price separation between regions*—congestion can lead to regional differences in the cost of supplying demand. In the NEM market design physical network constraints reveal themselves in the market through differences in the RRPs. Systematic differences in RRPs provide important signals as to where additional generation capacity might be most valued.

- *The prospect of changes to pricing regions*—the signals provided to investors through wholesale market pricing are also conditioned by the possibility of region boundaries being changed. In 2007 we amended the Rules to put in place a new process for changing region boundaries.[19] A case for region change must now be based on economic evidence of an enduring and material congestion problem. This means that investors need to factor in the possibility that congestion points which are not currently priced in the NEM region model, including new congestion points created by new investment, may be priced in the future as a result of a region boundary charge.

- *Transmission losses*—generators that are closer to centres of demand will, other things being equal, be cheaper (and therefore more competitive) than generators further away from demand. This is because of losses on the transmission system. Transmission losses are reflected in the market through the application of loss factors. There is a static loss factor for each point within a region (reflecting an annual average level of losses at that point), and there are dynamic loss factors which are calculated every five minutes for flows between regions.

[19] This new process commences on 1 July 2008.

- *Dispatch risk*—generators at different locations face different probabilities of not being dispatched due to constraints on the network. Other things being equal, a generator located at an uncongested point on the network will be more competitive than a generator located at a congested point on the network. This might reveal itself in an ability to offer greater volumes in the contract market at a more competitive price. It might also reveal itself in the form of a higher discount rate being applied by investors in considering investment options with higher dispatch risk.

- *Connection charges*—generators pay a "shallow" charge for the connection service provided by a TNSP. This charge reflects the cost of the assets required to connect the generator to the main interconnected network. Additionally, the Rules provide for generators to negotiate different levels of connection service. This may involve a generator agreeing to fund deeper reinforcement work on the transmission network in return for reduced dispatch risk. It may also involve a generator recouping some of the costs of deeper reinforcement work if new generators subsequently connect. These costs are forms of locational signal.

- *Regulated transmission investment*—TNSPs have obligations and financial incentives to invest efficiently in their networks. The Regulatory Test requires that network investment must be justified economically on the basis of meeting standards for reliability, or on the basis of delivering net market benefits. Any investment required by a particular generator over and above this must be funded by the generator itself (or the generator must accept the consequences in terms of dispatch risk). This is an important form of locational signal. The planned reforms to the Regulatory Test and the establishment of a NTP, as part of the implementation of national transmission planning arrangements, will improve the effectiveness of this form of signal.

- *Fuel access and transport costs*—other things being equal, a generator that is located close to its fuel source will be more competitive than a generator that incurs significant costs in transporting its fuel to its generating station. The relative cost of transporting fuel, as compared to locating at the fuel source and transmitting the generated electricity greater distances, is another form of location signal. Clearly, this is more relevant to some generating technologies (e.g. gas) than others (e.g. wind).

The locational signals provided through the CM Regime, including the prospective reforms to the Regulatory Test and the establishment of a NTP, play an important role in influencing decision-making by market participants. In addition, these factors may indirectly or directly influence investment decisions, for example whether to finance a project and, if so, what project and at what cost. It is how these signals combine, rather than the form or strength of a particular signal on its own, that matters when assessing their impact on the efficiency of outcomes for consumers.

3.2 Recommendations for change

In the following sections, we summarise our recommendations, explain how they incrementally improve the CM Regime and propose how to implement them.

3.2.1 Dispatch

Recommendations

We are recommending that the Rules be amended to clarify and strengthen the obligations on NEMMCO in respect of how it formulates the constraints used to dispatch the market. We are also recommending improvements to the provision of information to the market about events affecting dispatch.

With these changes, the Rules will require NEMMCO to:

- use a fully co-optimised network constraint formulation when dispatching the market, unless during pre-defined exceptional circumstances in which cases it can use an alternative constraint formulation (ACF);
- develop Constraint Guidelines for constraint formulation, constraint use and the policy for managing negative settlement residues;
- comply with the Constraint Guidelines; and
- publish in a Congestion Information Resource (CIR) any information about "planned network events"[20] that will materially affect network constraints.

We are also recommending that the Rules allow NEMMCO to intervene in dispatch to manage the accumulation of negative settlement residues, conditional on NEMMCO identifying its policy for intervention, including the trigger level which we recommend should be set at $100 000. We will review this policy and evaluate the further need for this intervention in three years.

Context

NEMMCO is both the system operator and the market operator. In its capacity as system operator, NEMMCO has the role of determining the volume of output of each generator at each point in time. This is the dispatch process. NEMMCO calculates the dispatch and communicates instructions to each generator (and large load) every five minutes.

The objective of the central dispatch process specified in the Rules is to maximise the value of trade in the spot market, subject to the constraint of maintaining the security and reliability of the power system.[21] This translates into an objective of minimising the total cost of dispatch based on the value of bids and offers. Implicit in this is an assumption that bids and offers accurately convey information about the cost of production and the value of consumption.

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[20] Planned network events include: network outages; commissioning (or decommissioning) of new generating units, load or network assets; and new or modified network support agreements.

[21] The central dispatch objective is set out in clause 3.8.1 of the Rules.

A dispatch solution must be technically feasible. This means that the underlying physical network must be able to manage the resultant electricity flows and that NEMMCO's instructions to individual generators and large users must be consistent with their operating characteristics.

Constraint equations provide mathematical descriptions of the physical network. They explain how different variables, such as generator output, in the market affect flows across the network. NEMMCO uses constraint equations in the dispatch process and changes them to reflect changes in the available network. The process of designing constraint equations is known as constraint formulation. A "fully co-optimised" formulation is a form of constraint that gives NEMMCO the ability to control the most number of variables in the dispatch process.

In its capacity as market operator, NEMMCO performs the task of financial settlement. This is the process of paying generators for what they produce and billing users for what they consume. Producers and consumers within a region are settled at the same price, although different prices might exist between regions. In any given trading interval there can be net flows between regions. For example, the New South Wales region might be a net importer of electricity from the Queensland region. Ordinarily this will occur when the price in the New South Wales region is higher than the price in the Queensland region. In this scenario NEMMCO receives more money from consumers (in NSW) than it pays to producers (in Queensland). This difference creates an "inter-regional settlement residue" (IRSR).

In some circumstances, however, the dispatch might produce an outcome in which electricity flows from a higher-priced region to a lower-priced region, for example as a result of network constraints within a region. This will create a "negative" settlement residue. Negative settlement residues can adversely impact the ability of participants to trade efficiently across regions. The current arrangements provide for NEMMCO to intervene in the dispatch in some circumstances to manage the accumulation of negative settlement residues.

Reasoning

Clear Rules on dispatch mean that NEMMCO has a structured framework to operate under and that market participants have a better understanding of the dispatch process. A transparent and predictable central dispatch process provides certainty for generators and large customers, enabling them to make informed decisions on their bids and offers so as to manage perceived dispatch risks.

Our recommendations will improve the clarity of the dispatch process. They will provide greater transparency and predictability around the formulation, development and use of constraint equations. Constraint equations have a significant commercial impact as they can directly affect how generation and load are dispatched. By "hardwiring" the constraint form in the Rules and requiring a high degree of transparency and predictability around the development and use of constraint equations through the Constraint Guidelines, our recommendations will ensure that market participants have greater certainty as to how these factors will impact on their own dispatch.

Use of the fully co-optimised constraint formulation is a policy position endorsed by the MCE.[22] This particular formulation gives NEMMCO control over the most number of dispatchable variables (e.g. generator output), which improves its ability to manage power system security and supply reliability and to utilise more fully the network during the dispatch process. There are certain circumstances under which NEMMCO considers a constraint formulation that is not fully co-optimised (an ACF) will deliver greater security in the power system. While it is important for the system operator to have a level of flexibility in the Rules to use an ACF, participants must also have certainty around what constraint formulation NEMMCO will use in dispatch. This is why we recommend that NEMMCO should use an ACF in exceptional circumstances only, and that those exceptions should be explicitly identified beforehand in the Constraint Guidelines.

It is also important for generators and large customers to have certainty and predictability in circumstances where NEMMCO may intervene in dispatch. In general terms, physical interventions are inherently problematic and should, if possible, be avoided. Our recommendation to enable NEMMCO to intervene in dispatch to manage negative settlement residues is therefore sub-optimal. However, while NEMMCO's intervention is not an ideal response to counter-price flows, removing the intervention altogether could greatly distort generator bidding incentives. This has implications for risk management, as discussed below.

To provide the greatest certainty and predictability around this intervention, NEMMCO must set out its policy for when and how it will intervene in the market to manage negative settlement residues in the Constraint Guidelines. This includes setting its intervention threshold. We are recommending that this threshold should increase from \$6 000 to \$100 000, to reduce uncertainty for participants around excessive intervention in dispatch and to allow, in most cases, efficient dispatch to continue by delaying intervention. We will review NEMMCO's intervention policy in three years' time to assess whether we can remove it.

Lastly, generators and large customers can make more informed bids and offers if they have better information about which constraint equations will be included in dispatch improves participant decision-making. The recommended CIR will provide the most up to date information on network outages and other planned network events. This will provide participants with a better understanding of how potential changes in system conditions are likely to affect network constraints and therefore influence dispatch. This translates into more informed and efficient decision-making for participants.

Implementation

The *Draft National Electricity Amendment (Fully co-optimised and alternative constraint formulation) Rule 2008* (Constraints Draft Rule) articulates how to implement the recommendations for constraint formulation and the management of negative

[22] See the MCE's May 2005 Statement of NEM Electricity Transmission for more information.

residues.[23] It will formalise NEMMCO's use of fully co-optimised constraints and will set out the information NEMMCO must include in its Constraint Guidelines. This will include outlining its policy for managing negative settlement residues and ACF.

The establishment of the CIR is set out in the *Draft National Electricity Amendment (Constraint Information Resource) Rule 2008* (CIR Draft Rule).[24] This Draft Rule will require NEMMCO to develop and publish a resource that provides information in a cost effective manner to market participants to enable them to understand the patterns of network congestion and make projections of market outcomes in the presence of network congestion. This will include information on planned network events. The development of the CIR is to be continuous and incremental.

A Rule change is not necessary to increase the threshold trigger to manage negative settlement residues. NEMMCO can implement this through a change in its dispatch operating procedure. However, the threshold should not be increased prior to implementing the new recommended negative settlement residues recovery mechanism, discussed below in Section 3.2.3.

For more details on the implementation of these recommendations, see Appendix C. The Constraints Draft Rule and CIR Draft Rule are published in Appendix G.

3.2.2 Transmission access, pricing, incentives and investment planning

Recommendations

In 2006 we reviewed and substantially reformed the regulatory framework for transmission. In this Congestion Management Review we have considered whether further refinement is required, bearing in mind that the new regulatory framework has not been in operation for long enough to be able to assess its effects properly.

We have identified one area where amending the Rules will clarify and strengthen the framework. This relates to circumstances in which generators choose to fund a network augmentation in the context of negotiating its connection service with a TNSP.

Our recommendation is to make explicit the requirement that recouped costs (or reduced charges) should be negotiated between a generator and a TNSP and should apply to circumstances where another party connects to the network and benefits from an existing participant-funded network augmentation.

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23 The Constraints Draft Rule is published in Appendix G.

24 The CIR Draft Rule is published in Appendix G.

Context

Transmission services and revenue regulation

Chapters 6 and 6A of the Rules address the economic regulation of transmission services. They set out the provisions for determining TNSP revenue allowances and pricing methodologies. These provisions seek to create appropriate financial incentives to support efficient decision-making by both TNSPs and participants in relation to investment in transmission, generation and load facilities.

The Rules classify transmission services into two broad categories – Prescribed Transmission Services and Negotiated Transmission Services. The provision of Prescribed Transmission Services is subject to a revenue cap, set every five years by the AER pursuant to a process defined in the Rules. The revenue cap is set to permit recovery, during the regulatory period, of depreciation and a reasonable rate of return on: (a) actual capital expenditure incurred before the start of the regulatory period; (b) a forecast efficient level of capital expenditure to be incurred during the regulatory period; and (c) a forecast efficient level of operating expenditure.

Revenue for TNSPs from the provision of Negotiated Transmission Services is not subject to a cap. The provision of new Connection Services is the main form of Negotiated Transmission Service. The Rules also provide for negotiated transmission network user access. The negotiation between a generator and a TNSP can include a generator agreeing to fund a network augmentation. A generator might do this if the network provided by TNSPs under the regulated incentives delivers an unacceptable (for the generator) level of dispatch risk. The Electricity Transmission Network Augmentation Connection Guidelines currently published by VENCorp provide further detail on how these arrangements can work in practice under the current Rules.[25]

The Rules set out a framework and principles for setting prices for Prescribed Transmission Services. They also set out principles for negotiating access for Negotiated Transmission Services. The Rules maintain a "shallow" connection charge approach for new generation. This means that generators pay charges related to the cost of the assets required to enable the electricity they generate to be exported on to the main interconnected network. The cost of the main interconnected network is recovered through charges levied on consumers.

In related work, we are currently reviewing the framework for transmission incentives from the perspective of incentives for TNSPs to explore and implement non-network (e.g. demand-side) options where they are more efficient than options based around transmission investment. We recently published an Issues Paper on demand-side participation in the NEM.[26]

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25 http://www.vencorp.com.au/index.php?action=filemanager&folder_id=581&pageID=7770&sectionID=8246

26 AEMC 2008, Review of Demand-Side Participation in the National Electricity Market, Stage 2: Issues Paper, 16 May 2008, Sydney. Available: www.aemc.gov.au.

Transmission planning

A TNSP is responsible for investment planning in its area. The Rules stipulate a process of consultation and assessment that must be followed before investment is undertaken. This is the Regulatory Test. To satisfy the Regulatory Test, investment proposals are required to meet reliability needs or to deliver net benefits to the market. As noted in Appendix C (C.3.4), we are currently developing proposals to reform the Regulatory Test as it applies to transmission companies. These reforms, which are being undertaken at the direction of the MCE, will amalgamate the reliability and market benefits elements of the Test and establish a common framework for assessing costs and benefits across all projects.

We are also developing recommendations for the MCE on establishing a NTP. The NTP will publish information, including an annual NTNDP, setting out strategic, long-term development plans under a range of scenarios. This will not alter the accountability of individual TNSPs, but it will enhance the information available to TNSPs in undertaking their planning. This is likely to promote a more coordinated approach to the development of the NEM's transmission network over time.

The Rules also provide a "safety net" in the event of planning failure by a TNSP. This is the LRPP. The LRPP empowers us to oblige a TNSP to apply the Regulatory Test.

Reasoning

Negotiated transmission services are an important element of the overall CM Regime because they provide locational signals to generators considering investment options. The direct cost of connection provides one form of signal. The scope for generator-funded network augmentations provides another. This has relevance where the quality of access required by the generator is greater than can be supported by network investment consistent with satisfying the Regulatory Test.

A potential barrier to efficient responses to these signals is the risk that a generator who funds a network augmentation does not realise the full benefits of the augmentation because another generator connects subsequently. This is the "first mover" problem. The Rules provide for this contingency in two ways. First, they allow a generator to negotiate an explicit level of transmission network user access with a TNSP; for example, the generator could stipulate compensation payments if the level of service was reduced. Second, they allow costs to be recouped (or charges reduced) in the event that another user's connection impacts on the service being provided to the "first mover".

While the current provisions in the Rules already allow for such responses to subsequent connections to a "first mover"-funded augmentation, our analysis indicates that these provisions can be stated more clearly and directly. This includes making explicit the requirement that recouped costs (or reduced charges) should be negotiated between a generator and a TNSP, and not unilaterally imposed by a

TNSP.[27] We believe this clarification will provide greater certainty for generators, thereby improving the overall effectiveness of the locational signal.

A number of stakeholders made submissions on the current operation of this area of the Rules, citing a number of weaknesses. The National Generators Forum (NGF) also submitted consulting work undertaken for them by Synergies, which set out different models of transmission access. While we acknowledge and welcome the points made in submissions, the adoption of alternative models for transmission access would represent significant change to the NEM market design which we do not think can be supported on the basis of the current evidence on materiality. Such models might, however, have relevance to the longer-term development of the CM Regime, as discussed in the next chapter.

Implementation

The *Draft National Electricity Amendment (Network Augmentation) Rule 2008* (Network Augmentation Draft Rule) makes two amendments to the Rules to implement this recommendation.[28] The first is to include a drafting note in clause 6A.9.1(6) to clarify a point about adjustments in the costs for transmission access: where a network augmentation now provides a service to another party, costs can be recouped from that other party.

The second is to introduce a new clause 5.4A(f)(3) to clarify the point that when a generator and a TNSP are negotiating transmission access, including use of system charges, these negotiations should be conducted in a manner consistent with clause 6A.9.1.

The Network Augmentation Draft Rule is published in Appendix G.

3.2.3 Risk management instruments

Recommendations

We are recommending that the Rules be amended to change the method of funding negative settlement residues. Rather than being netted-off against positive settlement residues within the same billing week, and then any outstanding amount being recovered from Settlement Residue Auction (SRA) proceeds, they should be recovered directly from the importing region's TNSP. We are also recommending changing the design of the SRA so that auction units will be available up to three years in advance. The release profile of the quarterly units will be determined by the SRC.

27 The recommendation makes explicit the link between the principles for negotiating transmission network access under clause 6A.9.1 of the Rules and the rules on access arrangements for transmission networks in rule 5.4A.

28 The Network Augmentation Draft Rule is published in Appendix G.

Context

In the NEM's regional market, there is no price separation (and therefore no basis risk) within a region. Generators, large users and retailers contracting across regions, however, do face basis risk. These participants make use of financial contracts such as capacity swaps to manage this inter-regional risk. They can also purchase units to the IRSRs that arise when electricity flows between regions and the prices in those regions differ.[29] These IRSR units help fund any hedging contract payment shortfall that arises from inter-regional prices differences.

NEMMCO sells IRSR units every quarter at the SRA. Currently, SRA participants can bid for units up to one year in advance. There are units for every regulated interconnector in the NEM, in both directions. This enables participants to hedge price differences between all regions in both directions. The single exception is Tasmania where there are no IRSRs attributable to flows between Tasmania and Victoria.[30]

As discussed in section 3.2.1, dispatch can sometimes result in flows from a higher-priced region to a lower-priced region, resulting in negative settlement residues. The current funding mechanism for these negative settlement residues reduces the value of IRSR units as an inter-regional hedging instrument. Negative settlement residues are netted-off positive settlement residues within the same billing week for each same-direction interconnector. This reduces the positive residues available for distribution to unit holders.

If any negative settlement residues remain after the netting-off, they are recovered from SRA proceeds for the same-direction interconnector. SRA proceeds are what participants pay for IRSR units. TNSPs receive these proceeds to offset transmission charges.

Reasoning

Our recommendations all seek to improve the usefulness of the IRSR unit as a hedging instrument for generators, retailers and large users. The first recommendation will remove an arbitrary distinction in the Rules between funding negative settlement residues which occur in the same billing week as positive settlement residues, and funding those which do not occur in the same billing week. Removing this intra-week netting-off means that unit holders will retain the full value of residues accumulated from other events during a week, which will thereby improve the IRSR as a risk management instrument. The value of IRSR units will no longer be diluted because of events resulting in negative settlement residues.

Directly billing the relevant TNSP, who will then recover these costs through charges to its customers, is a more direct and transparent way to recover negative settlement

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[29] The value of these residues is equal to the price difference between the regions times the flow between the regions.

[30] Tasmania is connected to the NEM through a Market Network Service Provider (MNSP), which is not regulated. There are no IRSRs attributed to flows across Basslink.

residues than via auction proceeds, as is currently the practice—although the net impact is broadly the same. This direct billing arrangement gives NEMMCO the flexibility to recover negative settlement residues in a timely manner rather than having to wait for the quarterly auctions.

These changes, coupled with an increase in the dispatch intervention threshold to manage the accumulation of negative settlement residues, will improve the value and usefulness of the IRSR unit as a mechanism for managing inter-regional basis risk.[31]

The redesign of the SRA to sell units up to three years in advance will improve their flexibility and usefulness for participants seeking hedge cover for their longer-term contract positions. It will potentially make secondary trading more likely, and thereby improve liquidity in the range of risk management tools available in the NEM.

Other important factors for strengthening the value of IRSR units are improving the reliability and predictability of transmission capability. If participants can accurately predict interconnector transfer limits, then with a high degree of certainty they can determine the required number of IRSR units necessary to hedge an inter-regional position. The CIR will provide information to participants to help them understand how the network's available network capability may change due to planned network events such as outages. Also, the NTP will be responsible for reporting on network capability as part of its NTNDP, which will provide an additional information resource for participants.

Implementation

The *Draft National Electricity Amendment (Negative Inter-regional Settlements Residue Amounts) Rule 2008* (Negative Residue Draft Rule) sets out the requirement for NEMMCO to recover negative settlement residues from the appropriate TNSP in the importing region.[32] Determining the appropriate TNSP to be charged will be the responsibility of the AER. This Rule will also enable NEMMCO to set a new TNSP settlement cycle for recovering negative settlement residues. This is to ensure that NEMMCO can recover the negative settlement residues from the appropriate TNSP in advance of the normal market settlement day, thereby preventing any potential shortfalls should the TNSP be late or miss a payment.

NEMMCO has confirmed that the process of extending the auctioning of IRSR units by three years is a procedural matter for it and the Settlements Residue Committee to consider. Therefore, no amendment to the Rules is necessary to implement this change.

NEMMCO has stated that in June 2008 it will start auctioning units for Q3 2009 (July–September 2009). The current negative settlement residues recovery

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31 The recommendation to increase the intervention threshold from $6 000 to $100 000 is discussed above in section 3.2.1.

32 The Negative Residue Draft Rule is published in Appendix G.

mechanism is due to expire on 30 June 2009. In our view, it would be inefficient to consider reverting to the old recovery mechanism of auction fees when we are recommending a variation of the existing recovery mechanism. Therefore, it would be appropriate to extend the current sunset until the recommended new recovery mechanism can be implemented. We could give effect to this in the form of a savings and transitional arrangement in the Negative Residue Draft Rule.

For more details on the implementation of these recommendations, see Appendix C. The Negative Residue Draft Rule is published in Appendix G.

3.2.4 Wholesale market pricing and settlement arrangements

3.2.4.1 Information

Recommendations

We are recommending that the Rules be amended to require NEMMCO to publish analysis on the extent and pattern of "mis-pricing" caused by congestion and to update this analysis regularly. This information will form part of the recommended CIR.

Context

Information on mis-pricing represents a useful, robust measure of the incidence of congestion, which is specific to individual points on the network. In undertaking this Review, we requested NEMMCO to undertake detailed analysis of mis-pricing, which in turn informed the development of our recommendations. The NEMMCO analysis was published with the Draft Report.

Reasoning

The availability of information plays an important role in enabling market participants to understand, and therefore manage, the risks associated with congestion. The analysis undertaken by NEMMCO provided useful insights into the nature of prevailing patterns of congestion under system normal conditions and non-system normal conditions (e.g. in the presence of outages). Understanding patterns and trends in the incidence of congestion is also relevant to policymakers.

We therefore think that the analysis undertaken and published by NEMMCO especially for this Review should be updated and published on a regular basis. Incorporating this requirement into the recommended CIR will mean that the precise form this analysis takes can be refined over time in the light of stakeholders' views.

Implementation

The CIR Draft Rule (mentioned earlier in section 3.2.1) also requires NEMMCO to publish information on the incidence of congestion using historical data on mis-pricing.[33] It also clarifies the definition of mis-pricing, based on comments made in submissions to the Exposure Draft.

For more details on the implementation of this recommendation, see Appendix C. The CIR Draft Rule is published in Appendix G.

3.2.4.2 Generator constrained-on payments

Recommendation

We are not recommending implementation of a constrained-on payments regime through changes to the Rules on settlement of the spot market. This is because it would not represent a proportionate means of improving the management of physical and financial trading risks arising from network congestion.

Context

A generator is constrained-on if it is dispatched at a level of output above what it is willing to supply at the prevailing RRP. In other words, it values its generation at a price greater than what it will receive. It is an example of mis-pricing. This can occur as a consequence of the dispatch process. If a generator's output can help relieve a constraint, and thereby enable cheaper generation from elsewhere to supply load at the RRN, then that generator may be dispatched, despite its bids being above the RRP. While the market as a whole may be better off, the generator constrained-on may not be.

It has been proposed that a constrained-on generator could be compensated by a form of congestion pricing that would supplement its settlement price above the RRP. This is known as a "constrained-on payment".

Reasoning

While constrained-on payments would address one type of mis-pricing in the NEM, they raise several concerns. First, imposing a constrained-on payment regime through the pricing and settlement arrangements may be viewed as pre-empting a transmission response under Chapter 5 of the Rules.

Second, constrained-on payments may create the scope for the exercise of transitory market power by constrained-on generators, especially where a generator owns a portfolio of plant around a transmission loop. For example, take a congestion pricing scheme, such as a CSP/CSC mechanism, which would be equivalent to a pay-as-bid settlement approach for the volume of output being constrained-on. Potentially acute pockets of transitory market power could arise because generators' bids would affect the price they receive.

[33] The CIR Draft Rule is published in Appendix G.

There is also the question of how to fund constrained-on payments. Most constrained-on payment regimes need an external funding source to cover the payments.

An alternative scheme would be for generators constrained-on through the dispatch process to receive compensation as if NEMMCO had directed them generate. This could address the concerns about potential market power because the constrained-on payment would not be based on the value of the bids for the volume of output being constrained-on. Rather, the compensation would be based on a pre-determined calculation, which could be based on costs, or agreed to in a negotiate-arbitrate framework. Nevertheless, the need to source external funding for the payments would remain.

Finally, on the key issue of materiality, historically there has been a lower incidence of constrained-on generation than constrained-off generation. For example, for the three years from 2002/03 to 2005/06 there were on average around 40 connection points in the NEM that were constrained-on—about half the number that were constrained-off. This evidence does not support a case for change at this time.

In addition, there is evidence that the existing transmission responses are working effectively. The contractual arrangements between generators and TNSPs being used in the context of network support provide incentives for generators to generate when they otherwise may not have generated.

3.2.4.3 Location-specific interim constraint management mechanisms

Recommendations

In order to improve the management of physical and financial risks associated with congestion, the MCE's Terms of Reference requested that we develop a location-specific interim constraint management mechanism. The aim of such a mechanism is to provide an immediate (and temporary) "fix" to a material constraint until it can be addressed permanently through investment or region boundary change. We have carefully considered this type of mechanism, but we are not recommending that it be implemented as a permanent fixture of the NEM's regulatory framework.

Context

The MCE requested that we develop a location-specific interim constraint management mechanism as a way of improving the ability of participants to manage the physical and financial risks arising from network congestion. The MCE also required us to take into account the detailed work undertaken by CRA on these issues, as well as the trial arrangements in place in the Snowy region.

Generic framework for location-specific interim constraint management mechanisms

There is a wide range of detailed designs for a location-specific interim constraint management mechanism, and they are all based on a common framework.[34] The framework involves isolating a particular network constraint (or related set of network constraints) and amending the rules for calculating prices in the wholesale market in the event that the constraint binds.

If a constraint binds, then the cost of supplying demand at different locations can vary. This is because a binding constraint might limit the ability to use a cheaper source of generation to serve demand at one location, but not at another location. Cost-of-supply variations between RRNs are reflected in RRPs. But cost-of-supply variations between RRNs and other locations within the same region are not reflected in wholesale market prices. A location-specific interim constraint management mechanism introduces the possibility that cost-of-supply differences relating to particular network constraints will be reflected in prices in the market.

A location-specific interim constraint management mechanism works by removing the arrangement whereby a generator is settled automatically at the RRP for its dispatched volume of output. Instead, under the mechanism a generator is settled at a price more closely aligned to the cost-of supply at the generator's specific location. The degree of alignment depends on the range of network constraints included in the particular location-specific interim constraint management mechanism.[35]

In addition, the mechanism also generally involves the allocation of pre-defined "rights" to receive the RRP for specified levels of output. These rights can, depending on the design of the mechanism, be allocated according to a pre-defined administrative rule, for example as a fixed percentage of the available capacity, or through a market mechanism such as an auction.

The collective impact on a generator subject to a location-specific interim constraint management mechanism is, therefore, that it will receive the RRP up to a specified output limit and then be exposed to a price more closely related to the local cost of supply (its "nodal price").

Experience from the Snowy trial

A location-specific interim constraint management mechanism has been applied on a trial basis in the Snowy region since 1 October 2006. Having analysed this trial as part of our assessment of a range of Rule change proposals relating to congestion in the Snowy region, we established that the mechanism promoted more efficient outcomes only in circumstances specific to that region. The experience of the Snowy trial is not readily transferable to other parts of the NEM, for these reasons:

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34 Gregan, T, and E Grant Read, "Congestion Pricing Options for the Australian National Electricity Market: Overview", prepared for the AEMC, February 2008. Available at: www.aemc.gov.au.

35 At the extreme, if the mechanism included all network constraints at all times, then it would approximate to calculating a separate price for each location (or "node") on the network.

- In the Snowy region the congestion problem was enduring and stable. It reflected a significant constraint between Murray and Tumut that could not be addressed by either network or generation investment for topographical reasons and because the area is a national park. In contrast, NEMMCO's mis-pricing analysis from 2001/02 to 2005/06 indicated that patterns of congestion in other parts of the network have been transitory, including a large (and growing) proportion of mis-pricing occurring at times of network outages.
- The Snowy trial also involved only one generating company. Hence, design issues relating to the allocation of rights to be settled at the RRP across competing parties did not need to be addressed.

In conclusion, while the Snowy trial provides useful context for some of the issues involved in assessing the case for location-specific interim constraint management mechanisms more generally, it has limited applicability.

Reasoning

We have sought to assess the costs and benefits of introducing a location-specific interim constraint management mechanism with reference to the National Electricity Objective of promoting economic efficiency and a stable, proportionate regulatory regime.

Scope for greater productive efficiency

The benefit of a location-specific interim constraint management mechanism is that it strengthens incentives for generators to submit bids which are reflective of costs. This reduces the problem of dis-orderly bidding in the market, i.e. generators using bidding as a means of managing dispatch risk. Dis-orderly bidding can be a source of productive inefficiency. The lack of cost-reflective bidding in the presence of congestion can increase the overall costs of meeting demand.

However, our analysis indicates that the productive inefficiency costs associated with dis-orderly bidding have been relatively low. The analysis undertaken for this Review by Frontier Economics and published with our Draft Report indicated that productive inefficiencies were in the order of $8 million per year (for the 2007/08 financial year).

Greater complexity in managing basis risk

A location-specific interim constraint management mechanism reduces incentives for dis-orderly bidding. This has an indeterminate impact on aggregate dispatch risk. In some cases, dis-orderly bidding can deliver relatively predictable dispatch outcomes, for example because of the application of "tie-breaking" rules in instances where all generators bid the same price. In other cases the potential for dis-orderly bidding can increase perceptions of dispatch risk, for example because of errors in predicting when dis-orderly bidding is likely to occur.

However, the introduction of a location-specific interim constraint management mechanism unambiguously adds to the complexity of managing basis risk. It increases the number of potential prices in the market. A generator subject to a location-specific interim constraint management mechanism therefore has to manage the risk of price separation between RRPs, and between its location and its RRP. This might be a particular challenge when a generator has entered into a contract prior to a location-specific interim constraint management mechanism being implemented. The materiality of this impact depends in part on the form of the instruments created as part of a location-specific interim constraint management mechanism for managing this risk, for example the form of the right to be settled at the RRP.

Significant implementation issues

To establish location-specific interim constraint management mechanisms more pervasively in the NEM requires the resolution of two significant implementation issues. (The experience of the Snowy trial is of limited value in this regard, due to its uniqueness.)

First, how should the constraints be identified to which the mechanism should be applied? NEMMCO's analysis of the prevailing patterns of congestion in the NEM shows that much congestion has been transitory (including a large proportion which coincides with network outages). In this context, even if the relevant constraints could be clearly identified, the mechanism would need to be implemented at short notice in order for it to be beneficial. The short notice period to implement would probably exacerbate the challenge of managing basis risk in the presence of such a potential mechanisms. The MCE recognised the potentially disruptive inputs of change to the pricing and settlement arrangements by requiring that a region change could only be implemented with three years notice.

Second, how should the entitlement to be settled at the regional rather than the local price be allocated across the range of potential parties subject to a specific mechanism. Under the current NEM design, these entitlements are allocated implicitly to match dispatch volumes. A location-specific interim constraint management mechanism would require an alternative method of allocation. How these entitlements are allocated will impact on the ability of market participants to manage basis risk in the presence of a mechanism. There are two broad approaches that could be adopted:

- *Administrative rule.* The mechanism could use a pre-defined rule, for example pro-rated shares of the available constrained capacity. The rule would also need to allow for the possibility of including newly-connected generators in the mechanism.

- *Market mechanism.* The mechanism could define new financial instruments that would provide rights to be settled at the RRP, and release them for sale, for example through periodic auctions.

There are challenges with both of these approaches. An administrative rule runs the risk of replacing one set of incentives for inefficient behaviour (e.g. dis-orderly bidding) with another. For example, a method based on pro-rated shares of each generator's available capacity might sharpen incentives for generators to overstate their available capacity, which might compromise NEMMCO's ability to operate the system efficiently.

The treatment of new generators is also a challenge. Some stakeholders have suggested that a location-specific interim constraint management mechanism should allocate available network capacity between existing generators, with new generators being settled at the local price for all of their output. This would skew the Rules in favour of existing generators, and potentially affect the efficiency of the competitive process. It might be more efficient (e.g. due to proximity to fuel source) for a new generator to connect at a congested part of the transmission network. A location-specific interim constraint management mechanism could, therefore, create new types of barriers to new entry, for example by creating additional basis risk, but no tools for managing it (other than through secondary trading with incumbent generators, if that were permissible under a location-specific interim constraint management mechanism).

In contrast, a market-based approach to allocating financial rights under a location-specific interim constraint management mechanism would not raise the same competition issues as an administered rule, but would involve significant additional complexity for market participants. In a relatively simple congestion management mechanism such as the Snowy trial, the number of constraints involved is large. If there were individual auctions for financial rights in each constraint, then there would be a significant number of auctions. There is an implementation cost to establishing the infrastructure to support such financial instruments, as well as a compliance cost for market participants.

Limited impact on locational signals

A location-specific interim constraint management mechanism would address disorderly bidding. However, the benefits in terms of greater productive efficiency would be, based on the evidence, relatively low. It could also impact the management of basis risk, and it would require the resolution of a number of significant implementation issues. There might, nevertheless, be net benefits from such a mechanism if there were evidence of other classes of benefit, for example if the mechanism's presence contributed to dynamic efficiency, i.e. the efficiency of decision-making (including investment decisions) over time.

As discussed above (section 3.1), under the current NEM design and Rules there is a range of locational signals. We are not persuaded that a location-specific interim constraint management mechanism would strengthen or clarify these signals. This is because such a mechanism is uncertain and temporary in application. Hence, the pricing outcomes that might result from its implementation are also uncertain. When prospective investors make decisions to invest, they will not generally know whether or not (or how) a particular project will be affected by a location-specific interim constraint management mechanism. It could also be argued that uncertainty as to whether a project will be priced regionally or locally (for an unspecified period of time) would reduce the clarity of existing locational signals by creating more regulatory "noise". Under either scenario, a location-specific interim constraint management mechanism would not improve locational signals for investment.

In addition, a location-specific interim constraint management mechanism may also add to the uncertainty of power project financing by compromising the ability of participants to access financing for investment purposes. While not specifically a locational decision factor, this directly affects whether or not investment will take place.

4 Ongoing evolution of the NEM's CM Regime

4.1 Where this Review concludes

The recommendations made in this Final Report deliver, in our view, an effective and proportionate response to the prevailing patterns and economic materiality of congestion in the NEM. They represent an important first step in the CM Regime's ongoing evolution.

Our recommendations in this Review complement other significant reforms to facets of the CM Regime: the abolition of the Snowy region; the new process for region change; the Last Resort Planning Power; the framework for economic regulation for transmission; and the establishment of national transmission planning arrangements. Collectively, this represents a significant package of reforms which supports efficient outcomes consistent with the National Electricity Objective.

4.2 Future market development

Prospective policy changes, most notably an Emissions Trading Scheme (ETS) and an extended Mandatory Renewable Energy Target (MRET), are likely to have significant impacts on the underlying economics of the market, and therefore behaviour in the market. These policy changes are occuring at a time of general tightening in the balance between supply and demand, which, in any event will require significant new investment in generation and network capacity. In this context, an important question will be whether the current Rules and regulatory framework continue to represent an effective and proportionate means of promoting efficient outcomes, given the potential changes in behaviour. This question encompasses the CM Regime and its effectiveness, if the pattern and economic impacts of network congestion change substantially.

There remains significant uncertainty about the detailed design of the ETS. It is therefore too soon to conclude on what, if any, consequent changes might be required to the Rules and regulatory framework to continue to support efficient outcomes. Hence, we have not sought to identify additional recommendations in this Final Report. Rather, we have sought to outline some of the potential impacts resulting from policies such as ETS and MRET and set out our views on the need for future review processes. This is consistent with our role under the National Electricity Law in respect of market development.

It is important and appropriate to consider these potential impacts in a broad context. The implications for the Rules include, but are wider than, the details of the CM Regime. There are many interactions between changes to the CM Regime and changes to other aspects of the regulatory framework, and partial assessment runs the risk of unintended consequences and less efficient outcomes.

This chapter considers these issues in more detail and highlights interactions between other related policy initiatives, such as the establishment of a National Transmission Planner and reform of the current Regulatory Test for transmission investment decisions. It also documents some of the options which might have relevance to this debate, including options for change which have been raised by stakeholders through the course of this Review but which, in our view, fell outside its scope.

4.3 Interactions between climate change policies and the NEM

This section sets out our initial thoughts on the main areas of interaction between climate changes policies, and behaviour and outcomes in the NEM. Further work and policy definition is required to analyse these interactions fully, for example to identify potential weaknesses in the Rules or regulation framework.

4.3.1 Merit order and dispatch

The merit order is the cost ranking of generators. If generator bids reflect costs, then the merit order will be reflected in the dispatch; that is, whether and to what extent each generator operates at any point in time.

An ETS will increase the operating costs of generators in line with their CO_2 (carbon dioxide) emissions. In general, this will increase the costs of coal-fired plant more than it will the costs of gas-fired plant; the amount will vary depending on the fuel source, plant type and operations. This will improve the competitive position of gas-fired plant in the NEM, other things being equal. This might, however, be offset by higher gas prices (and therefore higher costs for gas-fired generators). Such a change is likely to increase the level of gas-fired generation when compared with scenarios without an ETS. It may therefore lead to a change in the merit order and to the displacement of coal-fired plant by gas-fired plant.

An MRET and ETS will also increase the penetration of renewable generation. A key component of this will be wind farms.[36] Typically, wind farms have high capital costs and low operating costs. They are also often highly contracted. These factors may increase their incentives to bid at very low prices. Intermittent generation, such as wind farms, is therefore likely to be one of the lower-cost forms of generation bid into the market. Historically, intermittent generation has been unscheduled. Essentially this means that the plant ran without its dispatch being centrally controlled to minimise costs or maintain network security. Recently the Rules have been changed to provide NEMMCO with a greater degree of control in the dispatch process over larger wind farms. Much larger volumes of intermittent generation operating high up the merit order are likely to create new challenges for system operation, such as the management of efficient levels of reserve and the procurement of ancillary services.

If the position of coal-fired generation in the merit order changes, this might also raise a number of issues. Much coal-fired plant is optimised to run almost continuously at stable levels of output. If in the future it were required to operate more intermittently than it has done in the past, this might give rise to technical

[36] A disproportionately large proportion of wind generation is located in South Australia and Victoria.

challenges and cost (and therefore price) implications which are as-yet unknown. It might, for example, affect the need for generation reserve, operating reserve and the efficiency of energy and FCAS markets.

4.3.2 Generation investment

Investment is generally underpinned by long-term contracts between generators and retailers or major consumers. Investment is also made on a merchant basis (that is, taking risk on future pool prices). In both cases investors require a reasonable ability to forecast costs and revenues. If high risk attaches to costs and revenues, then investors will require higher returns, or they will not invest.

Investors are familiar with managing risks such as price volatility, changes in contractor costs and changes in fuel prices. However, it is harder for investors to assess and price and manage risk associated with government policy change. One of the impacts of climate change policies is, therefore, the uncertainty they produce in the market while the detailed design of each policy is being determined and legislated.

The introduction of an ETS may benefit gas-fired generation. However, gas-fired generation faces downside risk from a rapid increase in renewable generation due to the MRET. It also faces pressure in terms of fuel costs given the alternative markets for gas (e.g. exporting as LNG), and transport costs and practicalities (e.g. extending the gas transmission network).

A large increase in renewable generation will also alter the way in which investors recover their capital costs. In an energy-only market, such as the NEM, capital costs are recovered and profits are realised through the differential between variable operating costs and system marginal price. In most cases renewable generation will have low or zero operating costs. It will therefore displace output from fossil fuel plant and reduce the energy output from that plant. Investors may require a higher energy price to recover capital costs, depending on their position in the merit order. It is currently difficult for investors to assess these impacts.

If levels of uncertainty result in the deferment of generation investment such that reserve levels become unacceptably low, then one potential impact is that NEMMCO will have to make more frequent use of market interventions, such as directions and the "Reserve Trader". The Reserve Trader is a form of market for capacity. If used more extensively, it might be necessary to review other forms of capacity market, such as markets for standing reserve.

4.3.3 Network investment

MRET will result in a large increase in new generation investment. The scale, location and timing of that increase will depend on decisions about scheme design, other economic signals in the market, and the practicalities of where it is feasible to build. (For example, opportunities for building new generation will be restricted by planning consent issues relating to environmental impacts on local communities).

The availability of wind and, where relevant, geothermal, solar and other renewable resources varies across the eastern seaboard. It is probable that some sites will have to be located at a long distance from load. It also seems probable that new wind generation will continue to be located in South Australia and Victoria disproportionately to other regions.

This raises the question of how to ensure efficient outcomes for investment in renewable generation. Issues include the costs of connection to the grid; the possible costs of grid reinforcement elsewhere; the impacts on network security of dispatch within security constraints; and the possible benefits from creating transmission links which can be used by other remote renewable generators.

The NEM currently makes use of regulated, negotiated and unregulated approaches to transmission investment. Regulated transmission revenues within a region are usually recovered through the region's transmission use of system (TUOS) charges. These arrangements determine how the risk of transmission investment being "stranded" is allocated between market participants and consumers. In broad terms, if a network investment satisfies the Regulatory Test, then the cost of the investment is underwritten by consumers (even if the investment proves, with the benefit of hindsight, to have been unnecessary). Investments that do not satisfy the Regulatory Test are, in effect, underwritten by the generator that contracts for them to be built.

The approach to charging out the costs of regulated investments may also need to reconsidered. If a disproportionate share of investment in remote renewable generation falls in South Australia and to a lesser extent in Victoria, this may raise efficiency and equity concerns if the associated transmission investment is funded by consumers in those States. This may require consideration of approaches to "inter-regional TUOS". We are currently consulting on this issue in the context of our review of national transmission planning arrangements.

A related set of issues includes the impact of renewables on planning of the overall transmission grid, and the interaction between new gas-fired generation, gas pipelines and transmission investments, notwithstanding the limitations on gas as a fuel source as discussed above. Both gas generation and gas pipeline investment are likely to be the result of private, "at-risk" decisions. However, the scale and speed of the investment required may be large and may therefore raise concerns about generation security. In addition these decisions will influence, and be influenced by, decisions on the transmission network.

4.3.4 Retail markets

The retail market relies on decentralised decision-making. Consumers are free to move between retailers, creating competition and incentives for retailers to meet consumer requirements efficiently.

Retailers in each jursidiction are required to supply energy to small customers at a regulated retail price.[37] To protect the smallest energy customers against ineffective competition, the prices charged by incumbent retailers in each region remain regulated at State level. We have been directed by the MCE to review the effectiveness of retail competition in electricity and gas retail markets (except in Western Australia[38]) and to provide advice on the future of retail price regulation.[39] Where we find that competition is effective, we provide advice on ways to phase out retail price regulation. We completed the review of Victoria in February 2008, and are now working on the review of the South Australian market.

Climate change polices may affect the efficiency of retail price regulation in two ways. First, they are likely to increase wholesale energy costs. Depending on the regulatory framework, it may not be possible to accurately forecast cost changes and reflect them in the regulated retail price. In the absence of a defined mechanism for cost pass-through, this could affect retail competition. It increases the likelihood of financial distress in the retail sector. This has implications for the generators that contract with these retailers. If retailers are unable to meet their contractual obligations, this can, in turn, affect the financial viability of the generator counter-party. While distress or insolvency is a legitimate risk in any market, including the NEM, it is more problematic when regulatory structures are a contributing factor.

Second, additional regulations applying to retailers (both host and new entrants) have been or are being introduced in response to climate change policies. These include MRET (and similar State-based targets which will be incorporated into MRET), energy efficiency targets, and a possible role in solar feed-in tariffs which are being mandated in several States.

The rationale for these measures is often the ability of retailers to cost effectively influence consumer behaviour. The measures may affect retailer costs and so, as with other climate change policies, may require regulatory pass-through. In so far as these schemes create administrative overheads, they may also act as a barrier to entry and reduce the effectiveness of retail competition.

4.4 Interactions with the CM Regime

The growing need for new investment resulting from the tightening supply/demand balance, and the changing cost structures resulting from policy responses to climate change are, collectively, likely to put new and different pressures on the CM Regime.

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37 There is one exception. From 1 January 2008, retail price regulation for small business customers in Victoria was removed.

38 The Economic Regulation Authority (ERA) of Western Australia is required to undertake the review for its jurisdiction at an appropriate time.

39 The Terms of Reference to these reviews is available on our website: http://www.aemc.gov.au/electricity.php?r=20080115.175820.

4.4.1 Locational investment decisions

The previous chapter described in some detail the range of signals that currently exist which inform investment decisions in the market. The implementation of ETS and MRET will alter the underlying economics of investment options for new generation capacity. It will boost the relative competitiveness of low-carbon, and in particular renewable, technologies and therefore make investment in these types of generation technologies more attractive. In the NEM's framework of open access to networks this is likely to reveal itself in a significant number of new applications for connection. This situation is magnified by the tightening supply/demand balance, which would require new investment in generation capacity in any event to ensure that demand continues to be met reliably and securely.

There is still significant uncertainty as to how, precisely, these new initiatives will impact on the underlying economics of investment decisions in the market. A key driver will be the extent to which the rights to emit carbon are allocated to existing generation capacity. It is therefore too soon (i.e. in this Review) to conclude that the current set of economic signals for investment are not sufficient to promote dynamic efficiency. This is particular so, given that climate change policy direction has only crystallised at the end of this Review process—after the Draft Report was published. While we could continue with the Review, in the light of these new developments, we see value in concluding the Review at this point but at the same time highlighting the potential need to continue to consider the case for further change through a different, more holistic process. The issues involved are wider than congestion management, and should be considered and assessed as such.

Potential further developments also need to be carefully considered in the context of other changes that are in train. For example, the establishment of a National Transmission Planner and the introduction of a new Regulatory Investment Test for Transmission will also affect the locational signals for investment in the market, and interactions between these reforms and any elements of the CM Regime need to be fully analysed before the case for further change can be determined.

We have an important role to play in contributing and focusing debate on these issues and in ensuring that the technical detail and impacts of different changes to the NEM design are visible and fully understood in the context of the wider policy debate on reducing Australia's carbon emissions and promoting renewable forms of generation. If there is a perceived need to sharpen locational signals in the market, then it is important that the different options are understood from the perspective of both theory and practical implementation.

In the previous chapter, we set out our reasoning as to why we are not persuaded that a location-specific interim constraint management mechanism, like CSP/CSC, will promote the National Electricity Objective, including strengthening locational signals, given the prevailing patterns and economic materiality of congestion at this stage. While in a location-specific and time-limited manner a constraint management mechanism does address the "dis-orderly bidding problem", its presence is unlikely to be the determining factor in investment decisions, and therefore it will not address the "location decision problem".

There is likely to be a wide range of reform options to be considered in response to analysis indicating that material transmission congestion will probably emerge as a consequence of changes to the underlying economics of the NEM. It might, for example, require re-evaluation of location-specific interim constraint management mechanisms as a transitional device, if new and stable points of material congestion emerge, for example as a result of timing differences between generator and network investment responses. Use of such a mechanism in this manner, however, would still require resolution of the outstanding design and implementation issues discussed in chapter 3 above. For example, individual applications of the mechanism would probably require a specific design for each location, because a generic model does not appear to be a practical option.

A more extensive reform option would be the introduction of Generator Nodal Pricing (GNP) on a NEM-wide basis. Compared to a location-specific interim pricing intervention, GNP would solve the dis-orderly bidding problem in a more predictable manner, and would be more effective at addressing the locational decision problem. This is because GNP would explicitly price all congestion in the NEM as it arises.

However, GNP represents a significant change to the NEM market design, and would require a complete overhaul of the market architecture for managing the price risk that every generator would now face. It consequently places much greater emphasis on the need for effective risk management instruments, such as Financial Transmission Rights (FTRs). As a companion piece to this Review, we have undertaken initial but substantial analytical work on the potential application of GNP. We commissioned Frontier Economics to undertake the initial work. The Frontier Economics report, and its review by Professor Grant Read of EGR Consulting, are published with this Final Report.[40]

4.4.2 New patterns of congestion

ETS and MRET impacts might also drive different dispatch outcomes. This will affect flows across the network. The bidding behaviour of generators, and changes to the merit order of dispatch, will happen more quickly than networks can respond. Similarly, we might observe new generation capacity connecting more quickly than the efficient downstream augmentation of the network can occur—a strong possibility given the relative lead times for new generation capacity and new transmission investment. This might result in new and different patterns of congestion, reflecting different sets of incentives for dis-orderly bidding.

In these circumstances, dis-orderly bidding might be more material in its effects than is presently the case. Further, changes in flows might result in new locations of pockets of systematic, enduring and material congestion, such as exists in the Snowy region. In these circumstances there might be a role for a localised, time-limited

40 Frontier Economics, "Generator Nodal Pricing – a review of theory and practical application", Report prepared for the AEMC, April 2008, Melbourne. Read, E.G., "Generator Nodal Pricing: Review of a report by Frontier Economics", prepared for the AEMC by EGR Consulting, 1 May 2008." Available on: www.aemc.gov.au.

intervention of the form trialled in the Snowy region. Note that in our analysis of the Snowy trial, the trial was shown to support more efficient outcomes than the status quo. On the other hand, more NEM-wide granular pricing would price congestion if and when it arises without the difficulties of implementing an individual pricing mechanism on an ad hoc basis. As discussed in chapter 3, however, introducing more granular pricing in the NEM has its own implementation issues.

The design of any option will need to be tailored to the specifics of the situation. The Rule change process is an appropriate mechanism for considering and implementing such an intervention, informed by the wide range of previous work (including Gregan and Read[41]). During the course of this Review, stakeholders presented a range of proposals. Some proposed significant change, like full CSP/CSC, while others proposed less substantial options for change focused on addressing dis-orderly bidding in the presence of congestion.

A recent proposal from a group of generators[42] is an example of the latter type. This proposal would retain the regional market design but, in the presence of congestion, would replace the existing right to settlement at the RRP with an alternative form of right that would eliminate incentives to bid in a dis-orderly manner. Babcock and Brown Power and Hydro Tasmania suggested similar arrangements. There may be scope to consider these less extreme options as a way of managing the dis-orderly bidding incentives that may arise in the presence of congestion.[43]

4.5 The need for a co-ordinated approach

The nature of the interactions between the efficient operation of the NEM and policy responses to climate change, in the context of a tightening supply/demand balance, are complex and multi-faceted. There is also significant uncertainty currently because the design issues are not yet resolved. This uncertainty in itself creates its own challenges for the efficient operation of the NEM in the short- to medium-term.

As the detailed policy design questions become resolved, we will have a clearer understanding of how precisely the market is likely to evolve—and how effectively the market design and Rules, including the CM Regime, will continue to support efficient outcomes. It is therefore timely to consider what impact climate change policies, such as ETS and MRETs, may have on the NEM and whether the current Rules and regulatory framework will continue to provide an efficient and proportionate means of promoting efficient outcomes.

It is important that the principles that have guided this Review continue to apply to any future review. Reform should be proportionate and based on sound evidence and reasoning, developed in the light of active stakeholder engagement. A future review should take into account:

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[41] Gregan and Read, "Congestion Pricing Options: Overview".

[42] The group of generators included: TRUenergy, International Power, Flinders Power, AGL and LYMMCO.

[43] See Appendix D for a more detailed discussion of these proposals.

- the recommendations made in this Review;
- the recommendations to create an NTP, reform the Regulatory Test, and introduce a framework for nationally consistent transmission planning standards; and
- other related reforms already implemented, such as the change to the Snowy region, the process for region change, the LRPP, and the transmission regulation framework.

Given the extensive range of interactions, partial assessment runs the risk of unintended consequences and less efficient outcomes. It is therefore important for further review and change to be conducted and considered in a holistic and co-ordinated manner.

A comprehensive review would consider how modifications to the energy market design and regulatory framework will ensure that the impacts of climate change policies on the NEM can be accommodated efficiently and at least cost. Such a review would need to:

- address the likely nature and extent of the impact of climate change policies on the structure, economics and performance of the NEM;
- identify any elements of the NEM regulatory framework that may require incremental or more fundamental change to accommodate the impacts of climate change policies; and
- identify and assess the feasible options for change to the energy market design and regulatory framework to facilitate the integration of climate change policies with the continued efficient operation and performance of the NEM.

Building upon the congestion management reforms already being implemented, we consider that this Final Report and its important incremental recommendations will improve the CM Regime and provide important direction on the nature and scope of the priority areas for future review and reform in the context of climate change policies.

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