Australian Energy Market Commission

Congestion Management Review

Directions Paper

12 March 2007

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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.

Contents

Abbreviations

AC	Alternating current
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AHW	Anderson, Hu and Winchester
ANTS	Annual National Transmission Statement
APR	Annual Planning Report
CBR	Constraint Based Residue
CMR	Congestion Management Review
CoAG	Council of Australian Governments
Commission	See AEMC
CPT	Cumulative Price Threshold
CRA	Charles River Associates
CRNP	Cost Reflective Network Pricing
CSC	Constraint Support Contract
CSP	Constraint Support Payment
DSM	Demand Side Management
ERIG	Energy Reform Implementation Group
ETEF	Electricity Tariff Equalisation Fund
FTR	Financial Transmission Rights
IES	Intelligent Energy Systems
IRSR	Inter-regional Settlement Residue
ISDA	International Swaps and Derivatives Association
JPB	Jurisdictional Planning Bodies
LRPP	Last Resort Planning Power

MCC	Marginal Cost of Constraints
MCE	Ministerial Council on Energy
MLF	Marginal Loss Factor
MMS	McLennan Magasnik Associates
MMS	Market Management System
MSORC	Market and System Operation Review Committee
MT-PASA	Medium term PASA
MWh	Mega watt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NEMMCO	National Electricity Market Management Company
NPV	Net Present Value
NSA	Network Service Agreement
NSCS	Network Support and Control Services
NTFP	National Transmission Flow Paths
OCC	Outage Cost of Constraints
PASA	Projected Assessment of System Adequacy
Plan	National Transmission Development Plan
PWC	PriceWaterhouseCoopers
QNI	Queensland-New South Wales interconnector
Review	See CMR
RRN	Regional Reference Node
RRP	Regional Reference Price
Rules	National Electricity Rules
SFE	Sydney Futures Exchange

SNI	South Australia – New South Wales interconnector
SOO	Statement of Opportunity
SRA	Settlement Residue Auction
SRMC	Short run marginal cost
ST-PASA	Short term PASA
TCC	Total Cost of Constraints
TNSP	Transmission Network Service Provider
ToR	Terms of Reference
TUoS	Transmission User of Service
USE	Unserved energy
VoLL	Value of Loss Load

Executive summary

In October 2005, the Ministerial Council on Energy (MCE) made a reference under the National Electricity Law (NEL) requesting the Commission to review the requirement for and scope of enhanced trading arrangements in relation to congestion management and pricing in the National Energy Market (NEM).

The Terms of Reference (ToR) for the Congestion Management Review (CMR or "the Review") require the Commission to:

- identify and develop improved arrangements for managing financial and physical trading risks associated with material network congestion – clause 3.1; and

- clearly articulate the relationship between a constraint management regime and other matters impacting on congestion, including TNSP incentive arrangements, the Last Resort Planning Power and the Regulatory Test – clause 3.2,

while having regard to Charles River Associates (CRA) previous work on constraint management and the results of the constraint support pricing/constraint support contract trial in the Snowy Region.

This Directions Paper follows the CMR Issues Paper, published in March 2006. The Commission received 29 submissions to the Issues Paper and undertook detailed analysis into the issues that had been identified in those submissions. An Industry Leaders Strategy Forum was held on 17 October 2006 to obtain views and opinions from industry leaders on a range of relevant issues.

In addition to conducting the Congestion Management Review, the Commission has been considering a number of National Electricity Rule (Rule) changes that are likely to have some impact on congestion, and thereby the likely outcomes from the Review. These Rule changes include the creation of a Last Resort Planning Power (LRPP), changes to regional boundaries in the Snowy area of the NEM, development of principles for the Regulatory Test, and the MCE proposed Rule for the criteria and process for changing region boundaries. As far as practicable, the Commission will progress the Review and these (and any other) related Rule change proposals in an integrated manner.

Given the current stage of the Commission's analysis of congestion management issues, this Directions Paper seeks to inform interested stakeholders as to the Commission's progress and intended areas of focus as it finalises the draft Review report. In particular this paper:

- further develops and explains the Commission intended approach to, and analytical framework for, the Congestion Management Review;

- outlines the Commission's view of the empirical analysis undertaken to date on the materiality of congestion in the NEM;

- highlights the key options for change to existing congestion management arrangements that are intended to be analysed further; and
- provides information on the Commission's forward work plan for better understanding the materiality of congestion, as well as in relation to each of the key options for reform.

Developing an analytical framework for congestion management

The Commission understands that transmission congestion is associated with physical and financial trading risks for participants in the NEM. The physical trading risks arise due to a 'disconnect' between bidding, pricing and settlement in a regional market design, where generators are dispatched on a nodal basis but are paid according to the regional reference price. This can give rise to perverse bidding incentives and inefficient dispatch and locational investment decisions. The financial risks of congestion arise due to the scope for regional prices to diverge and expose participants with inter-regional contract positions to basis risk. This can discourage NEM-wide trading and deter competitive conduct. In short, if the trading risks of congestion cannot be adequately managed, market outcomes may work against the promotion of the NEM Objective.

Measuring congestion and its impact

A fundamental element of the Review is to assess the materiality of congestion in the NEM. This involves understanding both the incidence of congestion, as well as its implications for economic efficiency. The Commission's commitment to good regulatory practice demands that only congestion that is material can justify a change to the NEM arrangements. This is because all policy interventions impose their own costs and should not be undertaken lightly.

The Commission has reviewed all of the available work that has been undertaken to date that measures the incidence and impact of congestion. This analysis has so far demonstrated that it is unclear whether congestion has been, is, or will be a material problem in the NEM.

Given the importance of this question to the overall Congestion Management Review, the Commission has developed a major work program to undertake further analysis on the materiality of congestion. The Commission will examine evidence of materiality closely before making any recommendations for change to the current congestion management arrangements.

Current congestion management arrangements

This Directions Paper outlines key features of the current NEM design that assist in the management of congestion and the risks associated with congestion. These features include the dispatch process, spot and transmission pricing arrangements, information requirements and transmission economic regulatory provisions. Changes are currently underway to these design features and others may follow as a result of the outworkings of the Council of Australian Governments (CoAG) Energy Reform Implementation Group (ERIG) process.

Options for managing physical and financial trading risks

There are a range of options for managing physical and financial trading risks arising from transmission congestion, as previously identified by the Commission and raised in submissions.

The Commission has identified two broad paths for addressing the physical and financial trading risks of congestion. The first is through mechanisms for enabling participants to better manage trading risk and the second is by alleviating the congestion that gives rise to those trading risks.

The physical dispatch risks of congestion can be better managed if congestion is priced more precisely. More refined pricing can attenuate the disconnect between bidding, dispatch and settlement that gives rise to dispatch risk. At the same time, more refined pricing can increase both generators' incentives to exercise transient market power and participants' exposures to basis risk. Financial basis risk, in turn, can be more easily managed if appropriate risk management instruments are available. The current inter-regional settlement residue (IRSR) regime has some notable shortcomings in this regard. Finally, participants are in a better position to manage both the physical and financial risks of congestion if they have access to information on congestion that is timely, comprehensive and accurate.

The prevailing level of congestion clearly affects the trading risk arising from congestion. Greater investment in transmission services (whether physical assets or network support and control services), where efficient, can directly reduce the level of congestion by increasing the transfer capability of the network. Similarly, investment in transmission alternatives can reduce the incidence of congestion when the system is under stress. The Commission has recently overhauled transmission regulatory arrangements to promote more timely and efficient investment and does not presently intend to revisit these changes within the CMR. Further, greater investment may not always be required to alleviate congestion. More efficient operation of transmission networks may also reduce the incidence and impact of congestion. The Commission has recently implemented changes to the Rules to enable the Australian Energy Regulator (AER) to develop stronger incentives to this effect.

Of the range of options identified, the main options that the Commission intends to examine more closely are:

- enhanced information provisions regarding network operation and congestion incidence and impacts;
- pricing for 'constrained-on' generation;
- modifications to the Inter-Regional Settlement Residues (IRSR) hedging instruments;

- constraint support pricing and constraint support contracts, as developed by CRA; and
- constraint-based residues, as outlined by Dr Darryl Biggar.

Next steps for the Congestion Management Review

The Commission has previously indicated its intention to publish a draft Review report in June 2007. However this may be revisited in light of the receipt of a number of Rule changes in relation to proposed changes to the Snowy Region boundary. Given the interrelationships between the region boundary Rule change proposals and the Congestion Management Review, it may be appropriate to align the publication of a draft Review report with the determinations for the Rule changes such that these matters can be considered by the Commission and by interested parties in an integrated manner.

As these timing questions are resolved by the Commission in the next few weeks, it will communicate its intended release period for the draft Review report.

Finally, the Commission invites submissions on the questions raised in this paper, and on the issues proposed to be analysed further as it develops its draft Congestion Management Review report. Submissions should be received **no later than 13 April 2007**.

Submission can be sent electronically to submissions@aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box H166
Australia Square NSW 1215

1 Background

1.1 Ministerial Council on Energy Terms of Reference

In October 2005, the Ministerial Council on Energy (MCE) made a notice of reference under Part 4, Division 4 of the National Electricity Law directing the Australian Energy Market Commission (AEMC or Commission) to consider the requirement for and scope of enhanced trading arrangements in relation to congestion management and pricing in the National Electricity Market (NEM).[1] This review is hereinafter referred to as the Congestion Management Review (CMR or the Review).

The MCE direction originally required the Commission to complete the CMR and publish a final report within 9 months of the receipt of the Terms of Reference (ToR). However, the Commission subsequently sought and obtained an extension to October 2007.

The Commission's interpretation of the ToR is discussed in Chapter 2, which also details the Commission's intended approach to this Review.

1.2 Progress on the CMR to date

The Commission has undertaken a number of tasks in the course of the CMR to date and has also completed or is considering a range of other issues that are directly related to the management of congestion in the NEM. These related issues include:

1. two competing Rule change proposals concerning the short-term management of negative residues around the Snowy region using a partial Constraint Support Pricing (CSP)/Constraint Support Contract (CSC) trial at Tumut;

2. two alternative Rule change proposals regarding changes to the Snowy region boundaries — one from Macquarie Generation and another from Snowy Hydro. In March 2007, the Commission received a new Rule change proposal from Macquarie Generation regarding the Snowy Region;

3. a Rule proposal from the MCE on the process and criteria for implementing boundary changes.[2] The criteria and process for regional boundary change will have clear interdependencies with the CMR;

4. Review of the economic framework for transmission regulation;[3]

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[1] *National Electricity (South Australia) Act* 1996, *National Electricity Law, Notice of Reference under Part 4, Division 4, Terms of Reference for the Australian Energy Market Commission, Congestion Management Review* (attachment A to a letter from The Hon Ian Macfarlane MP, Minister of Industry, Tourism and Resources, Chair of the Ministerial Council on Energy, to Dr John Tamblyn, Chair, Australian Energy Market Commission, 5 October 2005).

[2] *National Electricity Rules – Rule Change Request, Reform of Regional Boundaries*, letter from The Hon Ian Macfarlane MP, Minister of Industry, Tourism and Resources, Chair of the Ministerial Council on Energy, to Dr John Tamblyn, Chair, Australian Energy Market Commission.

5. the development of principles for the making of the Regulatory Test;[4] and

6. the Last Resort Planning Power (LRPP).[5]

The Commission published an Issues Paper for the CMR in March 2006.[6] The Issues Paper outlined the inter-linkages between the CMR and these related issues. Subsequently, in June 2006, the Commission published a "Statement of Approach" that set out the process the Commission intended to take in progressing the CMR and related issues.[7] A revised Statement of Approach was published in December 2006.[8]

In addition, the Commission has published draft and final Rule determinations on the Southern Generators' proposal[9] and the Snowy Hydro re-orientation proposal[10]; both of which deal with interim measures for managing congestion in the Snowy Region. In January 2007, the Commission published a draft Rule determination on the Snowy Hydro boundary change proposal.[11]

In the course of developing this Directions Paper, the Commission has considered the views of stakeholders made in submissions to the CMR Issues Paper, as well as in relation to the Rule change proposals referred to above. Appendix A provides a comprehensive summary of submissions on the CMR Issues Paper as well as supplementary submissions relating to the CMR.

As noted in the Issues Paper, the Commission has completed or is undertaking a number of work programs on matters that could indirectly affect the likely occurrence or cost of congestion in the NEM. For example, the Commission completed its review of transmission revenue and pricing regulation in the second half of 2006. The Rules that emerged from this process placed an increased emphasis on Transmission Network Service Providers (TNSP) service performance, including the availability and capability of the transmission network. In particular, the revenue "at risk" for each TNSP was increased from +/- 1% of TNSPs' regulated revenues under the previous Australian Energy Regulator (AER) regime to +/- 1 to 5% of regulated revenues under the new Rule. Improved TNSP service performance

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3 AEMC 2006, *National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, Rule Determination, 16 November 2006, Sydney; AEMC 2006, *National Electricity Amendment (Pricing of prescribed Transmission Services) Rule 2006 No. 22*, Rule Determination, 21 December 2006, Sydney.

4 AEMC 2006, *Reform of the Regulatory Test Principles*, Final Determination, 30 November 2006, Sydney.

5 AEMC 2007, *National Electricity Amendment (Transmission Last Resort Planning) Rule 2007*, Rule Determination, 8 March 2007, Sydney.

6 AEMC 2006, *Congestion Management Review, Issues Paper*, 3 March 2006, Sydney.

7 AEMC 2006, *Congestion Management Program – Statement of Approach*, June 2006, Sydney.

8 AEMC 2006, *Congestion Management Program – Statement of Approach December 2006*, 7 December 2006, Sydney.

9 AEMC, *Management of Negative Settlement Residues in the Snowy Region*, Draft Rule Determination, 6 June 2006, Sydney; AEMC 2006, *Management of negative settlement residues in the Snowy Region*, Final Rule Determination, 14 September 2006, Sydney.

10 AEMC 2006, *Management of Negative Settlement Residues by Re-orientation*, Draft Rule Determination, 14 September 2006, Sydney; AEMC 2006, *Management of Negative Settlement Residues by Re-orientation*, Final Rule Determination, 9 November 2006, Sydney.

11 AEMC 2007, *Abolition of Snowy Region*, Draft Rule Determination, 19 January 2007, Sydney.

should, other things being equal, reduce the level and cost of transmission congestion.

Another important development has been the implementation of a Rule outlining principles for a revised Regulatory Test.[12] The new principles provide the framework within which the AER makes the Regulatory Test. The principles include a requirement that all likely alternatives are taken into consideration, without regard to matters such as energy source, technology or ownership. This represents a change from the previous Regulatory Test, which only required that alternatives be genuine and practicable. The principles also require TNSPs to publish a request for alternatives when assessing a potential "large new transmission network investment". A more effective Regulatory Test should promote more efficient transmission investment, which may in turn reduce the occurrence of congestion and, potentially, the physical and financial trading risks arising from congestion.

Finally, on 8 March 2007, the Commission published its final Rule determination on the transmission last resort planning power.[13] The corresponding Rule will be made and commence operation on 15 March 2007. The LRPP allows the Commission to require a TNSP to conduct a Regulatory Test assessment for a particular transmission investment under certain circumstances. However, the power is limited to conducting the Regulatory Test and does not require a TNSP to make an investment even if it is found to maximise net benefits. To the extent the LRPP results in more timely and efficient transmission investment, the physical and financial risks of congestion may be reduced.

1.3 Policy context for the CMR

Previous publications by the Commission have highlighted the weight it places on the importance of public policy settings and the outcomes of the work being undertaken by other policy-making bodies. In the context of the CMR, the Commission has noted and considered the discussion papers produced by the Electricity Reform Implementation Group (ERIG) in late 2006.[14] ERIG is a body formed through the Council of Australian Governments (CoAG). ERIG's discussion papers have dealt with a range of matters, including transmission and energy financial markets, which are highly relevant to the CMR. In particular, the Commission notes ERIG's position in favour of the need for stronger locational signals for generation investment, notwithstanding the existence of non-price signals. ERIG also commented on the future role of the Regulatory Test and the case for a national transmission planning body as well as the shortcomings of the existing inter-regional hedging instruments in the NEM.

The Commission notes that the outworking of CoAG in response to the ERIG discussion papers could significantly impact on the appropriate methods for managing congestion in the NEM.

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12 AEMC 2006, *Reform of the Regulatory Test Principles*, Final Rule Determination.

13 AEMC 2007, *National Electricity Amendment (Transmission Last Resort Planning) Rule 2007*, Final Rule Determination.

14 The ERIG Discussion papers are available at http://www.erig.gov.au

1.4 Purpose and outline of this paper

This Directions Paper is intended to serve a number of functions.

First, the paper seeks to further develop the Commission's intended approach to, and analytical framework for, the CMR from the view outlined in the Issues Paper. In doing so, the Commission has taken account of stakeholder responses to that paper (see Appendix A for a summary of submissions). Chapter 2 has sought to clearly describe the Commission's approach to the Review. This includes its interpretation of the ToR for the Review, the evaluation criteria to be applied by the Commission, and the Commission's analytical framework for considering the relevant issues.

Second, the Directions Paper describes work that has been undertaken to date assessing the materiality of the problems associated with congestion in the NEM (Chapter 3).

Third, the Directions Paper describes the existing Rules that directly or indirectly relate to congestion management in the NEM. While it is true that virtually all parts of the Rules have some impact on congestion and the trading risks arising from congestion, the key interactions are dealt with in Chapter 4.

Fourth, the Directions Paper highlights the key options for change to congestion management arrangements in the NEM and signals the Commission's intended areas of focus for further investigation.[15] This involves a broad overview of the options (Chapter 5), as well as more specific discussions of incremental options for change (Chapter 6) and more fundamental options for change (Chapter 7). These Chapters effectively indicate the Commission's interpretation of the scope of the review. The Commission is particularly interested in the views of stakeholders on the appropriateness of these intended areas of focus. Chapter 8 addresses questions about the packaging and sequencing of the various options discussed previously.

Finally, Chapter 9 of the paper summarises the Commission's intended way forward for the CMR, highlighting the Commission's intended work programs.

1.5 Next steps in the CMR

The revised Statement of Approach published in December 2006 indicated that the Commission intended to publish a draft report on the Congestion Management Review in June 2007.

However, as noted in Chapter 1.2, the Commission has been dealing with a number of issues and Rule change proposals that are related to the CMR. In particular, the Commission has received competing boundary change proposals seeking to address physical and financial trading risks arising out of congestion in the Snowy Region of

[15] While the Commission intends to investigate a number of alternative approaches to managing congestion, whether any recommendations to implement a specific approach or approaches are made will depend on the Commission's assessment of whether congestion can be considered to be a material problem, in line with the Terms of Reference.

the NEM.[16] Given the inter-relationships between the region boundary Rule change proposals and the CMR, it may be appropriate to align the publication of a draft Review report with the determinations for the Rule changes such that these matters can be considered by the Commission and interested parties in an integrated manner.

As these timing questions are resolved by the Commission in the next few weeks, it will communicate its intended release period for the draft Review report. To assist this process, the Commission would appreciate any stakeholder responses to this Directions Paper, including timetable issues, by 13 April 2007.

[16] On 5 March 2007, the Commission received a new Rule change proposal from Macquarie Generation seeking to split the Snowy region in two. First round consultation under s.95 of the NEL on the proposal commenced on 8 March 2007. Submissions close on 30 April 2007.

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2 Commission's approach to the Review

2.1 Interpretation of the MCE Terms of Reference

The Commission's approach to the CMR has been guided by drawing directly from the MCE's Terms ToR.

The ToR for the CMR requires the Commission 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 material congestion until those issues are addressed through investment or a boundary change (clause 3.2).

In undertaking these tasks, the ToR requires the Commission to:

- take account of and articulate the relationship between a constraint management regime, constraint formulation, regional boundary change criteria and review triggers, Annual National Transmission Statement (ANTS) flowpaths, the LRPP, the Regulatory Test, and TNSP incentive arrangements (clause 3.2); as well as

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

The Commission interprets clause 3.1 of the ToR to require consideration of a broad range of options for assisting participants to manage trading risks associated with congestion in the NEM. These options could include arrangements to better *manage* congestion, thereby reducing trading risks, as well as arrangements that could reduce the *level* of congestion. The former approach takes the level of congestion as more or less given and focuses on changes that could assist participants to manage the trading risks arising from that given level of congestion. The latter approach focuses on arrangements for reducing the trading risks associate with congestion indirectly by tackling the level of congestion itself.

In this context, the Commission highlights that it has already undertaken substantial work on these latter types of measures. For example, the Commission recently completed its review of transmission revenue and pricing, which should promote more timely transmission investment and sharper incentives to maximise network availability. These issues are critically important and impact on the overall levels of congestion; however, given their earlier treatment, the Commission does not intend to consider these issues further as part of the CMR.

The Commission considers that the distinction between arrangements to better manage congestion and arrangements to reduce the level of congestion is a useful one to maintain in the CMR. Therefore, the distinction is used in describing both the existing Rules for addressing congestion as well as the potential options for change.

The Commission also notes that clause 3.2 of the ToR requires specific consideration of congestion management regimes that are designed to apply to material congestion issues for limited periods until investment or boundary change addresses the constraint. This necessarily circumscribes the range of options to be considered within the Review. For example, as discussed in Chapter 8, a shift to full nodal pricing for both generation and load would not fall within the scope of this clause and hence, the scope of the CMR more generally. However, the ToR allow for consideration of more refined pricing for generation in order to more efficiently manage congestion.

The frequent reference to "material" congestion in the ToR has been noted by the Commission. In parallel with the consideration of various options for changes to congestion management arrangements, the Commission has reviewed previous studies on the materiality of congestion in the NEM and intends to maintain a work programme in this area. All options for permanent change or for the implementation of interim regimes are likely to involve costs as well as benefits. Therefore, whether any option is justifiable against the NEM Objective (see below) depends on a comparison of the costs and benefits of the option against the status quo counterfactual – that is, the materiality of pre-existing congestion. The Commission sees no virtue in pursuing changes that increase the complexity of the NEM design without offering corresponding net benefits.

On the matter of the review of the CSP/CSC trial at Tumut, the Commission intends to commence this evaluation shortly. The evaluation will examine the broader impacts of the original trial, as required by clause 3.3 of the ToR, as well as following its modification by the Southern Generators Rule.[17] Although the Issues Paper sought comments on how the Commission should evaluate the trial, the Commission is seeking additional comments in light of the making of the Southern Generators Rule. These comments should focus on an appropriate framework for evaluating the effectiveness of the trial, the impacts and effectiveness of the trial and any other lessons that the trial may have for the wider use of CSP/CSC instruments in the future elsewhere in the NEM. In this context, the Commission notes the LATIN Group's submission, which advocated a wholesale roll-out of CSPs/CSCs, rather than a time-limited and targeted approach.[18]

2.2 Criteria for the Review

In considering the implications of congestion for participant trading risks, the ToR requires the Commission to focus on the net economic benefits to market stakeholders. This is similar to the obligation imposed on the Commission in the

[17] AEMC 2006, *National Electricity Amendment (Management of negative settlement residues in the Snowy Region) Rule 2006 No. 14*, Final Rule Determination, 14 September 2006, Sydney.

[18] *AEMC Congestion Management Issues Paper*, Submission from the LATIN Group of Generators (Loy Yang Marketing Management Co, AGL, TRUenergy, International Power. NRG Flinders), April 2006.

National Electricity Law (NEL) to pursue the NEM Objective. The NEM Objective is to:

> "Promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system."[19]

Therefore, the likely economic efficiency effect of an option or proposal on the market is an important element of applying the NEM Objective.

Economic efficiency is commonly defined as having three elements:

- productive efficiency – meaning the electricity system is 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 – meaning electricity production and consumption decisions are based on prices that reflect the opportunity cost of the available resources; and

- dynamic efficiency – meaning maximising ongoing productive and allocative efficiency over time, and is commonly linked to the promotion of efficient longer term investment decisions.

The Commission believes that promoting the conditions for competitive conduct in the NEM will often, though not always, spur improvements in all three dimensions of efficiency.

In addition, the Commission has taken the view that the NEM Objective is not solely focussed on a technical approach to the promotion of efficiency. Rather, the NEM Objective has implications for the means by which regulatory arrangements operate as well as their intended ends. This means that the Commission also seeks to promote stability and predictability of the regulatory framework. This, in turn, means that the Commission seeks to:

- minimise operational intervention in the market – intervention in the operation of competitive markets should be limited to circumstances of market failures. Further, the Commission recognises that market failure is only a necessary and not sufficient condition for regulatory intervention;

- promote changes that are likely to be robust over the longer term – other things being equal, the Rules for the dispatch and pricing of the market should be sufficiently stable and predictable to enable participants to plan and make both short- and long-term decisions; and

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[19] Section 7, National Electricity Law.

- promote transparency in the operation of the NEM – to the extent that intervention in the market is required, it should be based on, and applied according to, transparent criteria.

In addition, the Commission seeks to promote changes that are consistent with higher-level public policy settings and move the market in a direction of positive and self-reinforcing incremental improvements. These requirements are founded on the principles of good regulatory design and practice, which the Commission believes is central to its task in furthering the NEM Objective.

The NEM Objective also requires the Commission to consider the quality, security, and reliability of the national electricity system. As it progresses this review, the Commission will carefully consider the implications of potential congestion management arrangements for these important attributes of the NEM power system.

The Commission finally notes that different arrangements for managing risk arising from congestion may have distributional impacts. The Commission considers that the NEM Objective is primarily concerned with economic efficiency and good regulatory practice. These qualities will help ensure that the market arrangements will benefit consumers in the long term. Rather than seeing distributional outcomes as a distinct limb or component of the NEM Objective, the Commission has taken the view that distributional outcomes have relevance only in so far as they may negatively influence the stability and integrity of the market arrangements. Basing fundamental decisions on the operation of the market primarily on distributional criteria rather than efficiency and good regulatory practice is likely to be counter-productive to the interests of consumers in the long term.

2.3 Analytical framework for the Review

The Commission's framework begins with a definition of congestion and goes on to describe how congestion affects participants' physical and financial trading risks. This provides a basis for stakeholders to understand how the Commission intends to deal with the various options for change.

2.3.1 Meaning of congestion

As noted in the Issues Paper, transmission congestion arises when transmission limits prevent the system operator from dispatching the power system based on the least-cost combination of bids and offers made by market participants. Transmission limits, in turn, are broadly based on the thermal ratings of individual transmission elements (e.g. transformers, lines) or power system stability requirements. These limits are imposed principally in order to maintain or restore system security following the occurrence of a credible contingency event to the power system (e.g. lightening strike, loss of a transmission line, power station outage).

2.3.2 Implications of congestion in the NEM

As indicated in the ToR, congestion can give rise to physical and financial trading risks for market participants. If the market arrangements do not provide participants with adequate means of managing these risks, economic efficiency may be compromised. As the maximisation of efficiency is an important component of the NEM Objective, the Commission considers that inadequacies in the arrangements for congestion management should be addressed in this Review.

2.3.2.1 Physical trading risks of congestion

Subject to the reliability of its own plant, a participant faces no physical trading risk, also known as "dispatch risk", if, given the prevailing price at the regional reference node (RRN) in its region, it is dispatched to a level that is consistent with the quantity of its capacity that it bids or offers below the RRN price (also known as the Regional Reference Price or RRP). In other words, dispatch risk arises where a participant is not dispatched according to a comparison of its bid or offer to the prevailing local RRP.

Dispatch risk arises through the operation of the NEM Dispatch Engine (NEMDE). NEMDE is an optimisation program that has the objective of selecting generators (or loads) to produce (or consume) electricity in such a way that the total supply is equal to the total demand across the market at the lowest feasible cost, consistent with the physical limits on the transmission network. "Cost" in this context is based on the bids and offers submitted by participants. As discussed further in Chapter 3, the dispatch costs minimised by the NEMDE may not align with the minimisation of underlying economic resource costs. Chapter 4 provides a fuller description of the existing Rules concerning NEM dispatch and price-setting.

The constraint equations in NEMDE contain a representation of the underlying physical network and its limits.

In a market with no binding transmission limits, the plant that offers to produce electricity for the lowest price gets selected by the NEMDE to run first, with more expensive plants selected as cheaper plants become fully utilised. The last unit of plant dispatched to meet demand is referred to as the marginal generator (or load) and the bid or offer price of this plant sets the price at the relevant RRN. The definition of the RRP is that it represents the marginal cost (again based on bids and offers submitted) of meeting a 1MW increment of demand at the RRN. In a regional market such as the NEM, the RRP is also used to settle participants' transactions in the spot market. In a market without transmission constraints, generators can expect to be dispatched *and paid* the RRP on the quantity of output that they offer below or equal to the RRP. There is complete alignment between bidding, dispatch and settlement. In such an environment, participants face no physical trading risk.

However, when transmission limits are reached due to, say, rising demand or network outages, the NEMDE may be prevented from selecting the plant with the lowest submitted bids or offers, even though such plant is not being fully utilised. Instead, the NEMDE will be required to increase the output of some higher-cost plant and reduce the output of some lower-cost plant, in order to minimise the total costs of security constrained dispatch. In a network with transmission limits, the marginal cost of electricity will vary at different locations across the network. Put another way, in a market with transmission constraints, the local nodal "shadow" price for electricity will vary at different locations across the network.

Each transmission constraint gives rise to its own pattern of geographic variation of prices.

When some constraints bind, the resulting pattern of nodal shadow prices is not consistent with the regional pricing arrangements in the NEM. This arises when a constraint gives rise to different local nodal shadow prices within a single region. In this case, at least one generator faces a situation where it is dispatched according to the local nodal price, but is paid the (different) regional reference price for its output.

For example, a generator in a generation-rich area located on the side of a constraint that is remote from the RRN is likely to experience a local nodal shadow price that is *less than* the RRP. Such generators may not be dispatched even if their offer prices are *below* the RRP. Such generators are commonly referred to as being "constrained-off".

Conversely, a generator is located in a load-rich area on the far side of a constraint, remote from the RRN, is likely to experience a local nodal shadow price that is *greater than* the RRP. Such generators may be dispatched even if their offer prices are *well above* the RRP. Such generators are commonly referred to as being "constrained-on".

This situation is particularly likely to arise in the presence of network loops. Where network loops exist, a transmission constraint on just one location on the loop will give rise to local shadow prices for electricity that vary at every location around the loop. Depending on the location of the RRN relative to the loop, some generators on the loop may be constrained-on while others are constrained-off.

The NEMDE is designed so as to yield economically efficient outcomes provided all generators (and loads) submit offers (or bids) that reflect their underlying resources costs. For most participants in the market, competition ensures that they have an incentive to offer their output at a price that broadly reflects their underlying resource costs (at least at the margin). However, in the case of generators that are constrained-on or –off, they may find that if they offer their output at a price at or near to their resource cost they are not dispatched to their desired level.

As a result, in the current market design, participants who may be potentially constrained-on or -off may seek to manage their dispatch risks by altering their bids or offers away from their underlying resource costs. For example, a generator that is dispatched even though its offer price is more than the price at its RRN (constrained-on) may choose to bid at the highest permissible price ($10,000/MWh), or bid its capacity unavailable, in order to avoid being dispatched. Alternatively, a generator that is not dispatched even though its offer price is less than the price at the RRN (constrained-off) may have incentives to bid at the lowest permissible price (-$1,000/MWh), or inflexible, in order to ensure it is dispatched.

Both of these behaviours can harm the economic efficiency of dispatch because they may lead to the dispatch of plant with higher resource costs than would be the case if the distorted bids did not occur. For example, consider a generator with a resource cost of $30/MWh that avoids being constrained-on by offering its capacity at $10,000/MWh. NEMDE may then need to dispatch a more costly generator (say, with a resource cost of $50/MWh) in order to meet demand at the RRN. Similarly, a generator with a resource cost of $100/MWh may avoid being constrained-off by offering to produce at -$1,000/MWh. This behaviour may lead to the displacement of a generator whose resource costs are $30/MWh.

In the longer term, dispatch risk may have additional detrimental impacts. To the extent it leads to an increase in the economic cost of dispatch, this may also cause an increase in wholesale spot prices over time if not immediately. Higher spot prices may, in turn, flow through to higher end-user prices. This may lead to a reduction in the consumption of electricity compared to what would otherwise be the case. Economic welfare is the sum of consumer and producer surplus,[20] so an increase in prices caused by less efficient dispatch could reduce economic welfare. As noted by the Commission in its final decision on the Southern Generators' proposal[21] and its draft decision on the Snowy Hydro Abolition of Snowy Region proposal[22], there may be lags and rigidities in lower spot prices being reflected in lower retail prices actually paid by consumers.

Dispatch risk may also encourage new generators to locate in inappropriate areas. For example, a generator may have incentives to locate in an area that experiences congestion because of its ability to manage the risks of being constrained-off by offering its plant at –$1,000/MWh. This behaviour may not completely eliminate dispatch risk, but it could overcome some of the risk. Similarly, a new generator may be deterred from locating in an area where it could relieve congestion because it risks being dispatched even where its resource costs and offer price is greater than the prevailing price at the RRN (i.e. it is constrained-on). These dynamic inefficiencies could also harm the promotion of the NEM Objective.

The source of dispatch risk and the incentives to manage dispatch risks by distorting bids and offers is the disconnect between bidding, dispatch and settlement that can arise in a regional market design. If generators were both dispatched and settled on the basis of the same price, their dispatch risk would be reduced and their incentives to distort their bids in this way would diminish. Therefore, one way to analyse dispatch risk is by characterising it as a result of the *mis-pricing* that occurs in a regional market design.

At the same time, addressing mis-pricing by increasing the granularity of pricing for settlement may have detrimental effects on both:

- participants' financial trading risks; and
- generators' incentives to exercise transient market power.

The first issue is discussed in more detail in the next sub-Chapter.

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[20] Consumer surplus is equal to the difference between what consumers are willing to pay for electricity and the price they are required to pay. Producer surplus is equal to the difference between the price generators receive and their resource costs of supply.

[21] AEMC 2006, *Management of negative settlement residues in the Snowy Region*, Final Rule Determination, 14 September 2006, Sydney.

[22] AEMC 2007, *Abolition of Snowy Region*, Draft Rule Determination, 19 January 2007, Sydney.

In relation to the second issue, it is worth noting that a generator that is constrained-on or –off may not have much impact on the RRP.[23] Although that generator may not be dispatched when it is efficient to do so (or vice versa), such a generator tends to be a *price-taker*. However, an increase in the granularity of pricing might allow such a generator to receive a price closer to its local nodal shadow price. This might give the generator the ability to reduce its output in order to increase the price it receives on its remaining output. To the extent this occurs, increasing the granularity of pricing may produce less efficient dispatch and higher spot prices.

At the same time, to the extent that dominant generators have the incentives and ability to exercise transient market power in a regional market, their behaviour may affect a larger volume of electricity and customers—and be masked by the regional pricing structure—than would be the case in a more refined market pricing structure.[24]

Whether, on balance, the problem of mis-pricing in the NEM warrants a change to the market arrangements is something that the Commission is actively exploring as part of the CMR (see Chapter 3).

It should be noted that dispatch risk affects participants slightly differently depending on whether and to what extent they have entered into financial hedging contracts. Where a participant, say a generator, is uncontracted, dispatch risk can result in foregone revenue equal to the product of the RRP and the quantity of its capacity that it bids or offers below the RRP. This foregone revenue represents a real *economic* loss to the generator, but it does not involve a cash outlay by the generator.

On the other hand, where a generator is financially hedged, such as through a two-way swap contract, the generator pays or receives "difference payments" on the contract quantity depending on whether the RRN price is above or below the contract strike price, respectively. The end result of such payments is that the generator effectively receives the contract strike price on the contract quantity, *so long as it is dispatched and receives the RRP on that quantity*. This means that if a generator is hedged and is not dispatched, it may need to make cash difference payments to the counterparty that are not funded by the generator's revenues in the spot market. Such "unfunded difference payments" represent an *accounting* as well as an economic loss to the generator. For this reason, generators are particularly sensitive to dispatch risk when they are highly contracted. For the same reason, generators may be concerned about entering into a high level of forward contracts when they face dispatch risk.

2.3.2.2 Financial trading risks of congestion

Another form of trading risk arising from congestion relates to the risk of divergence between the price that a participant pays or receives in the spot market and the price

[23] See Appendix 4 of AEMC 2006, *Congestion Management Review, Issues Paper*, 3 March 2006, Sydney.

[24] Harvey, S.M. and Hogan, W.W. 2000, "Nodal and Zonal Congestion Management and the Exercise of Market Power", Harvard Electricity Policy Group, Cambridge, Mass., 10 January 2000. http://ksghome.harvard.edu/~whogan/zonal_jan10.pdf

at which its financial contracts are settled. This effect is commonly referred to as financial (or basis) risk.

In a regional market such as the NEM, and ignoring transmission losses, divergence between the price a participant pays or receives in the spot market and the price at which its financial contracts are settled occurs when:

- participants have entered into financial contracts with participants located in another region(s); and
- transmission limits that restrict flows on interconnectors between those regions bind, causing the relevant RRPs to diverge.

For example, a generator located in the Victorian region may have entered into a swap contract with a retailer in NSW, referenced to the NSW RRP. Because congestion can lead to the NSW RRP diverging from the Victorian RRP (at which the generator is settled in the spot market), the generator faces basis risk. If the contract had been referenced to the Victorian RRP, the retailer would be the party facing basis risk.

For the sake of clarity, it should be noted that in a market with one settlement price (e.g. a single-region market), basis risk does not arise (although dispatch risk of the kind described above may arise). Alternatively, in a market where each node is individually priced and settled, basis risk affects each inter-nodal financial trade. This means that a greater number of pricing points – to reduce dispatch risk by addressing the mis-pricing problem – could increase the basis risk participants face in the absence of an effective means of managing such risk. This suggests that attempts to address the mis-pricing problem through a greater number of pricing points also need to consider options for better managing the resulting basis risk. Because basis risk is only a concern to the extent that adequate hedging instruments are not accessible, one way to describe the implications of basis risk is that it gives rise to a *hedging problem*.

Participants currently seek to manage basis risk in the NEM in several ways. They may seek a form of financial insurance for price divergences, by paying other participants or agents a premium to hedge the exposure. Participants could also hedge against basis risk through physical or financial "capacity swaps" (agreements in relation to the revenues or operation of plant) with participants located in areas where contract trades are referenced. Participants could also physically hedge by acquiring plant or operations in those locations directly.

Another means of hedging basis risk is with the aid of instruments known as inter-regional settlement residue (IRSR) units, which are a form of Financial Transmission Right (FTR). The IRSR units associated with a particular "directional interconnector" provide the holder with a share of the positive stream of payments or "residues" equal to the price difference between the two regions joined by the interconnector (in the direction of the directional interconnector) multiplied by the flow on the interconnector (when the flow is in the direction of the directional interconnector). Each IRSR unit refers to a notional 1 MW of the notional physical flow limit of the corresponding directional interconnector. If the notional flow limit on an interconnector is 1000 MW, the holder of 10 MW of IRSR units receives a flow of payments equal to one per cent of the residues described above. IRSR units are presently auctioned by NEMMCO in quarterly tranches up to one year in advance. Chapter 4 provides a fuller description of the Rules concerning IRSR units.[25]

IRSR units provide the purchasers with a reliable or "firm" hedge against inter-regional price differences, so long as the price differences between the two regions joined by the interconnector are negligible unless the flow on the relevant interconnector is at the notional physical flow limit of the interconnector. However, price differences may arise between regions when the flow on the interconnector is much less than its notional physical limit due to:[26]

- transmission constraints that give rise to pricing patterns that are not aligned with the pricing regions in the NEM, as noted in the description of the mis-pricing problem above. In this case, price differences can arise between regions even though the flows on the interconnectors between those regions are well below their physical limit (and indeed, the flow may even be in the reverse direction – that is, from high-priced regions to low-priced regions (referred to as "counter-price flows");

- loops between the administrative pricing regions. As noted earlier, when a transmission constraint arises on a loop, all the locations on that loop receive a different price, regardless of the flow patterns on that loop. If there is a loop between administrative pricing regions, a constraint anywhere on that loop will give rise to price differences between neighbouring regions, even though the flows on the interconnectors between those neighbouring regions are well below their physical limit (and indeed, in certain circumstances flow between such regions must be counter-price); and

- transmission outages or deratings, which directly reduce the physical interconnector flow limits.

If any of these outcomes occur, the IRSRs accruing in respect of a (1MW) unit will not be a "firm" hedge for an equivalent 1 MW inter-regional contract exposure.

In addition, because it is often difficult for a generator to predict how other generators that influence the value of residues will bid and produce at any given time, IRSRs do not provide firm inter-regional hedges in many situations.

The creation of a more effective means of managing basis risk than is currently available in the NEM has the potential to promote economic efficiency. It can do this directly, by promoting inter-regional contract trading and reducing entry barriers for new retailers and generators. Improved basis risk management instruments can also help improve economic efficiency indirectly, by enabling more accurate locational pricing of congestion to be used to overcome some of the problems created by the

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[25] NEMMCO, Settlement Residue Auction Information Memorandum, 3 July 2006, www.nemmco.com.au.

[26] See also CMR Issues Paper Appendix 4; Biggar, D., *Congestion Management Issues, A Response to the AEMC*, 12 April 2006 (part of AER submission, 13 April 2006), paras 43-49 and Appendix.

mis-pricing of generation that can occur in a regionally settled market (discussed above).

Options for improving the management of basis risk are discussed in later Chapters.

Ultimately, if the available basis risk management options are inadequate, participants could respond by simply choosing not to contract across regional boundaries, or more broadly, across locations that are effectively settled at different prices. This could have a range of negative implications for the promotion of the NEM Objective. For example, competition for financial derivative products across the NEM could be reduced. Retailers tend to rely heavily on such products to hedge their spot market exposures and typically have highly inelastic demand for them, so less competitive contract offerings could increase wholesale contract premiums. This could eventually flow through to higher retail prices, particularly in net importing regions. Higher retail prices could, in turn, lead to lower consumption by loads compared to a situation in which basis risk was lower.

In the longer term, high basis risk may result in less retailer entry, less retail competition and again, higher retail prices. At the same time, contract prices could be depressed in generation-rich (net exporting) regions, possibly leading some generators to go unhedged. These factors may also discourage generators from locating in areas where fuel costs are low, simply to avoid the risk of price separation. In the long run, the distortion in the prices or availability of contracts could have long term implications for generator location and investment decisions, and therefore, for the long-term dynamic efficiency of the market.

Consequently, to the extent congestion is associated with increased basis risk, and this risk cannot be managed through hedging instruments or other mechanisms, economic welfare may be less than it would be otherwise.

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3 Measuring congestion and its impact

Regional (or zonal) market designs, like the NEM, are based on the premise that most of the gains a market can deliver in the economic efficiency of dispatch do not require the complexity of locational marginal pricing at all points of the network (i.e. nodal pricing). Under full nodal pricing, all the costs of congestion are captured in the locational prices. Instead, it is argued, a "simpler" regional pricing mechanism involves only a few administrative pricing points, delivers the bulk of the economic efficiencies, and enables liquid financial contract trading to take place at a small number of reference pricing hubs.

Zonal markets aim to price economically "significant" congestion, but allow the remaining congestion to either be: a) managed efficiently in other ways that largely preserve zonal pricing for most spot market transactions; or b) managed with a small, justifiable, and acceptable loss of efficiency.

The Terms of Reference requires the Commission to:

> "Identify and develop improved arrangements for managing financial and physical trading risk associated with *material* network congestion." [emphasis added]

Therefore, an assessment of the significance and persistence of congestion is required prior to determining what, if any, changes should be made to the market arrangements.

Importantly, whether congestion is "material" or detrimental to efficiency requires a consideration of the costs and benefits associated with alleviating congestion. The Commission intends to use its assessment of the materiality of congestion in the NEM to inform its recommendations on options as part of a wider management regime for congestion.

This Chapter considers how congestion can be measured and reviews available quantitative data, in order to assess the materiality of congestion within the NEM.

The Commission intends to focus future work in this area on:

- the quantification of congestion within the NEM
- understanding the causes of mis-pricing and its extent; and
- the development of recommendations for the provision of mis-pricing information on a more regular basis.

3.1 Dispatch Inefficiency

As noted in Chapter 2, transmission congestion can lead to an increase in the costs of dispatch. The AER has undertaken some analysis of historical dispatch costs in the NEM.

The AER has published a series of historical indicators of the dispatch costs of congestion for the financial years 2003/04 to 2005/06.[27] These indicators compared actual dispatch costs (based on participants' bids and offers) to dispatch costs in otherwise identical circumstances where no congestion occurred. The indicators covered both the total benefit and marginal benefit of reduced generation dispatch costs when transmission constraints are removed from the NEMDE. The AER also published an indicator of the total costs of constraints resulting from transmission outages.

Table 3.1 summarises the AER indicators and shows that dispatch costs have been increasing over the three year period and that an increasingly significant proportion of the costs is related to transmission outages. The AER has indicated that the majority of the Total Cost of Constraints (TCC) occurs on a few days of the year. For 2005/06, 66 per cent of the TCC occurred on just 10 days. For 2004/05, 70 per cent of the TCC was accumulated on just 7 days. For 2003/04, 60 per cent occurred on just 9 days of the year.[28]

Table 3.1: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

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

Data source: AER Indicators of the market impact of transmission congestion, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, and Report for 2005/06, February 2007.

The AER's indicator of the marginal cost of constraints (MCC) identifies the individual constraints that have significantly affected market outcomes.[29] The AER reported that the number of network constraints significantly affecting interconnector flows has increased from 5 in 2003/04 to 32 in 2005/06, while the number of constraints that affected market outcomes within regions on the mainland has also increased from 5 to 9 over the previous three years.

Converting the AER's measures into indices, with a base year of 2003/04, reveals a near doubling of the TCC and a tripling of the Outage Cost of Constraints (OCC) in the three year period to 2005/06 (see Table 3.1).

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[27] Australian Energy Regulator, *Indicators of the market impact of transmission congestion*, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, and Report for 2005/06, February 2007.

[28] Australian Energy Regulator, *Indicators of the market impact of transmission congestion*, Report for 2003/04, 9 June 2006; Report for 2004/05, 10 October 2006, and Report for 2005/06, February 2007.

[29] MCC data is only published for inter-regional constraints. For intra-regional constraints, only data on the amount of time which the constraint bound is reported. The MCC identifies particular elements of the transmission network that have binding limits that cause generation to be dispatched out of merit order.

A number of market participants[30] have referred to the AER indicators as evidence that congestion is not material in the NEM, except in the Snowy Region. They contend that compared to annual wholesale market sales of $6bn in the NEM, costs of congestion in the order of $36 to $66 million per annum are immaterial. The Commission acknowledges these views and notes that the AER indicators do not provide a comprehensive measure of the cost or materiality of congestion. The AER indicators do not cover all the impacts of congestion and there are important limitations on the assumptions and methodology that should be recognised when interpreting the results. [31]

First, the AER measures relate to the effect of binding constraints on the costs of dispatch as calculated by the NEMDE. These costs of dispatch may diverge from the economic resource cost of dispatch where the industry *offer* curve (i.e. generator offers) is different to the industry *cost* curve (i.e. generator resource costs). This may occur due to generators exercising transient market power (bidding above resource costs) or distorting their bids in response to mis-pricing (as discussed in Chapter 2). While it is strictly ambiguous whether these factors, in combination, would lead to the AER measures over-stating *or* under-stating the economic dispatch costs of congestion, the Commission is concerned that the former result may be more likely.

As part of its work program on the materiality of congestion, the Commission intends to investigate specific events where the recorded TCC figures are relatively large to get a better understanding of the impact of congestion on economic resource costs. For example, on 2 February 2006, the AER calculated a TCC of $12.7 million, which was a significant proportion of the TCC for the 2005/6 year of $66 million.[32] The AER put forward that the high TCC on 2 February arose at times of high demand and very high (but sub-VoLL (i.e. sub $10,000/MWh)) prices in NSW and Queensland. Whether the figure of $12.7 million was principally due to the exercise of transient market power in tight market conditions or whether it was due to the dispatch of extremely high (resource)-cost plant (or demand-side response) is the type of question the Commission will seek to address in its work program.

Second, the AER indicators are based on observed generation bids and assume that bids would be unchanged if constraints were removed. However, as explained above, both actual and potential congestion can affect generators' bidding incentives and lead them to bid at a price different from their costs. Although the AER tries to remove any distortions to bidding behaviour by replacing the bids of constrained on generators with a $300/MWh bid, bidding behaviour could nevertheless change if constraints were removed. Furthermore, the AER measures ignore the effects of strategic bidding to prevent or stop constraints binding. If generators bid

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30 Macquarie Generation submission, 17 April 2006, p.1; Newcastle Group submission (endorsed by AGL, Delta Electricity, Intergen, Loy Yang Marketing Management Company and Macquarie Generation), 17 April 2006 (submitted by Macquarie Generation) p.5; CS Energy submission, 13 April 2006, p.2.

31 Such assumptions include ignoring: (1) any ramp rate constraints for the calculation of non-network constraint dispatch; (2) any impact of network constraints on the costs of NEMMCO purchasing frequency control ancillary services; (3) the cost of any load shedding caused by congestion; and (4) the dispatch costs of generators subject to network support agreements.

32 Australian Energy Regulator, *Indicators of the market impact of transmission congestion*, Report for 2005/06, February 2007, p.9.

strategically to stop a constraint from binding, the impact of that potential congestion on efficiency would not be measured. On the other hand, if generators bid strategically to cause a constraint to bind, that constraint would appear more significant than otherwise in the TCC measure.

Given the limitations in the AER's indicators, the Commission considers that these indicators could be used to observe trends rather than provide a definitive and conclusive source of information about the cost of constraints. The AER indicators may also provide some indication of which constraints have the largest impact on the market and when they occur.

3.2 Extent of mis-pricing in the NEM

The Commission has sought to develop a more comprehensive measure of the impact of congestion in the NEM to help determine whether congestion has historically been a material problem. Dr Darryl Biggar was asked by the Commission to develop a measure of the significance of intra-regional congestion.[33]

Biggar sought to measure the materiality of congestion within regions by calculating the frequency, duration and magnitude of deviations between the theoretically "correct" locational price (or nodal shadow price) at each connection point and the RRP. The correct location price for each connection point is calculated using data from the NEM dispatch engine. It is equal to the RRP less – for every binding constraint equation – the constraint marginal value times the coefficient for the connection point in that constraint equation. This method is similar to the AER's calculation of the MCC.

Biggar investigated the extent of mis-pricing over a three year period from 2003/04 to 2005/06 and found that:

- the incidence of mis-pricing has been steadily increasing:
  - in 2003/04, there were 129 mis-priced generator connection points out of 282, each mis-priced for an average of 44 hours;
  - in 2004/05, there were 148 mis-priced connection points, each mis-priced on average for 112 hours; and
  - in 2005/06, there were 169 mis-priced connection points, each mis-priced on average for 169 hours. Notably, one source of the 2004 increase was the inclusion of Tasmania into the NEM;[34]

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[33] Biggar, D., *How significant is the mis-pricing impact of intra-regional congestion in the NEM?*, 25 October 2006 (available on the AEMC website).

[34] In a submission to the Commission, Powerlink stated that constraints associated with the implementation of Network Support Agreements should be excluded from the analysis since network support is an efficient response to network congestion under the Regulatory Test. Powerlink noted that if the constraints associated with NSA within the Queensland Region are excluded, then the incidence of "mis-pricing" reduces from 300 hours to 160 hours for 2005/05 year. Powerlink, Submission to AEMC, Congestion Management Review, 6 November 2006.

- around 95 connection points in the NEM have been mis-priced for more than 100 hours per annum on average over the last three years; and
- generator mis-pricing is unlikely to be eliminated through a small number of region boundary changes. For example, a move to 17 ANTS zones would reduce the frequency and duration of mis-pricing slightly in Queensland and South Australia, but would have virtually no impact on mis-pricing in NSW and Tasmania. If creating new regions were the only mechanism for managing intra-regional congestion, the number of pricing regions in the NEM would need to be much larger, possibly around 70, to effectively eliminate mis-pricing.

One issue that the Commission will investigate through its intended work program is whether the observed increase in mis-pricing presented by Biggar was in any way related to the rollout of fully optimised constraints by NEMMCO over the last two years. To the extent that coefficients in constraint equations may have been scaled up as part of the reformulation process, and this up-scaling led to more terms being above a certain threshold and being included in constraint equations, this may have contributed to apparent increases in the duration of mis-pricing. The Commission will seek to get a better understanding of this issue in the coming weeks and months.

An important point to note about the Biggar analysis is that it does not seek to assess how generators may have bid if they had faced the correct locational price. Therefore, it does not attempt to measure the full effect of congestion on the economic efficiency of dispatch.

The Commission subsequently made a request to NEMMCO to review the results in the Biggar paper. NEMMCO agreed to extend the analysis to cover a larger study period (from 2001/02 to 2005/06) and perform some analysis to identify the causes behind any trends in mis-pricing. NEMMCO's preliminary report will be released onto the Commission website with this Direction Paper.

NEMMCO's preliminary study confirmed Dr. Bigger's findings that there is an increasing trend in mis-pricing towards 2003/04 onwards for the NSW, QLD and SA regions and the Victorian region showed decreasing trend. However the study also showed that over the analysis period from 2001/02 to 2005/06, the number of connection points being mis-priced was fairly steady. Across all regions, the NEM-wide number of mis-priced connection points remained within a band of 120-140. Regarding the average annual duration of mis-pricing at each of those connection points, there was a big fall from about 160 in 2001/02 to 40 in 2002/03. This was followed by a gradual increase to just over 60 in 2004/05 to about 110 in 2005/06. The average duration of mis-pricing was highest in NSW and Queensland and lowest in Victoria and Tasmania.

NEMMCO's study lists range of possible reasons behind the mis-pricing trends and notes that most of the reasons are specific to the region and the situation at the time. NEMMCO also commented that the progressive conversion of option 8 constraints to a fully optimised formulation would have also contributed to the increase in incidence of mis-pricing.

The work undertaken by NEMMCO raises the issue of whether the incidence of mis-pricing observed by Biggar is substantially driven by outage events. This may be significant as the Commission believes the appropriate policy response to congestion during system normal conditions and those during periods of outage events may well be different.

The Commission also notes that the NEMMCO analysis to date has only focussed on historical events and considered the number of connection points mis-priced and average duration. As with the Biggar analysis, it is a backward-looking study. Further, as again is the case with the Biggar analysis, the NEMMCO analysis does not calculate the economic dispatch cost of mis-pricing.

3.3 Congestion Trading Risks

Chapter 2 explained how congestion can create financial risks for participants who have entered into inter-regional contracts. An important dimension of measuring the impact of congestion involves assessing the effectiveness and efficiency of mechanisms available to facilitate financial risk management.

The main financial instrument for hedging against the inter-regional pricing risk caused by congestion in the NEM is IRSR units, which provide a right to a share of any positive inter-regional settlement residues that accumulate when electricity flows from one region to another. As noted in Chapter 2 and discussed below, IRSR units do not provide a perfect hedge against regional price differences in certain instances.

One way of considering the extent to which IRSR units provide a *financially* firm inter-regional hedging instrument is by observing the volume of interconnector flows at times of price differentials between the relevant regions. For the units to be a fully financially firm instrument, inter-regional price divergences must only occur when interconnector flows are at their expected limit (and there is no risk of the interconnector limit being de-rated). If price differentials open up at other times, the resulting settlement residues will not be sufficient to hedge an equivalent inter-regional contract exposure.[35] Indeed, analysis undertaken for the ERIG Energy Financial Markets Discussion Paper shows that this is often the case.[36] For example, for southward flows on QNI during 2005/06, inter-regional price separation occurred almost as often when QNI flows were 600 MW as when flows were near their limit of 1,200 MW. ERIG made similar observations about the Snowy to Victoria interconnector and the Victoria to South Australia interconnector (which was the firmest of the three in that year).

Another approach to assessing the effectiveness of the existing IRSR instruments is by comparing the difference between Settlement Residue Auction (SRA) proceeds, which is the amount that participants are prepared to pay for IRSR units, and the outturn IRSRs themselves. A large difference between the two could arise for a number of reasons. For example, participants may not be willing to pay a certain

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[35] See Biggar, D., *Congestion Management Issues, A Response to the AEMC*, 12 April 2006 (part of AER submission, 13 April 2006), paras 43-49 and Appendix.

[36] Energy Reform Implementation Group, *Discussion Papers*, pp.173-175.

sum of money in exchange for an uncertain future return (i.e. they may be risk averse).

Another explanation is lack of competition in the SRA process. However, to the extent that participants only seek to acquire IRSR units to hedge inter-regional financial contracts (i.e. not for the purposes of speculation), a large positive difference between the actual value and expected value of the residues could also be an indicator that participants' willingness to pay for IRSR units includes a significant discount for their potential lack of firmness. A negative difference would indicate a substantial risk premium was paid to secure the IRSR units, with their actual value being less than that expected.

Table 3.2: Difference between SRA proceeds and settlement residues by interconnector ($). (Settlement residues minus auction proceeds)

	NSW/Snowy	QLD/NSW	Snowy/VIC	SA/VIC	Total
1999/00	3,000,300	0	-685,600	17,046,370	**19,361,070**
2000/01	8,109,500	2,833,200	35,012,500	-5,116,700	**40,838,500**
2001/02	61,897,311	9,564,687	-53,020,848	-7,019,456	**11,421,694**
2002/03	41,591,556	18,252,365	-6,847,458	5,065,270	**58,061,733**
2003/04	5,928,985	8,439,598	25,922,518	19,367,102	**59,658,204**
2004/05	88,525,543	49,854,815	-10,562,140	-2,663,412	**125,154,805**
2005/06	53,566,285	37,532,803	4,150,744	8,036,509	**103,286,341**

Note: Figures combines Auction differences for both flow directions for each interconnector.

Data source: NEMMCO

Table 3.2 shows that a significant excess of settlement residues over the auction proceeds occurs and that the total excess has generally been increasing since 1999/2000. However, the table also shows that the extent of the excess varies considerably across the four main interconnectors in the market. Notably, the average size of the excess on the Victoria-South Australia interconnector (the "firmest" interconnector, at least for 2005/06 based on ERIG's analysis) appears to be smaller than the Queensland-NSW interconnector (which ERIG found to be less firm). This is consistent with the hypothesis that varying levels of firmness, rather than a more generalised tendency towards risk aversion, may be the key driver for the discounts applying to certain SRA bids and proceeds.

A third approach for assessing the effectiveness of IRSRs is to use a survey of market participants. Notwithstanding the Commission's recognition of the pitfalls of excessive reliance on surveys in such a context, it notes the findings of the survey recently commissioned by the National Generators Forum and Energy Retailers Association of Australia. This survey was undertaken by PriceWaterhouseCoopers (PWC) and was conducted with heads of trading in each of the main trading market participants. The survey assessed whether financial markets are effectively helping participants to manage their risks in the NEM.[37]

The general consensus highlighted in the PWC survey is that the level of liquidity in financial markets is adequate to support the management of NEM risks, although most respondents would prefer greater liquidity in derivatives trading. Agreement was also expressed on the point that removing regulatory uncertainty and removing market distortions (e.g. retail price capping and NSW's Electricity Tariff Equalisation Fund (ETEF)) would improve liquidity.

Fifteen out of the seventeen respondents stated that they are comfortable that they can adequately manage inter-regional basis risk, either through the acquisition of IRSR units or financial swaps. Views were mixed on the effectiveness of IRSR units as a risk management tool, with some respondents happy to internalise the lack of firmness, while others perceived that a "firming up" of IRSR units would increase cross-border trade. The general view from respondents was that market liquidity would increase and that the electricity market was maturing. There was also a general view that an increase in the number of nodes would probably reduce liquidity and could lead to too much complexity for participants to manage.

The Commission also notes the results of another survey of market participants into the contracting process and practice of risk management in the NEM. The survey was conducted by Anderson, Hu and Winchester (AHW) from the University of NSW and formed part of their research paper entitled "Forward Contracts in Electricity Markets: the Australian Experience".[38] AHW interviewed 26 markets participants during late 2005, and like the PWC survey, the interviewees were in the most cases the general manager of the trading team for the companies.

This AHW survey has some different findings to the PWC survey. The AHW survey found that the auctioning of IRSR units does not operate effectively to encourage inter-regional contract trading. Almost all the participants said that they tried to arrange contracts between counterparties in the same region, so as not to be exposed to inter-regional trading (basis) risks. When such basis risk was taken on, the participants reported that they often hedged them through an inter-regional product (a swap based on the difference between the RRPs), rather than IRSR units and many participants stated that they were not actively involved in the SRA. The paper concluded that it seemed that a significant part of the trade in IRSR units was speculative rather than carried out for hedging purposes.

3.4 Sub-optimal Investment Decisions

Network and generation investments have the potential to either alleviate or exacerbate congestion. As discussed in Chapter 2, unpriced congestion may lead to poor locational decisions, which serve to exacerbate congestion. Approaches

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[37] PriceWaterhouseCoopers, New Perspectives on Liquidity in the Financial Contracts Electricity Market, Survey, November 2006.

[38] This paper was part of NEMMCO's 4 August 2006 submission to ERIG and is available from the ERIG website (www.erig.gov.au).

assessing recent investment decisions in the NEM have tended to investigate whether the current market rules and framework create incentives for investment decisions that are consistent with the maximisation of economic efficiency. A number of participants have submitted reports to the Commission based on this approach.

Macquarie Generation[39] commissioned a report by McLennan Magasnik Associates (MMA) to determine whether TNSPs are adequately managing intra-regional congestion in the NEM. MMA reviewed the Annual Planning Reports (APRs) for each NEM region and other relevant documents to assess how TNSPs managed major intra-regional constraints. The reporting and action on each constraint was tracked from 2001 to 2006. MMA's conclusions were:

- transmission system reliability indicators show that system reliability has been improving and the regional networks are performing well;

- these indicators, as well as the development of network projects described in the APRs, show that intra-regional constraints in each region have been managed appropriately; and

- TNSPs are anticipating emerging constraints and responding appropriately such that no material congestion emerges.

MMA's analysis focussed on whether TNSPs are responding adequately to the reliability requirements of their respective networks. MMA's report noted that it did not specifically consider augmentations undertaken for market benefit reasons and commented that it would be incumbent on market participants who perceive that they are being disadvantaged by network conditions to seek the support of TNSPs to identify cost effective options. Augmentations for market benefit reasons is an important mechanism to deal with congestion and the Commission notes that participants would only initiate change from a TNSP if they had adequate information and understanding.

The Commission also acknowledges the points made by the LATIN Group in response to the MMA report.[40] The LATIN Group disagreed with the conclusions made in the MMA report, stating that intra-regional congestion is not immaterial on the basis that it is not adequate to assess materiality solely on the basis of historical measurements of congestion or the investment activities of TNSPs. This is because new generation investments would cause more congestion in the future. The LATIN Group also noted that TNSPs are not permitted, under the regulatory arrangements, to recover the costs of augmenting the network simply for the purposes of relieving network constraints. Regulated investment must be justified for reliability or market benefits reasons under the Regulatory Test. The implication on these conditions is that "material" congestion could arise and persist for extended periods of time.

[39] Macquarie Generation Supplementary Submission to Congestion Management Review, 25 September 2006.

[40] LATIN Group, Supplementary Submission, Congestion Management Review, 17 November 2007.

The work by MMA provides insight into whether TNSPs are responding to the reliability needs of their respective networks. This is one dimension of the wider issue of whether transmission and generation investment decisions together minimise the impact of congestion on the economic efficiency of the market. The Commission is investigating this issue further.

In its supplementary submission dated 22 December 2006, the LATIN Group presented a report entitled "Modelling of Transmission Pricing and Congestion Management Regime", prepared by Intelligent Energy Systems (IES).[41] This report estimated the extent of dynamic inefficiencies caused by transmission investment and generation locational investment under the current regime, using a case study of a single region in the NEM, Queensland. It went on to compare the current regime of a single a RRP for Queensland to two scenarios of: (a) introducing eleven nodal prices for Queensland via a full regime of constraint support pricing (see Chapter 7 for a discussion of CSPs) and (b) including a congestion levy on new generators in additional to the nodal pricing regime introduced under scenario (a).[42] Modelling results of IES's report relating to the comparison of total savings of introducing locational pricing and congestion levies are included in Table 3.3.

Table 3.3: Results from IES modelling on the comparison of total savings of introducing locational pricing and congestion levies, Queensland region ($m NPV for 2006/07 to 2020/21)

Scenario	Dispatch Cost Savings	Generation Capital Cost Saving	Transmission Investment Savings	Total Cost Savings
Locational pricing	-58.06	130.8	121.91	194.5
Locational pricing with congestion levy	-365.52	464.06	123.98	222.5

Data source: IES

The study estimated an overall benefit $194.65m (net present value (NPV)) in efficiency savings from introducing nodal pricing to the Queensland region of the NEM through a comprehensive CSP regime. Although the results for scenario (a) show an increase in the overall dispatch costs caused by increased generation from relatively more expansive plant, this is more than offset by significant reductions in transmission and generation capital costs. IES found that the nodal pricing option for Queensland would result in generation replacing transmission upgrades. IES estimates that benefit, based on only the changes to pricing in Queensland, would increase to $222m (NPV) with the addition of congestion levies on new generation. The results suggest that this option would reduce the volume of new generation plant required and delay transmission upgrade projects anticipated under the

41 Intelligent Energy Systems (IES), Modelling of Transmission Pricing and Congestion Management Regimes, Report, 22 December 2006.

42 The basis of IES modelling is the Queensland region over a 14 year period from 2006/07 to 2020/21 and forecasts dispatch costs, transmission investment and generation investment under the three cases of the current market Rules and scenarios a) and b). The congestion levy will reflect the cost of transmission augmentation needed to relieve any congestion caused by the new generator location decision, in line with a causer-pays principle.

current arrangements. This would have the effect of substantially increasing dispatch costs, by $4.47/MWh on average, compared to forecast dispatch costs under the current arrangements. The Southern Generators state that although these results apply only to Queensland, they are indicative of the magnitude of dynamic efficiency savings that could be achieved if generator nodal pricing, via CSP, were to be introduced into other regions of the NEM.[43]

In the Commission's view, the assumptions used in the IES analysis and the extent to which the findings are sensitive to those assumptions needs to be fully interrogated before any firm conclusions can be drawn from this work.

3.5 NEMMCO Statement of Opportunities, Annual National Transmission Statement

As part of its annual Statement of Opportunities (SOO), NEMMCO publishes its Annual National Transmission Statement (ANTS). The ANTS provides an integrated overview of the current state and potential future development of National Transmission Flow Paths (NTFPs).[44] The ANTS also considers the current capability of the network and the historical utilisation and incidence of congestion.

The ANTS uses a market simulation model to develop a ten year forecast of network congestion in order to identify the need for NTFP augmentation from a market benefits perspective. Market benefits are assessed assuming short run marginal cost (SRMC) bidding by generators. The ANTS also develops conceptual augmentations, in consultation with jurisdictional planning bodies, taking information from their annual planning reviews into account.

The ANTS reports contain a number of indicators on the magnitude and impact of current and future congestion. The key measures are the Primary Market Benefit Indicators, which measure the total market benefits from removing all network constraints as determined by summing up the following measures:

- Reliability indicator – measures the total value of unserved energy (USE) valued at VoLL ($10,000/MWh) that can be avoided by relaxing network constraints;
- Operating cost indicator – measures the change in dispatch and production efficiency by allowing increased transfers from regions with low cost generating units as a result of reducing NTFP constraints; and

[43] "In the interest of time, we have asked IES to apply the theoretical solution only to new generators in Queensland, and NEM-wide materiality can be assumed by extrapolation. Despite this limitation, Queensland represents an excellent case study as it comprises roughly half of the load and generation growth of the NEM, it is geographically large and these 11 nodes encompass a very wide range of new entrant costs, from the cheapest to the most expensive in the NEM." LATIN Group, *Congestion Management Review – modelling of future efficiency gains*, 22 December 2006, p.2-3.

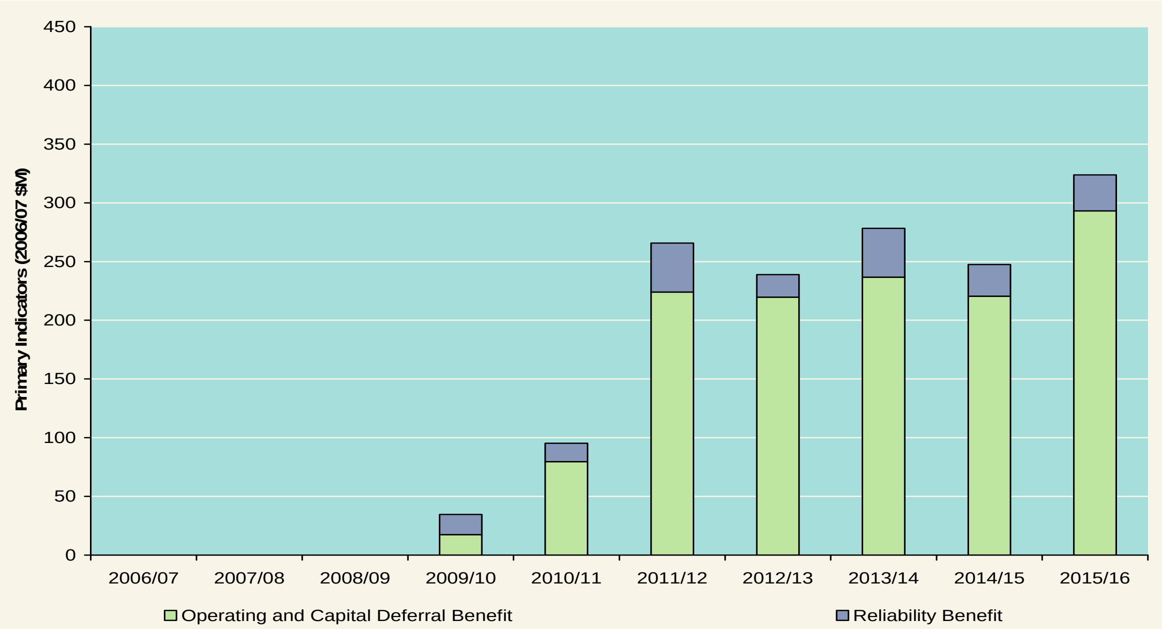
[44] A NTFP is defined by NEMMCO as a flow path that joins major generator or load centres, is expected to experience significant congestion across the next ten years simulation period, and is capable of being modelling.

- Capital Deferral Indicator – estimates the benefit from deferring some market driven generation as a result of reducing NTFP constraints. This is measured by comparing the total market entry capital investment in the constrained and unconstrained cases. A transmission augmentation can reduce periods of high prices in regions lowering the premium available to new generators and delaying new entry.

NEMMCO's Primary Market Benefit indicator seeks to measure some of the main impacts of congestion on economic efficiency. It considers the dispatch inefficiency of higher cost generation replacing low cost generation and also the beneficial impact from removing congestion on the costs of new investment. Figure 3.1 shows NEMMCO's calculated total market benefits for each year, broken down by reliability benefits and the combined benefits of capital deferral and operational cost savings. NEMMCO estimated the value of all congestion in the NEM (from 2009/10) onwards at $2.2bn.[45] The Commission understands that this does not account for any network investment beyond October 2010, even though such additional investment is likely to occur. This means that the information has limited usefulness to parties wishing to understand future likely levels or costs of congestion. It also has limited usefulness to the Commission in terms of indicating the magnitude of the likely future physical and financial trading risks associated with congestion.

[45] NEMMCO assumes that the market benefits will arise from 2009/2010 onwards as this would be the first year that any NTFP augmentation could be completed due to approval and construction lead times. The significant increase from 2010/11 to 2011/12 is because 2011/12 is assumed to the first year that benefits from deferring generation projects can be realised.

Figure 3.1 NEMMCO's Primary Indicators: Total Market Benefits, by year from removing all network congestion



Data source: NEMMCO, Statement of Opportunities 2005, Figure 8.2, section 8-13

3.6 Conclusion

The Commission has carefully considered the findings of the various studies on the materiality of congestion that have been undertaken to date. Each of these studies provides a partial view of the incidence or costs of congestion. While they have each been informative, none provides a clear indication of the gains in terms of improving efficiency or reducing participants' trading risks that could be achieved by taking policy action.

The Commission has examined a number of studies and measures of historical congestion and has considered whether the evidence suggests that there has been a material congestion problem. Its view is that while there are insights to be gained from each of the studies, no individual measure provides a robust indication of the materiality of mis-pricing in particular, or of congestion in general.

For example, the work undertaken by NEMMCO raises the issue of whether the observed incidence of mis-pricing is substantially driven by outage events or by changes to the formulation of constraints (especially in South Australia and Queensland). Further, while the NEMMCO analysis shows a large percentage of mis-pricing occurs in price bands below $300/MWh, it does not indicate whether the mis-pricing is trivial or substantial, let alone the impact of that mis-pricing on the efficiency of dispatch.

At this stage, there is no clear evidence before the Commission that mispricing due to system normal constraints is material or is having a significant adverse effect on dispatch efficiency.

In addition, the assumptions behind the IES analysis, as well as the extent to which the study's findings are dependent on the assumptions, require more detailed consideration.

The Commission's preliminary findings is that the currently available studies do not provide a sufficient basis for an informed conclusion on whether congestion in the NEM has been, or is a material problem. In particular, those studies do not provide evidence of the impact of network congestion on the economic efficiency of dispatch or trading in the NEM.

Over the coming months, the Commission's work program will focus on the incidence, trends and materiality of congestion. More specifically, the Commission intends to:

- undertake further analysis to assess the magnitude and materiality of congestion in the NEM;
- extend the analysis of mis-pricing undertaken by Dr. Biggar and NEMMCO to determine what factors have influenced the extent of mis-pricing observed in the data. In particular, the Commission intends to examine whether much of the mis-pricing is being driven by outages, rather than occurring during system normal conditions;
- determine whether there is scope for public reporting by NEMMCO of an annual measure or measures of congestion to inform market participants and improve locational investment decisions by load, generators and TNSPs; and
- assess whether historical congestion is a sufficiently large problem to justify adopting one of more options for intervention options to manage congestion, as discussed later in this paper.

Importantly, examining the impact of historical congestion is only useful as an indicator of future congestion problems. Greater information may allow for more informed decisions about whether specific congestion management actions should be undertaken. The Commission intends to assess the impact of historical congestion to determine the appropriateness of recommending intervention options for the management of congestion in certain circumstances.

The Commission welcomes any further views as to the ongoing issues it should consider in assessing the materiality of congestion in the NEM.

4 Congestion management under the existing Rules

There are a variety of mechanisms within the current Rules that directly or indirectly seek to manage congestion and the physical and financial trading risks it creates. This Chapter discusses these mechanisms to provide a basis for the consideration of options for changing the way congestion is managed in the NEM. In doing this, the Commission seeks to articulate the relationship between a potential constraint management regime and other market design features, as required by clause 3.2 of the MCE's ToR.

4.1 Categorisation of current Rules for congestion management

The existing Rules and NEM design contains a number of mechanisms that relate to either:

- the direct management of physical and financial risks associated with congestion; or
- the level of congestion, which may indirectly affect the physical and financial trading risks associated with congestion.

As explained in Chapter 2, the Commission considers that this division provides a useful taxonomy for both describing the existing types of Rules for managing congestion, as well as for discussing the options for changes to the existing arrangements. However, as also noted in Chapter 2, the Commission believes that the primary focus of the CMR should be on the first category of options, given that the Commission has examined incentives for managing the level of congestion through more efficient transmission investment and operation as part of its review of the economic regulation of transmission services.

4.1.1 Managing the trading risks arising from congestion

The mechanisms for the direct management of trading risks from congestion can be further broken into the following categories:

- Dispatch Rules – Rules surrounding the methodology for dispatching the market;
- Pricing Rules – Rules concerning the extent to which the costs of actual or expected congestion are priced in:
  - the spot market; and
  - the provision of network services;
- Settlement Rules – Rules relating to how spot market transactions are financially settled against the dispatch and pricing outcomes of the market;
- Risk management Rules – Rules providing for the specification and auctioning of IRSR units to assist in managing the basis risk from inter-regional contracting;

- Information Rules – Rules concerning the provision of information to the market on actual and potential network constraints. Such information can assist participants in managing their exposure to the physical and financial trading risks arising from congestion. As noted below, information Rules may also affect the occurrence of congestion in the longer term; and

- Intervention Rules – Rules providing for intervention in market dispatch through processes such as clamping, constraint re-orientation, and NEMMCO directions.

4.1.2 Mechanisms for reducing the level of congestion

The mechanisms in the Rules focussed on reducing or influencing the occurrence, duration or frequency of congestion can be further described as falling within the following categories:

- Investment and Operation Rules – Rules that seek to increase the actual or effective transfer capability of the transmission system. This can be achieved by:

  – investment in transmission assets or transmission alternatives – investment in transmission assets or certain network control ancillary services (NCAS) may increase network transfer capability.[46] Although investment in transmission alternatives (such as local generation or Demand Side Management (DSM)) may not actually increase network transfer capability, it could help reduce the likely extent of congestion with the existing level of transfer capability. To this extent, the impact would be similar to investment in transmission assets or NCAS;

  – more efficient network operation – such as more rational network outage scheduling or other changes to TNSP behaviour; and

  – greater coordination between TNSPs, NEMMCO, and participants; and

- Information Rules – Rules that assist participants (including TNSPs) in making future investment decisions may reduce or influence the occurrence of congestion in the longer term. Such Rules make provision for information regarding:

  – future transmission developments; and

  – anticipated new load and generation investment.

4.2 Rules for the direct management of trading risk

The Rules discussed in this Chapter are concerned with the management of trading risks that arise in the presence of congestion. These Rules do not seek to reduce or change the occurrence of congestion, although they may indirectly affect the timing, duration and frequency of congestion. Rather, the Rules discussed here relate to the

[46] An example of NCAS is the provision of reactive power. This could increase the limit of flow through the relevant line or cutset, thereby increasing network capability.

arrangements through which participants can manage their dispatch risks and basis risks.

4.2.1 Dispatch Rules

The current Rules for dispatching the NEM are largely contained in Chapter 3 of the Rules and include the following:

- a requirement that NEMMCO develop and use a dispatch algorithm (NEMDE) that maximises the value of spot market trade (based on participant bids and offers) subject to a range of constraints, including inter- and intra-regional network limitations;

- an ability for participants to revise their bids and offers (i.e. "rebid") right up to the time of dispatch;

- in the presence of network congestion, the optimisation of dispatch can result in the volume of a generator being scheduled:

  – below its desired level, given the RRP (i.e. the generator is constrained-off); or

  – above its desired level, given the RRP (i.e. the generator is constrained-on);

  In these circumstances, generators may have incentives to distort their offers or rebids as they attempt to match their dispatch volume with their desired output level given the RRN price;

- requirements for NEMMCO to determine and publish the network constraints used in NEMDE, and to publish the methodology used for determining constraints;

- obligations on TNSPs to provide NEMMCO with formal advice of network limits, which NEMMCO then uses as core information for constraint equations; and

- where congestion results in multiple generators competing for access to a limited network capability by bidding at the lower price limit of -$1,000/MWh (i.e. a bidding war), the Rules require NEMMCO to "tie-break" and apportion access to the network limit in proportion to the quantity offered (Rule 3.8.16).

In addition, Part 8 of Chapter 8A of the Rules provides for a number of transitional or temporary measures, including the requirement that NEMMCO must formulate constraints resulting from limitations on both inter-regional and intra-regional flows – this is regarded as clarifying NEMMCO's ability to implement fully optimised constraint formulations (clauses (a) and (b)).

Part 8 is currently due to expire on 31 July 2007, but may be extended to the earlier of 30 June 2008 or as otherwise determined by the Commission.[47]

4.2.2 Pricing Rules

The existing Rules for spot price determination help ensure that the dispatch costs of congestion (based on participants' bids and offers) are reflected in the spot market. Spot price determination takes account of transmission losses as well as constraints. Prices at RRNs can vary by more than the value of losses when constraints that affect flows between two RRNs bind. The location of binding limits on flows between regions may not be precisely at regional boundaries (for details, see Appendix 4 of CMR Issues Paper).

Important elements of the NEM pricing arrangements include the following:

1. As noted above, generators are effectively dispatched on a nodal basis using a network model that implicitly mimics the underlying physical network and its limits. However, the pricing of the market is on a regional basis and generators receive the RRN price (adjusted by their static marginal loss factor (MLF)) in the settlement process. As noted above this can create incentives for distorted bidding;

2. Generators who are constrained-off receive no compensation[48] for being unable to be dispatched, but are allowed to re-bid to manage their volume risks and hence spot market revenues. At the same time, the price these generators receive at settlement (the RRP) is greater than the price at their local node;

3. Generators who are constrained-on also receive no compensation,[49] but are also able to rebid to manage their volume risks and spot market revenues. If generators are constrained-on by the dispatch process, then they are currently precluded from being compensated by NEMMCO under clause 3.9.7. However, they may seek to negotiate a network support agreement with a TNSP under clause 5.5(f), which might provide them with a higher effective price for their generation than they would otherwise receive in the event of being constrained-on by the dispatch process;

4. Loads that can be voluntarily reduced (i.e. DSM) are entitled to make bids for doing so as a substitute to either additional generation or involuntary curtailment of supply;

5. The bulk of the costs of the shared transmission network is recovered through charges to loads, while generators pay only "shallow" connection costs.

47 AEMC 2007, *Draft National Electricity Amendment (Abolition of Snowy Region) Rule 2007*, schedule 2; and AEMC 2006, *Extension of the Participant Derogation in Part 8 of Chapter 8A of the National Electricity Rules*, (Draft) Determination, 14 December 2006, Sydney.

48 Both constrained-on and constrained-off generators are entitled to seek compensation from NEMMCO when directed to run or not run for reliability or security reasons.

49 Both constrained-on and constrained-off generators are entitled to seek compensation from NEMMCO when directed to run or not run for reliability or security reasons.

Generators may request TNSPs to undertake downstream augmentations that are not required to serve load requirements, but must pay the relevant costs and do not receive explicit financial or physical rights to the incremental transfer capability;[50] and

6. A process for altering the number of pricing regions and the locations of regional boundaries and RRNs is included in the Rules. This process is currently suspended by Rule 3.5.4 and is under review by the Commission in response to a Rule change proposal from the MCE.

In addition, the Rules for the pricing of network services (Chapter 6A) were recently revised as part of the review of the economic regulation of transmission services. In its Determination, the Commission decided that:

- generators should pay the costs directly resulting from their connection decisions, that is shallow connection;

- it is not appropriate at this stage for generators to contribute towards the costs of the shared network through prescribed generator transmission use of system (TUoS) charges – these costs should continue to be borne by electricity consumers;

- Cost Reflective Network Pricing (CRNP) and Modified CRNP are appropriate locational pricing methodologies for shared TUoS charges, although there should be scope for these to be developed further into the future; and

- to some extent price structures should be specified in the Rules.

This means that Rules for transmission pricing are unlikely to have much impact on participants' trading risks, in at least the short term.

The Commission stated that its position on transmission pricing was conditional on the outcomes of the CMR.[51] In particular, the Commission noted that the conclusions of the CMR may have implications for the appropriateness of the current broad allocation of Prescribed Transmission Services costs to electricity consumers.[52]

The new regime for negotiated transmission services (including new connection services) also provides important price signals to prospective investors relating to the costs of connecting to the network. These costs will vary depending on the location of the investment and the existing network infrastructure. However, once again, this is unlikely to have an impact on the trading risks of congestion in the shorter term.

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50 However, note that under the new chapter 6 Rules, generators paying for "negotiated services" that are connection services may be entitled to a contribution from later connecting parties (clause 6A.9.1(6)).

51 AEMC 2006, *Pricing of Prescribed Transmission Services*, Final Rule Determination, 21 December 2006, Sydney, p.3.

52 AEMC 2006, *Pricing of Prescribed Transmission Services*, Final Rule Determination, p.1.

4.2.3 Financial risk management Rules

The Rules also provide a regulatory framework for basis risk management products to facilitate inter-regional financial contracting in the presence of congestion. Some aspects of these products (IRSR units) were highlighted in Chapter 2.

The key elements of this framework include:

1. IRSR units – which entitle holders to a percentage share of the (positive) settlement residues accruing on a particular directional interconnector (e.g. Victoria to South Australia, Queensland to NSW). Typically, each IRSR unit represents the settlement residues accruing for a 1MW flow on an interconnector from the exporting to the importing region. However, the occurrence of network outages or differing levels of output of certain generators can mean that the value of one IRSR unit may be less than 1 MW multiplied by the average difference between the importing and exporting region's RRPs. Under these conditions, IRSR units would not be fully effective in mitigating trading risks (i.e. they will not be fully "firm"); and

2. Settlements Residue Auction (SRA) – for allocating IRSR units. SRAs are held by NEMMCO on a quarterly basis for IRSR units on each directional interconnector, up to one year in advance. At each auction, 25 per cent of the total number of IRSR units for each quarter of the following four quarters is auctioned. Participants are also able to make "linked" bids across quarters and/or across interconnectors, so that their bid for one type of IRSR unit is contingent on success in acquiring another type of IRSR unit. A linked bid enables a "strip" of IRSR units on different directional interconnectors to be acquired with a single bid, rather than having to attempt to secure the desired level of units in a series of separate bids for each interconnector.

There are a number of other Rules that address more general risks arising from participation in the NEM spot market and financial contract trading. However, these Rules do not relate to congestion as such and are therefore not described in detail in this paper.[53]

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[53] These more general Rules relate to matters such as the market price cap, and the Cumulative Price Threshold (CPT), both of which limit spot price volatility in the short term. The Reliability Panel is currently undertaking a comprehensive review of the reliability standard for generation and bulk supply and plans to review the reliability requirements for transmission by June 2008. The level of VoLL and the CPT will be examined in this comprehensive review.

The Rules also impose prudential requirements to provide participants with confidence in the integrity of spot market transactions. Contract market prudential requirements also apply and regulatory exemptions exist concerning the status and regulatory treatment of "electricity derivatives". The Commission has accepted a NEMMCO Rule proposal to enable some degree of offsetting of spot and contract market positions to reduce credit support requirements. Consultation with Sydney Futures Exchange (SFE) is ongoing to better specify a proposal to integrate NEMMCO settlement with SFE contracts and processes. The current proposal is not well specified.

Based on this regulatory framework, a range of financial contracts have developed. These range from simple standardised products (e.g. caps and swaps) to complex bespoke contracts with a high degree of optionality built in (e.g. look-backs, load following, etc.). Such arrangements include: (1) vesting

4.2.4 Information Rules

At present, considerable information about actual and future potential congestion is made available to the market. This information assists firms to evaluate the viability of new investments in load or generation and manage their trading risks.

The information available includes extremely short term indicators such as the market pre-dispatch schedule and short-term Projected Assessment of System Adequacy (PASA) to long range planning reports and workplans. In general, the Commission expects that the shorter timeframe information would be used more by participants involved in managing their existing operations, while the longer timeframe information would be more used by those contemplating new investment. This Chapter focuses on the information on short term constraints. Information of more relevance to investors is discussed in Chapter 4.3.1.

Shorter term information on constraints is currently available from a number of sources, including:

1. NEMMCO's Market Management Systems (MMS), which provides detailed information on the constraints used in dispatch, the degree to which they bind, and the market value of their impact on dispatch;

2. NEMMCO's Medium Term (MT-PASA), Short Term PASA (ST-PASA) and Pre-dispatch processes which indicate supply – demand balance projections taking into account network limitations. Pre-dispatch also indicates the pricing consequences of arising from the projected energy balance and network limitations, and pricing sensitivities;

3. Planned Network outage schedule, posted by TNSPs;

4. NEM Communications; and

5. The dispatch process and its outcomes, including generator dispatch targets from NEMMCO, regional reference prices, interconnector flow data, and outturn inter-regional settlement residues.

4.2.5 Intervention Rules

As noted above, Part 8 of Chapter 8A of the Rules provides for a number of transitional or temporary measures. As well as clarifying NEMMCO's ability to implement fully optimised constraint formulations, it also provides for the following interventions:

- where a network constraint leads to a significant counter-price flow between regions, NEMMCO must use an alternate constraint formulation for the expected

contracts imposed by governments as part of a reform process; (2) bilateral contracts (broker traded or direct between counterparties), which have a standard set of terms based on the International Swaps and Derivatives Association (ISDA) Master Agreement that can be varied by negotiation; and (3) exchange traded contracts and options, with standard terms imposed by the SFE.

duration of the counter-price flow – this is regarded as enabling NEMMCO to limit or "clamp" interconnector flows, as well as re-orientating some constraints to limit counter-price flows and negative settlement residues (clauses (c) - (d)); and

- special arrangements apply in the Snowy region of the NEM, including the CSP/CSC trial at Tumut and the Southern Generators Rule (clauses (f)-(p)).

Although the former set of provisions could be regarded as facets of the dispatch Rules – and indeed they follow the clauses on fully optimised constraints – there is an important difference. This is that these alternative or additional constraints are applied not to keep the network within secure limits, but for commercial or policy reasons. The rationale for those provisions is to limit negative settlement residues so that NEMMCO, and ultimately electricity consumers, are not required to fund them and thereby underwrite the value of IRSR units.

The special arrangements in place at Tumut involve a time-limited trial and therefore should also be regarded as an intervention in the management of congestion.

4.3 Rules influencing the occurrence of congestion

The Rules discussed in this Chapter are concerned with the likely future occurrence of transmission congestion. To the extent that the actual level of congestion changes over time, the physical and financial trading risks of congestion are also likely to change. The relationship between the level of congestion and the magnitude of trading risks may not be direct or proportionate. However, other things being equal, Rules that lead to increases or decreases in the level of congestion are likely to increase or decrease, respectively, the trading risks associated with congestion.

4.3.1 Investment and operation Rules

Most new investment in transmission assets is undertaken by TNSPs, whose revenues are regulated under chapter 6A of the Rules. TNSPs' revenues are regulated according to an incentive-based building block model, in which TNSPs are allowed to recover:

- a return *on* their capital base, including prudent capital investment;

- a return *of* their capital base (depreciation); and

- efficient operating and maintenance costs.

In addition, TNSPs can recover various "pass-through" amounts, which generally reflect unanticipated changes to their costs.

The Rules also implement a service performance incentive scheme that is intended to reward TNSPs for good service and penalise them for poor service.

Details of these arrangements are provided below.

4.3.1.1 Regulated investment in transmission and transmission alternatives

The Rules provide for a return on and of TNSPs' network investments to be recovered from transmission customers where the investments meet the requirements of Chapters 5 and 6 of the Rules. Chapter 5 requires TNSPs to conduct the Regulatory Test in respect of most of their investments. The Regulatory Test comprises a "market benefits" limb and a "reliability" limb. The market benefits limb applies a cost-benefit framework to network investment, where an investment only satisfies the Test if it maximises "market" benefits (being benefits to consumers, producers and transporters of electricity) compared to a set of network and non-network alternatives across a range of market development scenarios. The reliability limb applies a cost-effectiveness framework to an investment, where an investment only satisfies the Test if it minimises the cost of meeting a given reliability criterion compared to a set of network and non-network alternatives across a range of scenarios.

The alternatives that TNSPs must consider under the Regulatory Test include local generation and DSM. Where a non-transmission option proves to be superior to a transmission option, a TNSP may recover the cost of that option from customers as part of its allowed operating and maintenance cost, or as a pass-through item.

Most transmission flowpath investment in the NEM occurs pursuant to the reliability limb of the Regulatory Test. There are a variety of reasons for this, but a key one is that reliability criteria in place in many jurisdictions tend to require network investment to be undertaken prior to when it would be justifiable based on an assessment of net market benefits. The key exception to the predominant use of the reliability limb of the test is in Victoria, where the planning TNSP, VENCorp, applies a "probabilistic" approach to reliability standards. This effectively means that the market benefits limb of the Regulatory Test is used to assess all transmission investment in that jurisdiction.

In November 2006, the Commission made a Rule outlining principles for a revised Regulatory Test.[54] The principles provide the framework within which the AER makes the Regulatory Test. In so doing, they simplify and clarify the Test's requirements. These include the principle that application of the Test requires consideration of all *likely* alternatives, without regard to matters such as energy source, technology or ownership. This represents a change from the previous Regulatory Test, which only required that alternatives be genuine and practicable. The principles also require TNSPs to publish a request for alternatives where it is assessing a potential 'large new transmission network investment'. This should further simplify the market benefits limb of the Test. A reformed Regulatory Test could promote more efficient and timely transmission investment. This could, in turn, reduce the occurrence of congestion and potentially the physical and financial trading risks arising from congestion.

In any case, satisfaction of the Regulatory Test is not a sufficient condition for investment cost recovery by TNSPs. Under Chapter 6 of the Rules, TNSPs must submit a revenue proposal to the transmission regulator, the AER, prior to each

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[54] AEMC 2006, *Reform of the Regulatory Test Principles*, Final Rule Determination.

regulatory control period (5 years). The revenue proposal must include a figure for the cost of planned transmission investment over the forthcoming period sufficient to meet expected demand, comply with regulatory obligations, and maintain the quality, reliability and security of supply. The AER is obliged to accept the expenditure forecast if it is satisfied that it reasonably reflects efficient and prudent costs and realistic forecasts of demand and input costs. If the AER is not satisfied it is required to adopt a substitute forecast that meets the requirements of the Rules.

During a regulatory control period, TNSPs are allowed to recover a return on and of the agreed amount of capital investment, regardless of what they actually spend on investment. Similarly, TNSPs are allowed to recover the agreed amount of operating and maintenance costs, regardless of what they actually spend. The purpose of this approach is to provide TNSPs with incentives to minimise their capital and operating expenditures during a regulatory control period. At the end of each period, the *actual* amount of capital expenditure is added to the TNSP's regulated asset base. This means that a TNSP's incentives to minimise capital spending, as well as its penalties for increasing expenditure, are limited to the return on and of deviations from the agreed level for a maximum of 5 years.

In addition to the regular provisions, the Rules also provide separately for large and uncertain transmission investments. Such larger investments may fall within the separate "contingent projects" regime, in which case a TNSP may have stronger incentives to undertake the project and minimise the project's costs.

4.3.1.2 Last Resort Planning Power

The Commission has recently made a Rule providing it with a LRPP.[55] The LRPP allows the Commission to direct a Market Participant to undertake a Regulatory Test assessment for a particular network problem or transmission investment under certain circumstances.

The purpose of the LRPP is to ensure that appropriate consideration is given to transmission investment in circumstances where TNSPs' existing incentives to undertake transmission investment may be lacking.

Importantly, the power of direction can only be exercised as a "last resort" when all other methods of addressing a congestion problem have been exhausted. The Rule requires the Commission to be satisfied that no Regulatory Test is currently being conducted in relation to the problem; all alternative options have been exhausted; and but for the exercise of the power, the problem is unlikely to be addressed.

4.3.1.3 Service target performance incentive scheme

In undertaking its review of the economic regulation of transmission services, the Commission understood that financial incentives for TNSPs to minimise capital and operating expenditure could, by themselves, encourage TNSPs to allow service

[55] AEMC 2007, *National Electricity Amendment (Transmission Last Resort Planning) Rule 2007*, Rule Determination.

performance to degrade. Therefore, Chapter 6A of the Rules provides for the AER to develop a service target performance incentive scheme, whereby between 1% and 5% of each TNSP's revenue is "at risk", contingent on the TNSP's performance against a suite of performance measures.

The Rules require the service target performance scheme to be focussed on the appropriate *timing* of transmission system availability as well as on maximising the availability of the most valuable network *elements*. The scheme is intended to encourage TNSPs to provide greater reliability of the transmission system at times when it is most valued by transmission network users and in respect of those network elements that are most important to the determination of spot prices.

In January 2007, the AER published its first proposed set of guidelines for the service target performance scheme.[56] The proposed guidelines indicate that the scheme is heavily based on the AER's pre-existing "service standards" regime. The AER has noted that it is in the process of developing incentive scheme parameters based on market impacts,[57] and intends to incorporate any necessary amendments into the scheme to reflect these parameters when they are finalised, ideally before 30 September 2007. This will allow them to be applied to the forthcoming Transend, EnergyAustralia and TransGrid price reviews.

4.3.1.4 Comprehensive Reliability Review

The Commission has requested the Reliability Panel[58] to undertake a comprehensive and integrated review of the effectiveness of NEM reliability settings, including whether there may be a need to improve or change them. The panel is focusing on whether an adequate level of generation and bulk transmission is made available.

The Panel intends to publish its draft decisions in March 2007. The outcomes of this review may have some implications for the level of congestion in the longer term.

4.3.2 Information rules

The previous Chapter highlighted key Rules relating to the provision of short term information to the market. The discussion in this Chapter deals with longer term information provision, likely to be of more interest to investors. This information

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56 Australian Energy Regulator, *First Proposed Electricity Network Service Providers Service Target Performance Incentive Scheme*, Version No.01, January 2007.

57 Australian Energy Regulator, *First Proposed Electricity Network Service Providers Service Target Performance Incentive Scheme*, Explanatory Statement and Issues Paper, January 2007, pp.4-5.

58 The NEL requires the AEMC to establish the Reliability Panel in accordance with the National Electricity Rules. The role of the Panel is:

- to monitor, review and report on, in accordance with the Rules, the safety, security and reliability of the national electricity system;
- at the request of the AEMC, to provide advice in relation to the safety, security and reliability of the national electricity system; and
- any other functions or powers conferred on it under the Law and the Rules. Clause 8.8.1 of the Rules sets out the functions of the Panel in more detail.

could have an impact on the level of congestion, and hence the trading risks arising from congestion, in the longer term.

The sources of information include:

1. NEMMCO's Annual SOO and ANTS, which focuses on NEM-wide reliability and congestion along the NTFPs that comprise inter-regional interconnectors. The SOO/ANTS also provides a projection of various market parameters, and the opportunities that arise from them at various stages on the forward timeline; and

2. Annual Planning Reports by jurisdictional network planning bodies, which primarily focus on the maintenance of network reliability within each TNSP's, jurisdiction-based, franchise area. These APRs, together with TNSP consultations and reports on large network augmentations (required under clause 5.6.6(h) of the Rules) detail emerging network limitations within each TNSP's service area over the next 5 to 15 years, and outline a range of possible options for addressing the limitations.

The ability of the market and also of preparers of projections such as SOO/ANTS to predict the physical power transfer capability of the transmission network is currently limited, with no specific party responsible for maintaining or delivering a defined level (or performance envelope) of physical network capability at a future time.

Finally, network access and connection arrangements are governed by Chapter 5 of the Rules, and broadly require investors to make a connection application to the relevant TNSP. Pursuant to this application, the TNSP is required to design connection assets, advise the necessary technical requirements of the new plant (per the technical standards) and engage in negotiation over the terms of a connection agreement. TNSPs are entitled to charge for these services.

4.4 Recent policy debate on existing transmission arrangements

The ERIG discussion paper on transmission published in November 2006 highlighted a number of perceived shortcomings of the existing arrangements for transmission planning, investment and operation.[59] These were:

- a lack of commercial incentives for generators to locate efficiently in respect to the transmission network;

- a lack of incentives for both efficient operation of the existing transmission system and efficient investment in the system; and

- a lack of coordination of investment in the transmission system on a national basis.

ERIG proposed a way forward on these matters that involved:

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59 ERIG, *Discussion Papers*, pp 104-154.

- harmonisation of jurisdictional reliability standards;
- consideration given to replacing the Regulatory Test with a two-stage process for transmission investment, involving:
  - the establishment of a National Transmission Network Development Plan (Plan) for the long term efficient development of the grid, replacing the ANTS; and
  - a requirement for TNSPs to consult on individual projects to ensure each project is appropriate, takes proper account of non-network options and is consistent with the long term Plan. This stage would incorporate an assessment based on the Regulatory Test, integrating both the "reliability" and "market benefit" limbs of the present Test; and
- adoption of a national planning approach based on one of three options, spanning:
  - a modified status quo involving an independent national planner to disseminate information;
  - an independent national planner to both disseminate information as well as provide advice on efficient longer term investment options; and
  - the formation of a not-for-profit National Transmission Service investment decision-maker. Such a body could be established as a standalone entity or under the auspices of the Commission (like the Reliability Panel) or NEMMCO.

In addition, ERIG commented that there was a need to strengthen locational signals to generators. However, it did not propose any specific mechanisms to provide these signals.

The Commission considers that the outworkings of the CoAG process in response to the ERIG Final Report could lead to changes to the NEM in several of the areas highlighted above. Changes in these areas would be likely to affect both the magnitude of participant trading risks as well as the manner in which participants can manage those risks. Given that CoAG is considering these matters, the Commission does not intend to investigate major changes to either reliability standards, the Regulatory Test or planning responsibilities (other than its current work on the LRPP) within the CMR.

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5 Overview of the options for managing congestion

In examining the options for reforming the existing congestion management regime, it is useful to group options into the two key elements of the terms of reference for the Commission's review. Specifically options that:

- directly improve the ability of participants to manage physical and financial trading risks – clauses 3.1 and 3.2 of the ToR; and
- indirectly improve the ability of participants to manage trading risks by reducing the future level of congestion – derived from clause 3.1 of the ToR.

In relation to the first group of options, specific options for consideration include:

- more granular pricing of generation (and potentially load) – to address the problem of mis-pricing;
- firmer risk management instruments – to address the problem of hedging for basis risk;
- provision of more or better information on likely congestion – to improve the underlying conditions for managing congestion by assisting participants to predict and respond to their physical and financial risks; and
- intervention – the imposition or removal of interventions such as clamping and re-orientation may improve the firmness of hedging instruments.

The second group of options include:

- increasing the actual or effective transfer capability of the existing transmission system in an economically efficient manner; and
- provision of more or better information on likely transmission, generation and load developments – to promote efficient locational decisions for new capacity and reduce future trading risks.

As noted in the previous chapter, the Commission has already undertaken substantial work on the matter of transmission investment and incentives and therefore does not intend to pursue further consideration of these issues as part of the CMR. The Commission is interested in receiving submissions on whether there are specific issues relating to transmission network incentives that should be further pursued in the context of this review.

On the issue of improved information, the categorisation above indicates that information can be regarded as both a measure for directly assisting participants to manage their trading risk as well as reduce the future extent of trading risks by influencing investment decisions. While it may be difficult to maintain a strict separation between the types of information that belong in either category, the Commission considers that it is nevertheless worthwhile to acknowledge that better information has both short term and long term impacts on the ability of participants to manage the trading risks arising from congestion.

It should also be noted that intervention options may be available to NEMMCO that are not specifically targeted towards managing congestion, but have the indirect or incidental effect of reducing (or increasing) the trading risks of congestion. For example, NEMMCO is empowered to issue directions to participants to maintain or restore power system security and reliability. Such directions may have the consequence of alleviating congestion. In a longer term sense, NEMMCO historically had the power to procure reserve energy from the market to help meet anticipated supply shortfalls. By bringing forward additional supply or reduced demand, this action may reduce actual congestion as well as the costs of congestion. The Commission has decided to not consider these issues further as part of the CMR, although it acknowledges that there are outstanding questions relating to investment incentives that may require further review and consideration.

Finally, the Commission reiterates that whether it ultimately decides to recommend any option or options to the MCE will be contingent on its parallel work program on the materiality of the impacts of congestion. The Commission is of the firm view that options for change to the NEM arrangements should be *proportionate* to the materiality of congestion and its impact. As noted in Chapter 3 above, the Commission's view of the materiality of congestion is evolving in the light of the studies undertaken to date and its ongoing work program in this area.

5.1 Direct management of trading risk

5.1.1 More accurate pricing of congestion

The first potential option for reducing trading risks arising from congestion is by providing more accurate pricing of congestion through a greater number of generator pricing points. Generally speaking, congestion resulting from binding limits on flows between two regions is currently priced in the NEM, while congestion resulting from limits on flows within regions might not be priced. Congestion arising on transmission lines between regions is priced through the scope for RRPs to diverge to reflect the relative scarcity of electricity in each region. In contrast, congestion wholly resulting from flows within regions might not be priced because all transactions within a region are settled at the same RRP. Under the Rules, intra-regional congestion that does not affect the supply of energy to the RRN does not affect the RRP, whereas intra-regional congestion that does affect supply to the RRN does have an effect on the RRP.[60] In reality, most transmission limits are affected by both inter- and intra-regional flows and generator outputs. This means that even constraints that appear to be located well within a region can cause inter-regional price separation when they bind. Such "hybrid" constraints are partially priced in the current regional boundary structure.[61]

As noted in the previous Chapter, more refined pricing for settlement purposes could reduce generators' dispatch risk by reducing the disconnect between bidding, dispatch and settlement – alleviating the mis-pricing problem. In so doing, more

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[60] See CMR Issues Paper, Appendix 4.

[61] See CMR Issues Paper, Appendix 5 for further details.

refined generator pricing could alter generators' incentives to bid in ways to secure or avoid dispatch (e.g. offering capacity at -$1,000/MWh or $10,000, respectively), by re-aligning dispatch, pricing, and settlements. This may lead to greater dispatch efficiency if it involves generators not being encouraged to bid at extreme levels to avoid being constrained-on or off. The result of more granular pricing may therefore be a dispatch process that meets the same level of demand at a lower resource cost.

On the other hand, as noted in Chapter 2, more refined pricing of congestion may also increase generators' incentives to exercise transient market power in transmission constrained load pockets. To the extent this occurs, it could lead to an increase in the economic costs of dispatch, as higher-cost plant displaces lower-cost plant in the dispatch "merit order". However, a regional pricing structure may provide greater incentives and opportunity for dominant generators to exercise transient market power, and enable them to do so over a larger volume of electricity (or customer base) than would occur under nodal pricing. Such an exercise of market power can be masked by the regional pricing structure and is likely to have a more significant negative impact on the economic costs of dispatch than the exercise of transient market power in transmission constrained load pockets, whose demand levels are a fraction of the total regional load.[62]

The Commission has found through its analysis of several region boundary Rule change proposals to date that determining the balance of these impacts on dispatch efficiency typically cannot be resolved conceptually.[63] It generally requires the use of simulations based on spot market modelling of a form that allows for strategic bidding behaviour. Ideally, this should capture the interdependencies between the bidding strategies of all influential generators.

In the longer term, the outcomes of spot market dispatch could be expected to flow through to other decisions. For example, to the extent more refined pricing leads to more efficient dispatch, it may also lead to lower, more cost-reflective retail prices, which could increase consumption and economic welfare. These "competition benefits" are recognised within the Commission's analytical framework.

If more refined pricing leads to more efficient dispatch, it could also promote more appropriate generator locational decisions. For example, pricing congestion could mean that generation investors face price signals to locate in load-rich areas instead of generation-rich areas. This could reduce the delivered cost of electricity, for the long term benefit of consumers, in line with the requirements of the NEM Objective.

At the same time, the Commission notes that where congestion is not priced, dispatch risk does provide prospective investors in generation with some non-price locational signals. In particular, generation investors locating in areas with scarce transmission capacity may not be able to *wholly* mitigate their dispatch risks by

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[62] Harvey, S.M. and Hogan, W.W. 2000, "Nodal and Zonal Congestion Management and the Exercise of Market Power", Harvard Electricity Policy Group, Cambridge, Mass., 10 January 2000. http://ksghome.harvard.edu/~whogan/zonal_jan10.pdf

[63] AEMC 2006, *Management of Negative Settlement Residues in the Snowy Region*, Final Rule Determination, Appendix A, p. A31-A36; AEMC 2007, *Abolition of Snowy Region*, Draft Rule Determination, p. 29-37.

offering output at -$1,000/MWh or bidding inflexible. Further, generation investors already need to consider a multitude of variables in making their locational decisions. These include the local availability and cost of:

- fuel for generation – for example, the price and supply reliability of coal and gas may vary substantially across locations within the NEM jurisdictions;
- water for cooling – a plentiful supply of water is required for thermal power stations, although some can be recycled;
- suitable land – a substantial area is required for a power station site; and
- skilled labour for plant operation and maintenance –power stations require a range of staff for operation and maintenance.

On the load side, individuals and investors in electricity-consuming businesses also have a range of factors to consider in deciding where to locate. Given the small proportion that electricity charges comprise of the average household or small business budget, it would be unlikely that a household or small business owner would ever choose where to reside based on electricity prices. Larger industrial users are more likely to consider electricity prices in making locational decisions. But even for them, other factors such as availability of skilled labour, proximity of low-cost raw materials, input and output transport links and land availability and prices are likely to weigh at least as heavily as electricity prices.

In summary, the issue for the Commission is determining how more refined pricing can lead to *incrementally* more efficient outcomes in practice, thereby promoting the NEM Objective.

5.1.2 Firmer risk management instruments

As noted above, the current IRSR units tend not to provide a fully firm hedge for inter-regional contracting. Further, if more refined pricing of congestion is undertaken to overcome the mis-pricing problem, participants' basis risks may be increased. This suggests that the availability of additional and/or firmer risk management instruments would need to accompany any increase in the pricing granularity of the market.

In some cases, the increased basis risk arising from greater pricing granularity may be sufficiently addressed by the creation of new IRSR units across the new directional interconnectors. In fact, by potentially reducing the extent of distorted bidding behaviour caused by mis-pricing, the new IRSR units may be collectively firmer than the old IRSR units. However, this assumes that transactions and execution costs of obtaining the additional IRSR units are small, which is a matter the Commission is intending to explore more fully.

Various modifications to the existing IRSR instruments could be made that could potentially make them a more effective tool for managing inter-regional basis risk. These are discussed in Chapters 6 and 7.

In other cases, greater pricing granularity may lead to loops between pricing regions. As noted earlier, in the presence of such loops, IRSR units do not provide a firm hedging instrument. In fact, as noted earlier, in the presence of such loops it is likely that negative settlement residues will arise on at least one IRSR fund. In these cases, more fundamental changes to IRSR instruments may be necessary.

Other options for hedging basis risk may also be worthy of consideration. FTRs in one form or another have been used in North America for some time. Alternatively, CSCs could be applied more broadly. Another option is the "constraint-based residues" approach developed by Dr. Biggar.

Chapter 7 discusses some of these less familiar options.

5.1.3 Improved information on likely congestion

Another means of assisting participants manage the trading risks of congestion is the provision of more or better information on actual or likely congestion. This may enable participants to:

- be better prepared for occasions when they may be constrained-on or off, facilitating their management of dispatch risk; and
- enter a more appropriate volume, type and duration of financial contracts with inter-regional participants.

5.1.4 Interventions

Interventions in the dispatch process such as clamping or re-orientation may reduce the firmness of risk management instruments. The reduction in IRSR firmness for northward trading was an issue raised in the Commission's considerations of the Southern Generators' Rule change proposal.[64] Such impacts can arise where counter-price flows occur due to network loops.

Under different circumstances, intervention to prevent or limit counter-price flows may actually improve the firmness of IRSR units. This could occur in a linear network where transmission limits are affected by both interconnector flows and generator outputs. This suggests that the removal of clamping may not result in an unambiguous improvement. Other intervention options may therefore be worth considering as a replacement for clamping in this context.

[64] AEMC 2006, *Management of negative settlement residues in the Snowy Region*, Final Rule Determination, 14 September 2006, Sydney.

5.2 Assisting risk management by influencing the level of congestion

5.2.1 Increasing the actual or effective transfer capability of the transmission system

To the extent the actual occurrence or duration of congestion can be reduced, this could ameliorate participants' trading risks arising from congestion. The most direct way of reducing congestion would be through investment in transmission assets, such as lines, switchgear, transformers and reactive plant. However, it could also involve regulated or non-regulated investment in transmission alternatives such as local generation or demand-side management options that had an impact similar to network augmentation.

Transmission system capability could also be enhanced by more efficient operation of the existing network, so that its transfer capability is maximised when it is at greatest value to the market. For example, TNSPs could be given stronger incentives to undertake transmission maintenance at times of off-peak loading on the network. In this context, the Commission's recent work on the economic regulation of transmission should enhance the ability of the AER to put such incentives in place. However, as transmission capability is a joint function of transmission infrastructure, load and generation patterns and NEMMCO management of the power system, there is a limit to what can be achieved in this manner without clarifying and/or rearranging the responsibilities and accountabilities of TNSPs, NEMMCO and market participants. Options involving such change are discussed in Chapter 7.

5.2.2 Improved information on future investments

As well as directly helping to reduce the trading risks arising from congestion, better information provision may also improve the long term efficiency of participants' operational and investment decisions. This may reduce the future level of congestion and hence, the future trading risks imposed by congestion.

6 Incremental options for change to the congestion management framework

This Chapter discusses potential *incremental* changes to the existing market arrangements that could assist participants in managing the physical and financial risks arising from congestion. Chapter 7 discusses options for more fundamental changes to assist participants manage the trading risks stemming from congestion.

In evaluating these options, the Commission intends to examine the likely effectiveness of each option at managing physical and financial trading risks, as outlined in Chapter 5. In addition, in developing its draft recommendations as to options, the Commission will be mindful of the overall costs associated with implementing an option and the benefits that are likely to accrue. While historical measures of congestion will assist with this assessment, it will be necessary to consider what the future impacts may be.

In presenting each of the incremental options, the same distinction is used as in the previous Chapter between options that:

- directly assist in the management of physical and/or financial risks associated with congestion; and
- influence the occurrence, duration or frequency of congestion, which may indirectly affect the physical and financial trading risks associated with congestion.

For each option or topic, this Chapter explains:

- whether the Commission intends to further investigate the option or topic; and
- if so, the types of issues that the Commission will be investigating – for example:
  - the potential capital, operating and implementation costs (where applicable);
  - whether an option is self-funding or will require consumers or other parties to underwrite funding shortfalls;
  - the technical feasibility of implementing the option on a localised basis; and
  - whether allocative or distributional decisions need to be made in order to implement the option.

The reason for investigating the technical feasibility of localised implementation of targeted congestion pricing mechanisms, such as CSP/CSC, is that the CMR ToR specifically requires the Commission to identify options that could be applied to manage material congestion *until it is addressed by investment or regional boundary change* (clause 3.2). The Commission was not asked to develop a regime for long term market-wide application. The Commission also notes that CSP/CSC arrangements were originally envisaged as being workable for only a relatively small number of locations (up to five) across the NEM at any one time.[65]

With respect to options for both incremental and fundamental change, the Commission highlights its comments above that the merits of *any* change are contingent on its parallel work program on the materiality of the impacts of congestion. It is the comparison of the options with the consequences of existing congestion that reveals whether those options are worth implementing.

6.1 Rules for the direct management of trading risk

6.1.1 Dispatch Rules

Under clauses (a) and (b) of Part 8 of Chapter 8A of the Rules, NEMMCO is required to formulate constraints that may result from limitations on both inter- and intra-regional power flows. NEMMCO has interpreted this to support the use of "fully optimised" constraint formulations, where all terms (generator outputs and interconnector flow terms) that may affect a constraint are placed on the "left hand side" of a constraint equation. This implies that NEMMCO has the ability to control these terms for each 5-minute dispatch interval.

In its Statement on Transmission, the MCE has indicated a policy decision supporting the use of the fully optimised constraint form.[66] This MCE decision was broadly supported in industry submissions to the Commission's CMR Issues Paper.[67] NEMMCO is currently transitioning to that form of constraints across the NEM.

Gradual implementation of fully optimised constraints could change the incidence and impacts of congestion on the network. NEMMCO has stated that the fully optimised form enables them to exercise greater control over transmission system elements, which may facilitate the use of higher transmission limits. Other things being equal, this should increase the level of security constrained transmission capacity available thereby reducing the cost of dispatch and increasing economic welfare more generally.

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65 CRA 2005, *NEM - Transmission Region Boundary Structure*, Final Report to the MCE, April 2005, states:

- "The [CSP/CSC] regime is most suited to manage a small number of local conditions under the broader regulatory framework; it would become overly complex if used universally across the NEM. Our expectation based on the history of the NEM and analysis of the potential level of congestion under the investment framework, is that the regime might be applied to a relatively small number of key points of congestion, say five, at any one time across the NEM." (p.4)
- "For the avoidance of doubt we note that the CSP/CSC regime is primarily a contract regime. It is specifically designed to compliment the broad region structure recommended within the report to manage material and persistent congestion. It could not operate as a nodal regime without significant change and is not suited to widespread use within the NEM as it would become unwieldy." (p.55)

66 Ministerial Council on Energy, *Statement on NEM Electricity Transmission*, May 2005, p7.

67 The key exception being the Macquarie Generation submission, 17 April 2007, pp. 2-3.

On this basis, the Commission suggests that the Rules could be amended to confirm NEMMCO's interpretation of Part 8 and insert clauses (a) and (b) in Chapter 3 of the Rules, which contains the bulk of the Rules for spot market operation. The Commission seeks stakeholder views on the appropriateness of such an amendment.

6.1.2 Pricing Rules

Incremental changes could be made relating to the granularity of pricing in the NEM.

6.1.2.1 Regional boundary change

In the Commission's view, one incremental means for increasing the degree of pricing granularity in the NEM is by providing a clearer, and more transparent process and criteria for evaluating regional boundary reviews.

The Rules, and previously, the Code, have always incorporated provisions allowing for changes to the regional boundary structure. These provisions are presently focussed on technical criteria and annual reviews by NEMMCO.[68] MCE concerns about this relatively frequent review process, the threshold for changing boundaries, and the potential impacts on business certainty and jurisdictional arrangements for retail pricing for small customers, resulted in a moratorium being imposed on regional boundary change pending a review.[69]

In 2004 the MCE commissioned a report by CRA to examine options that allowed for a slower evolution of the NEM's regional pricing structure that might otherwise occur under the existing criteria and process in the market Rules (or Code, as it was then). CRA's report to the MCE recommended a new, staged, approach to reviewing region boundaries that had less frequent reviews of the NEM's region boundaries, but allowed a number of targeted measures for more efficiently pricing congestion within regions in the period prior to any changes in the NEM's regional pricing.[70] The MCE began a public consultation process in late 2004 on the recommendations put to it, which was not completed. Instead, the MCE directed the AEMC to have regard to submissions made to its unfinished consultation process on CRA's recommendations in the context of the CMR and the MCE's Rule change proposal on changing the process and criteria for region boundary changes.

Re-examination of the process and criteria for boundary change would not radically change the institutional or regulatory design of the market, but could lead to changes to the regional structure of the market. Further, the MCE stated in its Statement on

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68 Under the existing Rules, congestion warranting boundary change is defined as involving a constraint binding for at least 50 hours per year (Rules 3.5.1-3.5.2). The existing Rules also include a process for annual reviews of region boundaries (Rule 3.5.3).

69 See clause 3.5.4 of the Rules, which gives effect to the moratorium.

70 For the recommendations see: CRA, *Region Boundary Structure*, September 2004. For further detail see: CRA, *NEM Regional Boundary Issues: Theoretical Framework*, *Final Report*, submitted to the MCE, Melbourne, 14 September 2004; and CRA, *NEM Regional Boundary Issues: Modelling Report, Final Report*, submitted to the MCE, Melbourne, 16 September 2004.

Transmission that incremental changes to regional boundaries are acceptable so long as they are justified on the basis of robust criteria.[71]

The MCE has proposed a Rule change to reform the regional boundary change process that was largely based on the recommendations made to it in 2004. The request seeks to promote clarity in both the process (including frequency, timeframe and thresholds that trigger a review of regional boundaries) and criteria to be applied to regional boundary change. The key points it seeks to make are:

- boundary changes should be considered in response to an application by a participant rather than on a periodic basis;

- boundary changes should only occur where congestion is material and enduring and has not been addressed by investment either before or after the AEMC has invoked its LRPP;

- the AEMC should consider all boundary change options and variations to determine the configuration that best delivers the NEM Objective;

- changes should come into effect with a sufficient lead time to address commercial and economic considerations (the suggested implementation period is 3 years); and

- criteria for boundary change should be forward-looking and economically-based, with minimum net benefit thresholds to apply.

Chapter 2 noted that the MCE ToR requests the Commission to consider congestion management mechanisms to apply *prior* to the implementation of a regional boundary change. For this reason, the Commission believes that changing the *criteria* for regional boundary change is strictly beyond the remit of the CMR. However, there is likely to be overlap between the process for regional boundary change and the triggers and duration of any interim congestion management mechanism. Furthermore, as noted in Chapter 1 above, the Commission has received a Rule change request from the MCE regarding the reform of regional boundaries. These issues will be discussed in Chapter 8 below on the packaging and sequencing of options.

6.1.2.2 Pricing for constrained-on generation

Another option that the Commission considers could be regarded as an incremental change from current arrangements is the provision of payments to "constrained-on" generators (only).[72] Under the existing Rules, as noted above, payments to generators that are constrained-on are not made as a matter of course. Rather, generators who declare themselves unavailable but are then directed to generate by NEMMCO for security or reliability reasons can seek compensation from NEMMCO. However, a more general regime of payments to constrained-on generators could be

71 Ministerial Council on Energy, *Statement on NEM Electricity Transmission*, May 2005, p4.

72 As noted above, constrained-on generators are those that are dispatched under the current regional market design even though their offer price is higher than the relevant RRP.

developed. The key rationale for a constrained-on payments regime would be an amelioration of incentives for generators to bid their plant unavailable or offer to supply electricity at extremely high prices (e.g. $10,000/MWh). In some cases, constrained-on payments offer a means of lowering the total costs of dispatch, by allowing additional flows of cheaper energy into a region that otherwise would have relatively high prices arising from congestion.[73]

Constrained-on payments raise a number of issues on which the Commission is keen to understand the views of stakeholders.

The first issue is determining the appropriate methodology for calculating constrained-on payments. One option is for the payments to be based on the difference between the generator's offer price and the RRP. Another option is for the payment to be based on the difference between the generator's nodal shadow price and the RRP. Both options are likely to lead to similar results, as in the former case, generators would have incentives to rebid their offers up to their shadow nodal price. However, such an arrangement could produce uncertainty amongst generators and would sit uneasily in a market that did not otherwise operate on a pay-as-bid basis.

In terms of the implementation of a constrained-on payments regime, there are three options for funding such payments. The first is an uplift on energy transactions. The advantages and disadvantages of this approach were canvassed in the Issues Paper and submissions were generally opposed to this approach (see Appendix A). The second funding option is through payments funded by an increase to transmission charges. The Commission considers that such payments could constitute a natural extension to the existing scope for payments under network support contracts. However, the difference is that while NEMMCO would determine when and to whom payments would need to be made, the funding would come from TNSPs. TNSPs would thus presumably expect to be able to pass-through such payments with minimal regulatory scrutiny or impact. This raises questions about the governance of, and accountability for, such a regime.

The third option is for NEMMCO to fund such payments out of energy market settlement or IRSRs such as through a CSP-type mechanism (see below). This would constitute a more fundamental change to the existing NEM arrangements because it could potentially change:

- the funds available to holders of IRSR units and thereby affect the firmness of the hedge provided by those instruments; and
- settlement payments made to generators whose output directly affects binding constraints.

[73] This is referred to as a gatekeeper generator. Constrained-on payments can be an economically efficient form of "side-payment" to a generator that is in a position to reduce the social costs arising from the externality effects of network congestion (i.e. total cost of dispatch), but is not sufficiently motivated to do so based purely on the RRP.

At the same time, imposition of CSPs may still raise issues of basis risk management for generators, although the "risk" in this case relates to the receipt of additional payments.

It should also be noted that constrained on payments could also introduce an overall wealth transfer to generators in the NEM. The Commission considers that the materiality of such a transfer would need to be understood as a prerequisite to any implementation of such an arrangement.

The Commission intends to investigate these matters further through a specific work programme. In particular it intends to examine:

- how a system of "constrained-on" payments could/should operate;
- the impact on the management of physical and financial trading risks; and
- how the payments can be funded, and implications for incentives.

The rationale for a regime for payments to constrained-on generators raises the question of whether it should be coupled with a regime for "constrained-off payments". In this context, the Commission considers it vital to ensure clarity over the meaning of this term. One interpretation of constrained-off payments is that they involve payments *from* constrained-off generators[74] to the market or network operator to reduce the incentive for these generators to bid below resource cost in order to be dispatched. If a constrained-off generator were required to pay the difference between the RRP and its local nodal shadow price (such that it ultimately receives its nodal shadow price on its output), it would be far less inclined to bid below cost. This could help improve the economic efficiency of dispatch.

However, as such a regime would make the relevant generators worse off, the Commission does not consider that it belongs within the category of incremental changes to the Rules. The combination of constrained-on and constrained-off payments is discussed in Chapter 7 in the context of the CSP instrument.

On the other hand, constrained-off payments are sometimes used to refer to "compensation" payments *to* generators that are constrained-off and not able to be dispatched at their preferred level given the RRP. Such a regime effectively involves constrained-off generators being compensated for their inability to sell their output at the prevailing RRP.

The Commission has two main concerns with the compensatory form of constrained-off payments. The first is that they may promote inefficient dispatch and locational incentives for generators – generators are rewarded for locating in constrained parts of the network and offering their capacity below cost. A second concern with compensatory constrained-off payments is that they could enhance and formalise a right of access for constrained-off generators to the RRP beyond the extent to which this is presently recognised in the Rules and the public policy settings under which the CMR is operating. The Commission is of the view that if effective rights of access to existing transmission capacity are to be allocated to particular parties, this should

[74] As noted above, constrained-off generators are those that are not dispatched under the current regional market design even though their offer price is lower than the relevant RRP.

be considered a fundamental change to the market arrangements. One transparent way of effecting such rights allocations is through the use of the CSC instrument, discussed in Chapter 7.

The Commission seeks the views of stakeholders on whether constrained-on (but not constrained-off) payments should be considered as an option for incremental change to the NEM arrangements.

6.1.3 Improvements to IRSR instruments

6.1.3.1 IRSR enhancements

The existing IRSR instruments could be modified or fundamentally changed to improve their effectiveness as a mechanism to manage basis risk. While there are a number of possible reforms to the IRSR instruments, only relatively minor changes are discussed in this Chapter.

First, it follows from the existing market design that changes to the regional boundary provisions leading to more or less regions would lead to a change in the nature and number of IRSR units to be auctioned. This could properly be described as a consequential impact of boundary change rather than a fundamental change in itself. Second, the volume of IRSRs that it is appropriate to auction for any given directional interconnector may also be affected by arrangements designed to improve TNSP performance or coordination between TNSPs, NEMMCO and market participants. Once again, this would be an operational consequence of other changes to the market rather than an independent change to the character of IRSRs.

Leaving aside these consequential impacts, potentially beneficial incremental changes to the design of IRSRs may also be possible. These include issues raised in stakeholder responses to the Issues Paper (see Appendix A for details), such as, increasing the duration of some IRSR units to more than one quarter, in order to facilitate longer-term inter-regional contracting.

All of these changes would require changes to the SRA Rules and the auction algorithm. The Commission intends to look closely at these options through a work programme and seeks specific comments and proposals from stakeholders on their merits and implications.

6.1.4 Recovery of negative residues

On 30 March 2006, the Commission made a Rule proposed by NEMMCO that altered the way NEMMCO recovered outstanding negative settlement residues. The Rule enables NEMMCO to recover outstanding net negative residues accruing on a directional interconnector from the following quarter's auction proceeds for that directional interconnector. It reduced NEMMCO's recovery period for these negative residues from up to two years, to around three months.[75]

The Commission placed a three year sunset on the Rule to highlight that it did not address a range of other issues surrounding the management of negative settlement residues that had been raised in submissions on the Rule change and the CMR Issues Paper. For example, a few submissions raised the issue of NEMMCO's practice of netting negative from positive residues within a billing week. The Commission considered that these other issues should be addressed in the CMR.

The CMR's terms of reference require the Commission to include in its report to the MCE draft Rules that would implement the enhanced constraint management arrangements proposed in the report. To the extent appropriate, the Commission will include in its recommendations and associated draft Rules a recommendation on whether the funding mechanism provided in this Rule should be continued, varied, or terminated.

6.1.5 Information Rules for managing congestion

A number of incremental changes could potentially be made to the Rules surrounding information provision in the NEM in order to assist participants in managing the trading risks associated with congestion.

There may be scope to make changes to the information available to market participants through NEMMCO's Market Management Systems. NEMMCO could publish information on mis-pricing. This information could:

- be either in the form of published nodal prices or differences between the RRP and nodal prices;
- identify whether the constraint that caused the mis-pricing was an outage constraint or a system normal constraint; and
- identify the network element or cut-set on which the limitation arose.

The Commission has already held discussions with NEMMCO on these possibilities and plans to investigate them further. The Commission also welcomes comments from stakeholders on other similar options. For example, the Commission wishes to understand whether any changes could be made to the PASA or pre-dispatch processes that would assist participants to manage trading risks. Stakeholders putting forward suggestions in these areas should comment on any confidentiality or competition issues that may arise.

[75] The AEMC 2006, *Negative Inter-Regional Settlements Residue*, Final Rule Determination, 30 March 2006, Sydney, and related submissions are available on the website at: http://www.aemc.gov.au/electricity.php?r=20051214.195359.

6.2 Rules for influencing the level of congestion

A number of options are available for changing the Rules in ways that are likely to indirectly assist participants to manage the trading risks of congestion by reducing the occurrence of congestion.

6.2.1 Investment and operation Rules

As noted above in Chapter 5, one means of reducing the occurrence of congestion is by increasing the actual or effective transfer capability of the network. Chapter 5 highlighted that the Commission has already undertaken substantial work in this area as part of its review of transmission.

The recent changes to the transmission revenue and pricing provisions in the Rules have clarified the ability of TNSPs to pass-through the cost of network support services to customers. This should promote the implementation of non-network alternatives where these are either the most efficient option or least-cost means of addressing reliability requirements. For these reasons, the Commission does not presently intend to commence a work program examining further changes to the Rules concerning transmission revenue-setting.

The Commission's transmission review also required the AER to put in place sharper incentives for TNSPs to undertake transmission outages at appropriate times. As highlighted by the AER in its congestion measurement publications, much of the financial cost and risk of congestion is associated with "last minute" changes in scheduled maintenance by TNSPs.[76] Improved incentives for TNSPs to notify market participants of changes to TNSPs' scheduled maintenance could facilitate improved risk management by market participants. As noted above, the AER is presently looking to modify its service target performance incentive scheme to take account of "market impacts". Therefore, at this stage, the Commission has no intention of amending the new service target performance incentive provisions in the Rules.

Similarly, the Commission understands that most Jurisdictional Planning Bodies (JPBs) tend not to use the market benefits limb of the Regulatory Test to justify network augmentations,[77] and there is a perceived reluctance to use the competition benefits component of that limb. If this is the case, it may be due to potential controversy and dispute over the market modelling work required to underpin the market (or competition) benefits assessment and of the assumptions inherent in that type of modelling work. There may be merit in the AER being empowered (or required) to publish a package of "safe harbour" guidelines for any such modelling work. For example, the AER could endorse a particular discount rate, demand

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[76] Australian Energy Regulator, *Indicators of the market impact of transmission congestion, Decision*, 9 June 2006, pp.6-7. See also AER reports on the indicators of the market impact of congestion more generally.

[77] VENCorp is the notable exception, carrying out all its valuations under the market benefits limb of the Regulatory Test. The Commission wrote to JPBs (who are usually TNSPs) in late 2006 seeking to understand the proportion of Regulatory Test evaluations that were carried out under each limb of the Test.

forecasts (possibly linked to SOO/ANTS), scenarios for modelling or process for identifying alternatives (such as some form of consultation). It may be possible to go beyond safe harbour provisions by introducing a requirement for all assessments of network augmentation proposals to include the standard SOO/ANTS scenarios. Such a requirement would ensure a degree of consistency in assessments and minimise any tendency for proponents to engage in obfuscation of the case for augmentation (or not).

However, as with TNSP incentives, the Commission recently made a Rule providing principles for the making of the Regulatory Test, including for the making of guidelines on the operation and application of the test (see clause 5.6.5A of the Rules). The Rule requires the AER to make a revised Test and guidelines by 31 December 2007. The Commission does not intend to contemplate further changes to the principles or their application prior to that time.

6.2.2 Information Rules for reducing congestion

Both NEMMCO and the TNSPs could be required to provide additional information on historical and potential levels of congestion in order to help promote efficient investment and potentially reduce the future extent of congestion. This could reduce the future trading risks associated with congestion. The Commission plans to institute a work programme in this area and seeks comments from stakeholders on the views and ideas outlined below.

In addition to publishing information to assist participants to manage the trading risks associated with congestion, there may also be scope for NEMMCO to publish more information (as against data) in relation to historical congestion. This could provide investors and risk managers with a stronger basis for forming views on trends in congestion, and hence, improve their locational and timing decisions. This may help in reducing congestion and trading risks in the longer term.

For example, NEMMCO could expand the SOO to include the tracking of trends in mis-pricing for connection points, or tracking of trends in the frequency and duration of mis-pricing across connection points. This information could be of use to investors as well as the AER, which could use the information to better measure and incentivise TNSP service performance. The Commission seeks stakeholder views on this idea.

There may also be potential for TNSPs' APRs to be made more accessible, so that information on the projected future level, timing and location of congestion can be better understood by those seeking to manage trading risks in the longer term. While transmission design and operations are specialised and technical areas – and prudent market participants and potential investors will undertake their own analysis of the risks arising from potential network congestion – additional information in the APRs could assist in this process. For example, information could be provided on:

- existing network transfer capability under "system normal" conditions – this would ideally be done against a metric that is common across the TNSPs;

- annual network capability duration curves for transmission cut-sets between ANTS zones. Such a metric could show the proportion of time that the network capability was close to its design capacity and also reflect incremental changes over time in the network capability arising for TNSP operations that increase the transfer capability of the existing network (e.g. through an increased use of Network Support and Control Services (NSCS); and

- the potential increase in network capacity when NSCS are enabled/dispatched both for reliability and market benefit reasons.

The Commission also considers that APRs could potentially be enhanced to include information on connection point to load centre transfer capability. Some generation investors (see Delta Electricity submission[78]) have claimed that there is a lack of information identifying:

- the network locations that can accept further generation injection without exacerbating congestion, and the amount of new generation that can be accommodated at those locations; and

- the cost of network augmentation to relieve any congestion caused if generation is injected above those levels.

Making information of this type available on a routine (e.g. annual) basis could assist generation investors, who currently have no means other than engagement of consultancy support for network modelling. If such information were published, it could help prospective investors create a shortlist of network locations with which they could approach TNSPs to discuss potential connection applications.

Modelling to yield information of this type is likely to be complex and possibly contentious, particularly while the operational and investment incentives of TNSPs do not focus strongly on network capability. Therefore, this kind of change lies at the far end of what could be considered an incremental change to the existing information arrangements. The Commission is considering whether to explore these issues further in a work programme and would welcome the views of stakeholders, including TNSPs, on both the likely usefulness of this information as well as the practical difficulties and costs of its provision.

The Commission would also welcome stakeholder views on what additional information could be provided (most likely on a user-pays basis) to support investment modelling analysis. For example, the Commission understands that load flow data sets (transmission line static data) and constraint sets are already available. Connection point demand data is understood to not be publicly available, leaving modellers to estimate this for themselves. The appropriateness of keeping connection point demand data confidential may be worthy of review, together with the overall form and availability of modelling data for investors.

78 Delta Electricity, Submission to Congestion Management Review Issues Paper, 13 April 2006.

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7 Options for fundamental changes to the congestion management framework

This Chapter discusses potential more *fundamental* changes to the existing market arrangements for congestion management. The same distinction is used as in the previous Chapters between options that:

- directly assist in the management of physical and/or financial risks associated with congestion; and
- influence the occurrence, duration or frequency of congestion, which may indirectly affect the physical and financial trading risks associated with congestion.

As noted in the discussion of the Commission's approach and in the previous Chapter, the intended focus of the CMR is on options for assisting directly in the management of trading risks arising from congestion.

As with the options for incremental changes discussed in the previous Chapter, for each option or topic, this Chapter explains:

- whether the Commission intends to investigate further the option or topic; and
- if so, the types of issues that the Commission will be investigating – for example:
  - whether an option is self-funding or not;
  - the technical feasibility of implementing the option on a localised basis; and
  - whether allocative or distributional decisions need to be made in order to implement the option.

7.1 Rules for the direct management of trading risk

7.1.1 Dispatch Rules

The Commission does not intend to consider fundamental changes to the Rules for dispatch on a NEM-wide basis. However, options for removing or changing NEMMCO intervention in dispatch may be worth considering (see Intervention Rules in Chapter 7.1.4 below).

7.1.2 Pricing Rules

7.1.2.1 Limited forms of nodal pricing

The NEM currently has six pricing regions. At each RRN, the price is set equal to the marginal cost of electricity *at that node*, based on the bids and offers made by participants. The RRP applies for spot market settlement throughout the relevant region, even if losses and constraints mean that the marginal cost of electricity at other nodes in the region diverge substantially from the RRP. As noted above, this can lead to certain generators being constrained-on or constrained-off, with potentially detrimental implications for bidding behaviour and the economic efficiency of dispatch.

The NEM therefore represents a limited form of nodal pricing, because only certain nodes are given an individual price that reflects local demand and supply conditions and the impact of network congestion. One way of managing congestion is to increase the number of nodes at which the price is set equal to the local marginal cost of supply. As more nodes are given an individual price, congestion is more likely to be reflected in spot price differentials. As noted previously in Chapter 4.3, this is likely to have a range of costs and benefits.

An increase in the number of nodes that are priced translates into an increase in the number of NEM regions. At the extreme, there is full nodal pricing.

The jurisdictions have made clear through the MCE that they do not believe that the benefits of full nodal pricing would outweigh the costs. The Commission also believes that full nodal pricing is beyond the scope of the CMR. As noted earlier, the ToR requests the Commission to consider the implementation of congestion management mechanisms to apply to specific instances of material congestion, *prior to* consideration of regional boundary change. This suggests that only interim congestion management mechanisms that apply on a particular set of binding constraints or cutset are within the scope of the Review. A move to full nodal pricing would be beyond the scope of the ToR by:

- applying to all congestion even when it is not material; and
- effectively pre-empting and obviating the consideration of regional boundary change as an ultimate solution to material and persistent congestion.

For these reasons, the Commission has no plans to investigate full nodal pricing any further.

A less radical alternative to full nodal pricing but more fundamental than incremental changes to regional boundaries is the adoption of generator nodal pricing. This is an arrangement where individual prices apply to each generator node but not to bulk supply (i.e. load) nodes. The Commission considers that this option would not be precluded by the MCE's position on full nodal pricing. However, as with full nodal pricing, the Commission believes this is beyond the scope of the Review, which is intended to address trading risks associated with the emergence of specific instances of material congestion. Consequently, the Commission intends to consider only localised forms of generator nodal pricing, where one or a "small" number of material constraints are involved. However, clearly the literature and experience on both full nodal pricing and generator nodal pricing would usefully inform this evaluation.

In this context, the Commission notes that from a dispatch perspective, it is only where the resource cost of a generator lies between the generator's nodal price and the RRP is there a risk of distorted bidding behaviour due to lack of pricing granularity. Where the resource cost of a generator lies *below* both the generator's nodal price and the RRP, the generator will wish to (and will) be dispatched if it offers its capacity at resource cost. Alternatively, where the resource cost of a generator lies *above* both the generator's nodal price and the RRP, the generator will not wish to (and will not be) dispatched if it offers its capacity at its resource cost. Even if generator bidding is distorted by mis-pricing, and this influences dispatch, the actual increase in resource costs may not be great.

Under a localised form of generator nodal pricing, consumers would either pay:

- the RRP, which would generate a settlement surplus if it was higher than the average nodal price at generators' connection points; or

- a volume-weighted averaged regional price such that no settlement surplus (beyond losses) was produced.

The key concern with even limited generator nodal pricing would again be the need for basis risk management instruments. CSCs or FTRs (see below under basis risk management) could be considered for this purpose.

The Commission intends to further investigate the implications of limited generator nodal pricing for interim application in limited areas where congestion is material.

7.1.2.2 Constraint Support Pricing (CSP)

CSP is a mechanism provides a localised electricity price for a generator without altering the price paid by loads.[79] The CSP mechanism is specifically designed to provide sharper locational pricing signals in the presence of congestion than would otherwise be the case in the NEM's zonally settled market. The general CSP mechanism is designed for the NEM's regional pricing design and provides a means of having constrained-on and constrained–off payments that are funded out of the existing settlement residues, rather than requiring either a separate uplift charge on energy sales or funding via regulated transmission charges. A CSP (combined with a constraint support contract (CSC) – discussed below under basis risk management) has been used at Tumut since 1 October 2005 to provide Tumut power station with a localised price at times of constraint between Murray and Tumut under the existing Snowy regional boundary structure.

The partial trial of CSP/CSC at Tumut was designed to ensure Snowy Hydro had incentives to offer its Tumut generation capacity at times of high NSW demand when constraints between Murray and Tumut meant that the Snowy RRP was low. Without the CSP, Snowy Hydro may have had incentives to bid Tumut generation as unavailable or only offer to supply at $10,000/MWh. This may have led to inefficient dispatch, because more costly NSW or Queensland plant may have been dispatched in place of Tumut. Effectively, the Tumut CSP is a form of constrained-on payment in which the source of funding for the payment comes from the IRSRs attributed to

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79 CRA, *NEM Regional Boundary Issues: Theoretical Framework*, *Final Report*, submitted to the MCE, Melbourne, 14 September 2004; and CRA, *NEM Regional Boundary Issues: Modelling Report, Final Report*, submitted to the MCE, Melbourne, 16 September 2004.

the Snowy-NSW interconnector. It should be note that the output of Tumut generation adds to the value of these residues.

At the same time, CSPs are a relatively new innovation and are not included in the body of the Chapter 3 market dispatch and settlement Rules. Moreover, there is nothing inherent in the CSP mechanism that prevents them being used to *reduce* the price at which a generator is settled.

In fact, under a CSP mechanism, those generators who exacerbate the level of congestion (and who would have a local price below the RRP – i.e. be constrained-off) would be required to make a congestion-related payment to NEMMCO. In the absence of a CSC, this payment would effectively reduce the settlement price they receive on all their output from the RRP to their nodal price. If they had CSC (discussed below), which provides access to settlements at the RRP, only a portion of their output (rather than all) would be paid the lower nodal price, with the remainder being settled at the RRP, in accordance with their allocation of CSCs. For this reason, the CSP concept is broader than simply a tool for the facilitation of constrained-on payments (discussed in Chapter 6 on incremental change); it also incorporates constrained-off payments by some generators. Therefore, the Commission believes that notwithstanding their use in the trial at Tumut, CSPs belong in the category of fundamental change to the existing market arrangements, similar to a limited form of generator nodal pricing.

The Commission intends to further examine CSPs as part of a work program on more refined pricing options in which it will compare and contrast the alternative models. However, as with its consideration of generator nodal pricing, the Commission will only consider localised applications of CSPs. On this basis, the Commission believes that a full rollout of CSPs (with or without CSCs), as proposed by the LATIN Group[80], is outside the scope of the ToR. A full rollout would not, almost by definition, be a response to the emergence of identified instances of material congestion.

7.1.2.3 Deep connection charges

A further option for providing locational signals in respect of actual or potential congestion is through pricing for network services. The new Chapter 6A of the Rules already provides for locational TUoS prices charged to load on the basis of peak demand. This is in recognition of the fact that the transmission network is developed to serve peak loading conditions. Such conditions are also those most likely to create congestion.

The Rules maintain a “shallow” connection charging approach for new generation. This means that generators only need to pay for the costs of their immediate connection to the transmission network and are not required to contribute to the costs of downstream augmentations from which they may benefit, so long as those augmentations satisfy the Regulatory Test. At the same time, generators may

80 International Power, Loy Yang Marketing Management Co., NRG Flinders, TRUenergy, AGL Hydro, Submission on CMR Issues Paper April 2006

voluntarily pay for the costs of downstream augmentations. Under a "deep" connection approach, generators are required to pay downstream costs. Where this occurs, generators then tend to receive financial rights such as FTRs (see below) entitling them to a share of the value of those lines at times of congestion.

In a supplementary submission to the CMR, Delta Electricity suggested a variation of a deep connection approach. Delta proposed that new generators should pay the cost of downstream augmentations if their investment location did not align with the least-cost transmission plan:

> "Where congestion is likely to be created by the new generator, the TNSP determines the additional cost of any long term network augmentation (LRMC) required to avoid congestion occurring. If the new generator locates where there is ample transmission access or where the network is likely to be augmented as part of the least cost plan then the LRMC would be zero. If however, the generator, for whatever reason, determines to locate where congestion does result and the LRMC is positive (and above a tolerance level), then the generator would be exposed to this cost."[81]

The Commission came to the view in its Transmission Pricing Determination[82] that a move to a deep connection regime was not warranted for several reasons. However, the Commission understands that participants (particularly existing generators) are concerned about the existing locational incentives facing new generation investors. Under the existing Rules for dispatch and settlement, a new generator can locate in a congested area and, where constraints bind, bid down to -$1,000/MWh to be dispatched. Due to the "tie-breaking rule" applied in NEMDE under such circumstances (see Chapter 4.2.1), such generators can access the RRP on a proportion of their output even though the nodal shadow price at that location is lower. While existing generators face these incentives, their capital costs are largely sunk. New generators, however, may be locating in inappropriate areas due to the mis-pricing they face. The Delta Electricity proposal effectively imposes a cost of new generators seeking to locate in congested areas, while quarantining existing generators from inefficient locational decisions. The Commission's current thinking is that this could potentially lead to inefficient network investment.

As noted in Chapter 6, the Commission is of the view that any form of access rights (whether physical or financial) should be dealt with transparently. Therefore, while the Commission understands the rationale for proposals such as Delta Electricity's, it does not intend to consider that proposal further in the CMR. The Commission will consider financial access issues in the context of the development and implementation of risk management instruments.

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81 Delta Electricity, Supplementary submission, Congestion Management Review, 9 November 2006, p.9.

82 AEMC 2006, *Pricing of Prescribed Transmission Services*, Final Rule Determination, pp.21-22.

7.1.3 Risk management Rules

As noted in Chapter 6, the IRSR instrument could be modified to improve its usefulness as a tool for managing basis risk. This Chapter discusses options for more fundamental changes relating to both IRSRs as well as other potential basis risk management mechanisms in the NEM. Such instruments would need to be considered for managing the basis risk arising from an increase in the pricing granularity of NEM settlements.

7.1.3.1 Changes to IRSRs

As noted above, IRSR units are a form of FTR. An FTR is a financial instrument that entitles the holder to receive compensation for transmission congestion costs that arise when the transmission grid is congested.

There may be scope to improve the NEM's existing IRSR units as a means of managing basis risk by exploring ways of incorporating some more of the characteristics of nodally based FTRs which have been used in North America. This approach was supported in submissions to the Issues Paper by Ergon Energy and John Hoddinott, who both consider other types of FTRs a firmer product than existing IRSR units.[83]

In this context, a number of more fundamental changes could be made to the IRSR instrument.

The first is changing the definition of IRSR units so that they are effective in the presence of looped (rather than radial) regions and loop flows. The existence of physical loops on a meshed network—regardless of whether they are fully contained within a region (such as currently occurs in NSW & Queensland)—has the potential to affect dispatch across the entire network in the event of the limit on a segment on that loop becoming constrained. The possibilities include:

1. When regional pricing & settlements overlays the (nodal) dispatch, generators will have incentives to bid in ways that align their output level with the RRP. This mis-pricing can contribute to counter-price flows that are not economically efficient (noting that some counter price flows are) and which undermine the value of IRSR units as a hedging instrument.

2. When physical loops occur across region boundaries (e.g. Snowy region) this problem takes on a range of more difficult issues, some of which are discussed in the Commission's Determination on the Southern Generators' Rule change proposal.[84]

3. Finally, when a physical loop on the AC network occurs, (e.g. if SNI were built) it might not be possible to maintain a radial regional pricing structure. There

[83] Ergon Energy, Submission on Issues Paper, Congestion Management Review, May 2006, p.3; John Hoddinott, Submission on Issues Paper, Congestion Management Review, 13 April 2006, p.2, 4-6.

[84] AEMC 2006, *Management of negative settlement residues in the Snowy Region*, Final Rule Determination, 14 September 2006, Sydney.

would have to be a looped pricing structure. Under a looped regional structure (e.g. a three node VIC-SA-NSW triangle), at least one interconnector would accrue large, negative residues, which would be difficult to fund given the existing design of IRSR units and means of recovering negative residues. That is, IRSR units could become a very ineffective means of managing basis risk. As the network evolves to become more highly meshed, and noting that meshed networks deliver greater reliability of supply, there is likely to be more loops within and across the existing regions.

Second, funding negative residues on one directional interconnector with the positive residues on another directional interconnector when the total residues across the two interconnectors are related to a common constraint, or set of constraints. The Commission found some dispatch efficiency and inter-regional trading risk improvements could arise from such an approach when it made the Southern Generators' determination. There may be potential for such an approach to be used elsewhere in similar circumstances. [85]

7.1.3.2 Constraint Support Contracts (CSC)

Another option for more fundamentally changing the instruments for basis risk management in the NEM is the use of CSCs. The implementation of CSCs can affect the payments to IRSR unit holders and the degree to which a generator subject to a CSP is able to access the congestion rents implicit in the RRP.

As noted above, a CSC has been used as part of the arrangements for Tumut generation under the current derogation. The CSC provides payments to Snowy Hydro in respect of its Tumut power station such that, at times of southward flows and constraints between Murray to Tumut, (only) 550 MW of Tumut output is settled at the Snowy RRN price. This partially offsets the CSP for Tumut (in which Tumut output receives its nodal price at times of Murray-Tumut constraint). As with the Tumut CSP, payments made under the CSC are funded by the residues accruing on the NSW-Snowy interconnector.

Like IRSR units, a CSC is a form of FTR that entitles its owner to a share of the congestion rentals arising in the NEM. It is not a physical right in that it does not provide the holder with a preferential right of access to the use of the network for the transportation of power. However, by providing a payment stream based on the difference between a nodal price and a RRP, it could be used to help a participant manage basis risk. For example, combined with CSPs, CSCs would allow generators to enter contracts with loads paying the RRP with less need to worry about constraints between themselves and the RRN.

The key issue with CSCs, as well as other forms of FTRs, is the question of working out how they should be allocated. The literature on FTRs could be useful in this context. One approach is to auction off CSCs, as IRSR units are currently auctioned. It should be noted that not all CSCs would have a positive value, so not all CSCs

[85] Under full nodal pricing, the sum of all residues is always positive. This means that there is sufficient positive residues across the network to cover any negative residues.

could be sold in this manner.[86] This suggests that there may be a funding shortfall that would need to be somehow recovered. Further, because some generators would be required to pay for something they now get for free – access to the RRP on their dispatched output – auctioning could result in a wealth transfer from these generators to loads, other generators, or IRSR unit holders.

Another approach, suggested by the LATIN Group, is for incumbent generators to receive CSCs according to a methodology based on historical dispatch output levels, (under peak demand and network system normal conditions).[87] As these generators are already located where they are, this approach would not encourage (new) generators to locate in constrained parts of the grid. However, it would provide a benefit to incumbent generators without offering any efficiency improvements over auctioning.

Any allocation mechanism for CSCs is likely to be controversial, regardless of how straightforward the methodology appears to be in theory. The Commission would be particularly concerned to ensure that whatever means of allocation is applied does not lead to the creation of barriers to entry to new generation investment. This is important in the context of the likely need for substantial investment in new capacity across the NEM in the medium term. The Commission will give attention to this issue in its intended work program on risk management instruments.

7.1.3.3 Constraint-Based Residues

Another option similar to CSCs is the creation of constraint-based residues (CBRs), as described in a paper by Dr Darryl Biggar.[88] Biggar noted that transmission congestion gives rise to what is commonly referred to as “congestion rents” or “settlement residues” or the “merchandising surplus”. These residues arise from the divergences between the nodal prices around the network when a constraint is binding. Under the current NEM design, these residues are distributed between generators and interconnector flows. However, different ways of dividing up these residues are possible and may allow more useful hedging instruments to be developed. Importantly, neither CBRs nor CSCs provide holders with a mechanism for hedging against the risk of congestion or price separation caused by transmission line outages or deratings, unless some party outside NEMMCO is exposed to the risk of them occurring. This issue is put to one side in the discussion of CBRs below.

Under the existing approach to allocating congestion residues, generators located within a particular region are entitled to receive the (loss-adjusted) RRP on their dispatched output, despite the fact that constraints may place them electrically in a separate region. Meanwhile, generators located in another region may purchase IRSRs that provide them with a share of the residues arising on interconnector flows between the relevant regions. However, as noted in Chapter 2, where a constraint

[86] CRA, *NEM – Transmission Region Boundary Structure*, Final Report submitted to the MCE, Melbourne, September 2004.

[87] LATIN Group, Submission on Issues Paper, Congestion Management Review, April 2006, p. 12-15.

[88] Biggar, D., *Solving the Pricing and Hedging Problems in the NEM Using “Constraint-Based Residues”*, 25 October 2006.

that is affected by both inter- and intra-regional flows binds, inter-regional price separation may occur even though interconnector flows are below their notional limits. This implies that IRSR unit holders may not obtain a perfect hedge against inter-regional price differentials.

Under the CBR approach, the residues arising from a particular constraint are gathered together in one fund. Since, as Biggar shows, these funds are normally positive, shares or units in this fund can be allocated or auctioned to participants. Participants seeking a financially firm hedge against the binding of a particular constraint then need only acquire a pre-determined proportion of the residues attributable to that constraint. The proportion required depends on the coefficient on the generator in the relevant constraint equation. This approach differs from the current IRSR-based approach where the residues arising from a particular constraint are typically shared between IRSRs and local generators.

Dr. Biggar noted that there are similarities between CBRs and CSCs. Both can be applied flexibly to one or more constraints at a time. However, he contends that the CBR approach has one key advantage over CSCs. He suggested that CBRs would always be revenue neutral because only the residues arising due to a particular constraint are returned to unit holders. However, if an attempt is made to deliver "firm" IRSR units, CSCs may not be revenue neutral in some circumstances because they may effectively lead to over- or under-allocation of the residues arising from a particular constraint. Finally, since CSC rights can have a negative value, revenue neutrality may require some participants to accept them and therefore to be made significantly worse off than before the imposition of the CSCs.

The Commission notes the CBR proposal and Biggar's concerns about CSCs and intends to commence a work program to understand better these issues. In particular, the Commission is keen to examine:

- the practicability of developing CBRs to deal with particular constraints and, in particular, the extent to which each constraint is firm subject to outages or deratings;
- whether the CBR approach is guaranteed to be revenue-neutral;
- whether CBRs can be adopted on a geographically-limited basis or whether they can only feasibly be adopted NEM-wide; and
- how CBRs could and should be allocated or otherwise made available.

As with CSCs, the Commission intends to ensure that whatever means of allocation is applied does not lead to the creation of barriers to entry to new generation investment. This could have a highly detrimental effect on the NEM given the likely need for new capacity in the medium term.

The Commission notes that the adoption of CBRs could require generator nodal pricing to operate, or at least generator nodal pricing with respect to those generators affecting the relevant constraint(s). Therefore, consideration of CBRs would need to be undertaken alongside the Commission's analysis of limited generator nodal pricing.

7.1.4 Intervention Rules

Under the current NEM Rules discussed above, generators and scheduled load are dispatched on the basis of their offers or bids to meet the regional demand at the lowest cost (based on their bids and offers), and are settled at the RRP.

As discussed in Chapter 2, this can provide certain generators (those that are either constrained-on or constrained-off) with incentives to bid in ways that do not reflect their resource costs. In some cases, this can cause counter-price flows to occur on interconnectors between regions. Under Part 8 of Chapter 8A of the Rules, NEMMCO is currently obliged to institute constraints to prevent the counter-price flows from continuing (such as by "clamping"). As noted in the Commission's Determination on the Southern Generators Rule, clamping and similar interventions can reduce dispatch efficiency.[89]

NEMMCO's current threshold for intervention is when negative settlement residues are forecast to reach $6,000 per event.[90] Pursuant to a Rule change in early 2006 (discussed above in Chapter 6.1.4) NEMMCO can recover the accrued negative settlement residues from future IRSR auction proceeds.[91] This reduces its financial risk emanating from counter-price flows. NEMMCO recently conducted a consultation on raising the intervention threshold from $6,000 to $100,000, but this was rejected on the basis of stakeholder submissions.[92]

In this context, one option for fundamental change could be for the intervention obligation in Part 8 of Chapter 8A of the Rules to be removed. In its Statement on Transmission, the MCE supported the interim use of arrangements enabling NEMMCO to manage the occurrence of counter-price flows.[93] However, the Statement was made in May 2005 and it noted that the intervention provisions had been extended to December 2005. Given that the recommendations of the CMR are unlikely to be implemented before 2008, the Commission considers that options involving the removal of these interventions are within the scope of the Review.

Abolishing clamping would remove a form of intervention that is, of its nature, unpredictable and has profound impacts on network flows, dispatch and price outcomes. Such a change would be consistent with good regulatory practice, as noted in the Commission's Southern Generators Rule Determination. As NEMMCO could recover negative settlement residues from the market, this change should not pose any operational problems for NEMMCO. It may also improve the efficiency of dispatch, although this is not assured.

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89 AEMC 2006, *Management of Negative Settlement Residues in the Snowy Region*, Final Rule Determination, Appendix A, pp. A31-A33.

90 NEMMCO uses "reasonable endeavours" to apply constraints to prevent the accumulation, provided system security is not compromised. See NEMMCO, *Operating Procedure: Dispatch*, Document Number: SO_OP3705, Version 45, 27 February 2007, p.32.

91 AEMC 2006, *Negative Inter-Regional Settlements Residue*, Final Rule Determination.

92 NEMMCO, "*Review of the Trigger Level for Management of Negative Settlement Residues - Final Determination Report*", 27 Oct 2006, filename: 570-0002, available: http://www.nemmco.com.au/dispatchandpricing/570-0001.htm.

93 MCE, *Statement on NEM Electricity Transmission*, May 2005, p.5.

A disadvantage with removing NEMMCO intervention to address counter-price flows is that in some cases, the firmness of the relevant IRSR units may be reduced. Further, in some circumstances, it could accentuate constrained-off generators' incentives and ability to bid below resource cost in order to be dispatched. This was not a great concern in the Southern Generators Determination because Murray generation received its own nodal price (the Snowy RRP). However, in other areas of the network, removing intervention could heighten the incentives of constrained-off generators to bid -$1,000/MWh. The Commission therefore welcomes comments on this option.

In cases where the removal of clamping was likely to be detrimental, alternatives could be available that overcome some of the unpredictability of clamping while enhancing some of its benefits. For example, where constraints are affected by both inter-regional flows and local generation output, inter-regional flows could be given priority to the available transmission capacity – not by changing the constraint formulation but by adding new (fully optimised) constraints to the NEMDE. This could have a number of benefits.

First, giving priority to interconnector flows means that the firmness of the relevant IRSR units would be maximised up to the physical limits of the network. Subject to network loops (such as in the present Snowy Region), counter-price flows would be far less likely to occur because intra-regional generators would not be able to "crowd out" interconnector flows. This should enhance the ability of participants to manage inter-regional basis risk. Electricity would be more likely to flow from low-priced to high-priced regions as intended within the market design.

Second, locational signals to new generators may be improved. Generators would not be able to locate in a remote part of a region and (by bidding below cost) be dispatched and receive a RRP that is much higher than their nodal shadow price.

Third, treating interconnector flows preferentially would provide intra-regional constrained-off generators with stronger incentives to either propose regional boundary change or transmission investment to address those constraints. For example, a low-cost generator located in a remote part of a region would have incentives to propose the creation of a new region to prevent interconnector flows from receiving preferential treatment.

On the other hand, as with clamping, such an intervention would have major impacts on dispatch outcomes, interconnector flows and prices. For example, it may increase dispatch risk for intra-regional generators that are sharing transmission capacity with interconnectors. Further, it involves explicit discrimination against intra-regional generation in favour of interconnector flows. This may be contrary to good regulatory practice. However, as an alternative to clamping, this option may be worth examining. The Commission seeks stakeholder views on the relative merits of this approach compared to simply retaining or eliminating clamping.

7.2 Factors influencing the level of congestion

The sections above discuss potential reforms to market arrangements for a given level of congestion. The Review must also consider, as stipulated in the Terms of Reference, factors affecting the *level* of congestion, including how they might interact with the potential measures discussed above. There are two main factors influencing the level of congestion at any given time for any given geographic pattern of generation and load: first, the physical network of transmission assets; second, the manner in which those assets are operated, including how TNSPs and/or NEMMCO contract for network support and ancillary services.

7.2.1 Transmission investment

The regulatory framework governing transmission investment has undergone extensive review in the recent past, culminating in the completion of the review of Economic Regulation of Transmission Services and the subsequent making of Chapter 6A of the Rules. This framework should be given time to operate before any further process of review or reform. The Commission does not therefore intend to consider the case for changes to the regulatory regime for transmission investment as part of this Review.

7.2.2 Transmission operation

The Issues Paper sought views on how Network Support Agreements (NSAs) and Network Support and Control Services (NSCS) contracts might be used more actively to address congestion issues. These contracts are used for wider operational reasons, including to address reliability and security issues. A theme emerging from Submissions to the Issues Paper in this regard was the issue of transparency and clarity in respect of how these contracts might be used in the context of congestion management, including who is accountable. Currently, both NEMMCO and TNSPs are involved in the procurement of these services.

Macquarie Generation stated that the current Rules lacked clarity over NEMMCO's responsibilities regarding system security and system reliability.[94] NEMMCO expressed that under the current arrangements there is overlap in the role it and TNSPs have to operate a reliable network, particularly regarding the procurement of reactive power.[95] Transend agreed with NEMMCO, stating that the current arrangement required clarification of NEMMCO's role to procure Network Support and Control Service .[96] The NGF raised a specific problem with network support agreements NSA, stating that the cost of NSA arrangements was not transparent. It said the approach worked for constrained-on payments but not for constrained-off, and that TNSPs lacked incentives to purchase or pay for the services.[97] A real risk for consumers, the MEU identified, came from the lack of clarity in the Rules to permit resolution of constraints when they arose.[98]

The current framework permits (or requires) the following:

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[94] Macquarie Generation, Submission on Issues Paper, Congestion Management Review, 17 April 2006, p. 3.

[95] NEMMCO, Submission on Issues Paper, Congestion Management Review, 13 April 2006, p. 17.

[96] Transend, Submission on Issues Paper, Congestion Management Review, 2 May 2006, p. 2.

[97] NGF, Submission on Issues Paper, Congestion Management Review, 13 April 2007, p. 14-15.

[98] MEU, Submission on Issues Paper, Congestion Management Review, April 2006, p. 40.

- when NSPs undertake a network augmentation or procure/deliver NSCS with "reliability" benefits primarily in mind, those activities relieve congestion and deliver market benefits;

- NSPs can undertake network augmentation or procure/deliver NSCS with the specific purpose of delivering market benefits – as assessed by application of the regulatory test; and

- NEMMCO has a responsibility under clause 3.11.4(b)(2) of the Rules, to develop and publish a procedure for determining the quantities of each kind of NSCS required for NEMMCOs:

> "**where practicable** to enhance network transfer capability whilst still maintaining a secure operating state when, **in NEMMCO's reasonable opinion**, the resultant **expected** increase in non market ancillary service costs will not exceed the resultant **expected** increase in benefits of trade from the spot market." [Emphasis added.]

However, NEMMCO must also act in accordance with its responsibilities under the Rules, which might in some instances require it assuming primary responsibility. In practice, NEMMCO currently limits itself to:

- not procuring services for the express purpose of increasing benefits of trade from the spot market; but

- deploying, where practicable, services procured for security and reliability purposes where those services can increase the benefits of inter-regional trade from the spot market as assessed in pre-dispatch time frames.

The approach adopted by NEMMCO might, in practice, result in TNSPs taking on primary responsibility for the design of network support services to address congestion. Since network support services are both a necessary complement to network assets, and also a partial substitute for them, there may be merit in ensuring that TNSPs have full control of their procurement to deliver a defined network service at minimum cost. The previous MSORC review[99] examined many of these issues and provides a useful starting point for examination of these issues.

Given the reforms to Chapter 6A of the Rules and to the Regulatory Test principles, and given the role of NSCS contracts in operational issues other than congestion management, the Commission currently considers the issue out of scope of the Review in terms of driving recommendations for further reforms to the Rules. The trigger NEMMCO uses to undertake an assessment of the value of deploying relevant services to relieve intra-regional congestion (and improve interconnector capability) is potential substantial price separation between regions as flagged in pre-dispatch processes. However, this mechanism is far from perfect. Furthermore, although situations may emerge whereby there is value to the market in relieving intra-regional congestion through strategic deployment of NSCS, the absence of

[99] Market and System Operation Review Committee, *System Security and System Operation Review, Report 1: System Operator Functions and Responsibilities*, March 2001.

intra-regional price separation has thus far prevented NEMMCO from developing a practical mechanism by which to signal the opportunity to deploy NSCS in this way.

Even though, NEMMCO limits its deployment of NSCS for the benefit of trade to the activity of managing interconnector capability, neither NEMMCO nor NSPs have been formally assigned an accountability for delivering interconnector capability. Responsibility for the interconnector capability envelope is shared between TNSPs and NEMMCO, but there is no common understanding in the market as to what that interconnector capability envelope looks like and, hence, what level of NSCS should be delivered.

Arguably, since MSORC, many of the policy matters of concern to the MCE have been resolved, with appropriate Rules developed by the Commission. These matters include the MCE position on fully optimised constraint formulation, reforms to Chapter 6, and reforms to the Regulatory Test Principles. The MCE has also provided policy direction on its preferred approach to and criteria for implementing region boundary changes. The CMR provides an opportunity for the ambiguities arising from clause 3.11.4(b)(2) to be resolved, with a range of options being presented to the MCE. These options could be presented in the context of a fully integrated Congestion Management Regime that builds on the significant progress made by the Commission and AER in progressing the transmission regulatory regime. The MCE could then provide a clear policy direction on governance arrangements for NSCS and, as part of its response to the CMR Final Report, provide Draft Rules to the AEMC that would be subject to further consultation.

However, the Commission currently views this stream of work as falling outside the ToR of the CMR. The Commission acknowledges that such options may well be worth further consideration, but considers they go beyond what could reasonably be addressed in the CMR. While the question of roles and responsibilities for NSCS contracts is clearly an important issue for the operation of the NEM, it would appear to involve issues wider in scope than the Congestion Management Review specified by the MCE. The Commission therefore believes that fundamental changes to TNSP roles and responsibilities would warrant a separate and more specific review.

Further, as noted above, the Commission has already provided for the implementation of a more powerful service target performance incentive scheme in its recent transmission Rule changes. The Commission awaits the outcomes of the AER's guidelines in relation to this scheme and until that work is completed is of the view that changes to the relevant Rules are not yet warranted.

The Commission would welcome submissions on this approach.

8 Packaging and sequencing of options

8.1 Packaging issues

In discussing the various options for change, the Commission noted that options involving greater pricing granularity to address mis-pricing problems could lead to participants facing increased basis risk. This basis risk can be managed in a number of ways. As discussed earlier, these include the purchase of financial insurance products or physical or financial agreements or transactions concerning plant located in other regions.

While the Rules do not preclude any of these activities, it is also likely to be beneficial for the settlement residues arising from the spot market to be used to provide instruments for managing basis risk. As IRSR units – though imperfect – already exist, the Commission would be reluctant to recommend significant changes to dispatch or pricing Rules without improving the tools available to hedge basis risk. Therefore, the Commission is of the view that options for greater pricing granularity ought to be considered jointly with options to provide firmer risk management instruments through the NEM spot pricing and settlement arrangements.

8.2 Sequencing issues

As noted in Chapter 2, the MCE ToR explicitly requires the Commission to consider the merits of a congestion management regime that would apply as an interim measure prior to any regional boundary change. The MCE Rule change request on the reform of regional boundaries also envisages a constraint management regime would apply to material congestion in the short term, with consideration of transmission investment and boundary change to follow.

As noted above, the implied basis of this approach is that persistent and material congestion ought to be dealt with by transmission investment or boundary change.

However, as has become apparent to the Commission, while regional boundary change may address the mis-pricing of generation and consequential inefficiencies, it may have other shortcomings. One shortcoming is that more regions need not always yield firm IRSRs for hedging basis risk nor even guarantee positive IRSRs for all interconnectors. At the same time, the Commission understands that certain other mechanisms, such as CSP/CSCs and CBRs may achieve some or all of these outcomes but at the cost of potentially greater complexity. This raises questions for the MCE about the end point of the congestion management framework, which may in turn affect the appropriate life of any interim congestion management mechanism.

In addition, the approach of the ToR and regional boundaries Rule change requests indicates that the implementation of a congestion management regime can be done at relatively short notice. While it is true that such regimes can be designed to exclude impacts of consumers, they still raise substantial issues for resolution by the relevant governance body.

These issues include:

- Which constraints and nodes are to be the subject of the constraint management regime;
- How should property rights to congestion residues be allocated in a way that does not create barriers to entry;
- What threshold should apply to the introduction of the mechanism;
- Should the mechanism be time-limited – there may be circumstances where no transmission investment occurs to alleviate the constraint yet a regional boundary change still fails to prove worthwhile; and
- Should there be an allowance to jump directly to a boundary change where this is the most efficient and transparent means of dealing with enduring congestion. Should many years of inefficiency be tolerated when it is apparent that it is not going to be economic to build out congestion for a long time and that any "temporary" congestion pricing mechanism is likely to be difficult to implement, and more complex/less transparent than a boundary change?

This suggests that the intended role and place of a congestion management regime (if any) may need rethinking. Arguably, such a regime could be both:

- more effective than regional boundary change in addressing both dispatch and risk management issues; and
- more complicated and controversial than regional boundary change (or generator nodal pricing) in addressing congestion.

The Commission will give these matters further consideration as it proceeds with the CMR and the reform of regional boundary Rule change request, and welcomes any new insights from stakeholders.

As for more general options for helping to address the physical and financial trading risks of congestion, a number of options are available. These include incremental changes such as enhancements to the SRA instruments or the provision of additional information on binding constraints and mis-pricing. More fundamental options could include a move to FTRs or changes to the current means of NEMMCO intervention at times of counter-price flows.

Finally, the Commission reiterates that it will seek to ensure that any recommendations for change to the existing market arrangements are proportionate to the materiality of the problem. The Commission will be guided on the materiality of congestion by its ongoing work program in this area.

9 Way forward

The Commission has clearly highlighted areas where it intends to maintain or commence work programmes to examine various options. In particular:

- more refined pricing approaches such as limited generator nodal pricing, CSPs, and constrained-on payments that do not involve funding using an uplift charge on energy transactions;

- improved basis risk management instruments, such as enhancements to the IRSR framework of varying degrees, FTRs, CSCs, and CBRs;

- the provision of additional information, particularly on the current level and implications of congestion; and

- a review of clamping and any intervention alternatives for the management of counter-price flows.

In general, the Commission does not intend to revisit matters that were addressed in the revenue of transmission regulatory arrangements or issues surrounding the delineation and allocation of TNSP and NEMMCO roles and responsibilities.

Importantly, the Commission's consideration of options will occur alongside its key work program examining the materiality of the level and implications of congestion. Information on the materiality of congestion will be compared with the Commission's work on the options to determine which options warrant recommending.

The Commission seeks stakeholder feedback as to whether these are the appropriate areas of attention for the CMR and if not, why this is the case.

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