



National Electricity Market Regional Structure: Notes for Industry Forum, 31 March 2004

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1. BACKGROUND

In December 2003, the MCE in its report to COAG on Energy Markets, adopted four principles to underpin electricity transmission policy in the NEM:

1. The transmission system fulfils three key roles – it provides a transportation service from generation source to load centre, facilitates competition, and ensures secure and reliable supply.
2. There is a central and ongoing role for the regulated provision of transmission, with some scope for competitive (market) provision.
3. Transmission investment decisions should be timely, transparent, predictable and nationally consistent, at the lowest sustainable cost.
4. The regulatory framework should maximise the economic value of transmission, including through the efficient removal of regional price differences in the operation of the NEM.

The MCE has agreed to a package of initiatives that included a recommendation that jurisdictional boundaries should be maintained for retail customer pricing. Further that a new and more transparent process (managed by the AEMC) is required to enable assessment of regional boundary changes for the wholesale market to facilitate investment and more efficient operation of the NEM while maintaining a secure power system.

The MCE has commissioned Charles River Associates (Asia Pacific) Pty Ltd (CRA) in conjunction with National Economics Consulting Group (NECG) and Alan Rattray of Co-Power, to conduct an independent economic study to develop the criteria and process for a new approach to establishing transmission region boundaries.

A number of other reviews by existing market authorities have considered aspects of the matter. This review by the MCE has been afforded the scope to examine matters beyond any single regulatory instrument or the authority of any single body that has of necessity constrained the earlier reviews and led to the jurisdictions requesting a moratorium on changes arising from them.

1.1. REVIEW & CONSULTATION PROCESS

Given the importance of regional boundaries for electricity market participants and the effect regional boundaries have on the design, efficiency, and pricing of the NEM, the MCE has sought to have an open consultation process. The consultation process includes an industry forum, meetings with interested parties, and consideration of submissions by interested parties on the draft and final reports of the consultant.

An industry forum is to be conducted to provide a means for the CRA team to be fully informed of the key issues of concern to stakeholders. This document provides background for the forum. It presents, at a relatively high level: the history of region boundary development, descriptions of the key alternative mechanisms that have been considered and a summary the key issues that are to be considered by the team in developing recommendations for the review, in particular.

- An overview of the status quo regarding region boundaries is presented in Section 2 — covering issues such as the design of the NEM, why region boundaries matter, the existing criteria for determining the location of regional boundaries, and the lack of change in regional boundaries since market start in December 1998;
- Section 3 summarises the history of region boundary and related constraint and settlement issues:
 - region boundaries;
 - the criteria used to determine region boundaries; and
 - the formulation of network constraints and, where relevant, ancillary services dispatch and SRAs.

In some cases, proposals put forward so far have been restricted by what is possible under the existing NEC or have been limited by factors outside of the Code;

- Section 4 outlines the role of the current review and in particular notes the policy boundary imposed by the MCE in the requirement that any new arrangement must provide for jurisdictional boundaries to be used for retail customer pricing;
- Section 5 scopes the range of possible alternatives to the existing NEM regional structure. Each model has potentially different implications for dispatch, reference pricing, participant pricing and hedging. These implications affect judgements of the relative merits of each model and offer insights into what needs to be addressed in considering any changes to the NEM's existing pricing model;

- Section 6 outlines evaluation and assessment issues; and
- Section 7 presents questions to be addressed at the forum.

2. STATUS QUO

2.1. NEM MARKET DESIGN

The NEM uses a regional pricing and dispatch structure, that was intended to approximate the locational pricing one would expect under nodal pricing. How good an approximation depends on how well the regional boundaries and loss factors reflect inter and intra-regional transmission capacity and system security constraints and thereby minimise any inconsistencies across the physical dispatch and regional reference prices. For example, within each region, a generator offering to supply at a given price should expect to be dispatched if the regional price was greater than its offer (bid) price. This is not possible where network constraints limit the dispatch of generators (or demand side resources, that on a pure price basis would be dispatched). This and similar deviations from the ideal are significant drivers for review of the boundaries.

A policy decision by the MCE recommending that jurisdictional boundaries should be maintained for retail customer pricing is a key initiative of this review.

The Code anticipated that regional boundaries would evolve over time, to reflect changing power system topology and congestion and in order to retain locational pricing signals that were reflective of costs of local supply.

2.2. CURRENT PRINCIPLES IN THE NEC FOR DETERMINING REGIONAL BOUNDARIES

The current principles for establishing and reviewing regional boundaries are set out in Clause 3.5 of the National Electricity Code (NEC). Six principles are stated, although the Code also acknowledges that it may be impossible to satisfy all of the criteria.

The existing criteria for determination of regions, as set out in Clause 3.5.1(b)(2) of the Code, are that:

- (i) *The boundary of a region will be closed and will enclose at least one significant load centre and/or generation centre.*
- (ii) *Where practicable significant generation and/or load centres separated by network constraints should be located in separate regions where those network constraints are likely to influence the optimal dispatch of generation and/or scheduled load in the order of 50 hours or more in the financial year for which the intra-regional loss factors were pre-determined.*
- (iii) *The region boundaries should be located so that transfer limits between regions can be clearly defined, and transfer flows across regions easily measured, at the region boundary.*

- (iv) *The application of pre-determined static intra-regional loss factors within the proposed region and the application of a pre-determined inter-regional loss factor equation will not impact significantly on the central dispatch of generation and/or scheduled load that would result from a fully optimised dispatch process taking into account the effect of losses.*
- (v) *NEMMCO must aim to minimise the variation between the set of pre-determined loss factors and the resultant averaged intra-regional loss factors, and also any errors in the inter-regional loss factor equation across the trading intervals in the financial year for which the intra-regional loss factors were pre-determined.*
- (vi) *Where a connection point can be assigned to more than one region such that the criteria set out in clause 3.5.1(b)(2)(ii), (iii) and (iv) can each be met in either region, then the transmission network connection point will be assigned to the region such that the variation between the set of pre-determined intra-regional loss factors and the resultant averaged loss factors is minimised.*
- (vii) *Within the requirements of 3.5.1(b)(2)(i) to 3.5.1(b)(2)(v), the number of regions created should be minimised.*

Any change to regional boundaries requires that NEMMCO carry out a Code consultation with market participants beforehand and the change is approved by NECA. The implementation of any changes to regional boundaries can only take place, at a minimum, one year after approval by NECA (NEC Clause 3.5.3 (b)).

Historical data on intra-regional constraints between 1999 and 2002 reveals significant periods of intra-regional transmission constraint in all existing NEM regions.¹

In launching the review the SCO has noted that a moratorium on consideration of changes to region boundaries was instituted ahead of review of the arrangements and no boundary changes have occurred. This is despite one of the key criterion being met in a number of regions since start of market (i.e. intra-regional constraints binding for more than 50 hours — Clause 3.5.1(b)(2)(ii)).

¹ See Firecone 2003 "Regulatory and Institutional Framework for Transmission" Final Report, Firecone Ventures Pty Ltd, Sydney, November 2003, Annex 5.

3. PRIOR REVIEWS OF REGIONAL BOUNDARIES

As noted there have been a number of reviews of matters related to regional boundaries and the associated network constraints and risk management. This section provides a listing of the principal reviews conducted by relevant authorities by way of background for interested parties.

3.1. MAJOR REPORTS ON REGIONAL BOUNDARIES

Reviews related directly to the development of region boundaries include:

- NEMMCO review of regional boundaries, as required by the NEC (October 2000);
- NECA review of the criteria used to determine regional boundaries, as per Code Clause 3.5.1(e), which was part of the RIEMNS review;²
- NECA's REIMNS review and draft report in October 2000;
- COAG Energy Markets Review, (Chairman: Warwick Parer) December 2002; and
- Firecone 2003 "Regulatory and Institutional Framework for Transmission" Final Report, Firecone Ventures Pty Ltd, Sydney, November 2003.

3.2. REPORTS ON THE FORMULATION OF NETWORK CONSTRAINTS

In order to manage the power system and determine dispatch and pricing of scheduled generators and demand side blocks NEMMCO must utilise mathematical representations of network constraints. In the last three years there have been a number of reports on constraint formulation. These have been conducted by a number of the exiting market authorities which have been constrained to varying degrees to consider matters within their authority. The reviews include:

- NCRG (Network Constraints Reference Group) 2002, *Formulation of intra-regional constraints*, Issues and Options Paper, Final, NEMMCO, Sydney, January;

² NEMMCO 2000, *Review of Regional Boundaries in the NEM, Draft Report*, NEMMCO, Sydney, October 2000.

- CRA (Charles River Associates) 2003a, *Network Constraint Formulation: Impact on Market Efficiency*, report to NEMMCO, CRA, Wellington, 8 January 2003;
- CRA 2003b, *Dealing with NEM Interconnector Congestion: A Conceptual Framework*, report to NEMMCO, CRA, Melbourne, 24 March 2003;
- CRA 2003c, *Constraint Orientation: Principles and Pricing Implications*, report to NEMMCO, CRA, Melbourne 18 March 2003;
- IES 2003, *Optimising Combined Secure and Economic Dispatch*, Report to the Reliability Panel, IES, Sydney, 25 February 2003;
- NEMMCO 2001, *Market Report — Counter Price Flows on the NSW/Queensland Interconnector: 21 May 2001*, NEMMCO, Sydney, July; and
- NEMMCO 2003, *Final Report: Management of Network Limitations within the Snowy Region and Constraint Formulation in the NEM — interim actions*, NEMMCO, Melbourne, 3 July 2003.

The current state of play arising from these reviews is:

- Difficulties with network constraints on QNI and within the Snowy region resulting in negative settlement residues and reduced control of power system elements have led NEMMCO to seek a temporary Code Derogation which allows it to formulate inter-regional constraints in way that it claims best controls all generation and transmission affecting interconnector transfers (Option 4 in NEMMCO 2003, above). NEMMCO has also set out a policy for managing any negative intra-regional surpluses that arise under its preferred option. A significant part of the market objected to NEMMCO's choice of Option 4, claiming another option, Option 1, provided a better solution.
- After consultation NECA modified NEMMCO's Code Change proposal to allow Option 1 to be used because of the lack of consensus in the market place on the best option. NECA's proposal allows NEMMCO discretion to use either Option 1 or Option 4.
- The derogation sought by NECA lasts until 31 December 2004, allowing time for a more permanent solution to the problem to be formulated by the NEM Transmission Review.
- NECA's code change proposal was sent to the ACCC in December 2003 and is currently under consideration by the ACCC.

3.3. REPORTS ON SETTLEMENTS RESIDUES

Stage 1 of the RIEMNS review recommended changes to the Settlement Residue Auctions (SRAs) that are employed to facilitate the trading of electricity between different pricing regions, to improve their utility. These changes have been implemented. For example, linked bids for SRAs are now allowed and steps have been taken to improve the reporting of information on network capability.

A number of reports have looked at ways of “firming-up” existing SRA instruments, but some of these require changes to the way TNSPs operate and/or are regulated.

4. FURTHER CONSTRAINTS ON THE CURRENT REVIEW

A key output from the current review will be to propose (as appropriate) changes to clause 3.5 of the Code. This section briefly notes the constraints created by the Code and Market objectives. It also notes that related changes also may be required to other sections of the Code and also to other instruments, for example in relation to network investment. The scope to examine these related changes is seen as an important part of this review by the MCE.

Clause 3.5 of the Code is concerned with the framework, or principles, for establishing region boundaries – not boundaries per se. This is an important point as the current review will need to assess alternatives for the framework for future application. In undertaking that assessment it will be prudent to “road test” the proposed framework and develop an indicative set of region boundaries. This was also the path that NECA followed in its first draft of the RIEMNS review.

Options for change should also take into account:

- The Code objectives in clause 1.4;
- The Market objectives in clause 1.3 (b); and
- The market Design Principles in clause 3.1.4 (a).

Each of these is listed in Appendix A.

5. ALTERNATIVE PRICING AND DISPATCH ARRANGEMENTS TO MANAGE SECURITY AND MATCH SUPPLY AND DEMAND

Region boundaries are not fundamental elements of a competitive market. They are the result of design choices about how locational price differences will be represented in the spot market. However, where they are introduced they can have an important impact on dispatch, management of security, economic efficiency and market signals in relation to investment in both generation and networks.

Dispatch is the starting point for the prices that form the basis for each of these matters. The representation of the power system on which dispatch is determined therefore directly or indirectly affects these same matters. For example, dispatch has a very direct affect on the management of power system security, where dispatch is dependant on the choice of region boundaries, the boundaries affect management of security. Similarly, where dispatch, in conjunction with pricing algorithms are used to gauge the benefits that might be gained from investment in new network or production facilities then to the extent that region boundaries affect the outcomes the boundaries influence the efficiency of investment.

Although the key deliverable within this review is related to the principles that will drive future consideration of region boundaries it is constructive to consider possible outcomes for the core dispatch and pricing arrangement that will drive the underlying pricing arrangements. This section briefly explores the principal options for dispatch and pricing within the market.

Dispatch can be on a point by point, or nodal, basis or it can consider groupings of connection points or regions. However, it must deliver physically realisable outcomes. Pricing can cover a relatively wider range of options but in practice also must be at a nodal or regional basis. Alternative dispatch and pricing models encompass:

- Nodal dispatch
 - With nodal pricing, where each transmission busbar has a separate price used for settlements. Noting that “hubs” may be defined or evolve for trading purposes. In the NEM a fully “nodal” pricing model would involve over 300 busbars and prices;
 - Producing nodal prices which are aggregated to define regional prices used for settlements with some or all parties. For example, load prices could be constant across each jurisdictional region, while generator prices were nodal, or aggregated across smaller regions;
 - With regional prices, as above, but defined with respect to specified reference nodes, as in the current NEM;

- Regional dispatch/pricing models:
 - Such as the current NEM, with a small number of regions whose boundaries are defined by points of significant transmission constraints, and prices defined with respect to specified reference nodes;
 - With a larger number of regions than the current NEM;
 - With side payments for plant dispatched out-of-merit-order due to network and system security constraints;
- Regional dispatch models, as in the current NEM, with nodal prices being inferred from the constraint “shadow prices” implicit in the market-clearing solution; and
- Nodal pricing models, with or without price aggregation, in which side payments are also made with respect to constraints which can not be represented as link limits in the basic nodal model.

It is important to note that, in some cases, the implementation of a particular approach to pricing may only be optimal if it is implemented as part of a wider package. For example, some alternatives would only make sense if some expanded form of Financial Transmission Rights (FTRs) or SRAs were *also* introduced. The implementation of the entire package might require not only changes to the NEC, but also changes outside of the Code. Models have been developed where these instruments would be grandfathered to existing participants with a general view of leaving affected participants indifferent to the change.

Each model has potentially different implications for dispatch, regional pricing, participant connection point pricing and hedging. These implications affect judgements of the relative merits of each model and offer insights into what needs to be addressed in considering any changes to the NEM’s existing pricing model. On the other hand, some of these options can be configured so as to provide outcomes which are essentially equivalent to those from models of apparently quite different structures. Thus it will be critical to structure both assessment and consultation processes to ensure that attention is focussed on the real differences between options, and to distinguish carefully between differences with respect to outcomes, and differences with respect to the means by which those outcomes might be produced.

6. EVALUATION

This section summarises the preliminary evaluation topics that the team anticipates will be applied, including specific matters raised in discussions held with stakeholders who responded to an invitation issued on the MCE website. Further comment is invited. The issues will be assessed by the appropriate workstreams within the CRA team (technical, economic and commercial). The list here is not intended to be exhaustive or fully specified, rather it is presented to facilitate discussion, debate and input to the CRA team about matters of concern at this early stage of the review. The list, not in any priority order, is:

- Basis risk: Management of basis risk requires that participants can both analyse and have access to the means to manage risk. Where new instruments are proposed how well have these been proven/tested;
- Economic efficiency, this will be a key evaluation criteria but particular attention should be given to:
 - Are assumptions that link productive efficiency and dynamic efficiency valid under all circumstances;
 - What is the appropriate scope of costs and benefits to consider in undertaking analysis – for example in considering the impact of locational pricing on investment location how should the materiality of matters like land and fuel access be considered;
- Bridging the boundary between economic efficiency and basic commerciality concern has been expressed that counter-price flows – whilst possibly the analytically optimum outcome with certain region boundaries (including the current) is it commercially unacceptable and an indication that boundaries are in fact inappropriately placed;
- Market Power: Changes to boundaries, particularly changes that introduce smaller regions will be assessed;
- How will the dispatch process operate in relation to management of security – Is security dependant on direct physical monitoring or on predicted factors in constraint equations – as now;
- For outcomes that result in region boundaries that are only viable in conjunction with other instruments, eg Financial Transmission Rights (firm or non-firm) what level of assurance is there that the other instruments are practicable?;
- How well does the region boundary assessment process align with other network planning arrangements, in particular the regulatory test;

- For outcomes that call for allocated rights – for example grandfathered FTRs, how precisely are these to be allocated and settled;
- Is the advance notice period of a change to region boundaries adequate – what are the factors that influence this?;
- Are constraints to be developed and expressed consistently across the NEM?; and
- What is the impact of alternatives on demand side and embedded generation participation?

7. QUESTIONS

Contributors to the forum have been invited specifically to address the following questions:

1. The actual/perceived problems with the current arrangements;
2. The benefits and disadvantages that might exist with any of the possible solutions; and
3. Stakeholder objectives for a robust basis for evaluating alternative approaches to regionalisation issues in the future.

Attendees will also be invited to contribute additional thoughts on these questions for a limited time after the forum.

APPENDIX A: CODE AND MARKET OBJECTIVES

Market Objectives

The market objectives set out in Clause 1.3(b) of the Code are:

- (1) *the market should be competitive;*
- (2) *customers should be able to choose which supplier (including generators and retailers) they will trade with;*
- (3) *any person wishing to do so should be able to gain access to the interconnected transmission and distribution network;*
- (4) *a person wishing to enter the market should not be treated more favourably or less favourably than if that person were already participating in the market;*
- (5) *a particular energy source or technology should not be treated more favourably or less favourably than another energy source or technology; and*
- (6) *the provisions regulating trading of electricity in the market should not treat intrastate trading more favourably or less favourably than interstate trading of electricity.*

Code Objectives

The Code objectives in Clause 1.4 of the Code include:

- 1) *to provide a regime of “light-handed” regulation of the market to achieve the market objectives;*
- (2) *to provide for a set of market-oriented rules authorised by the ACCC governing market operations, power system security, network connection and access and network services pricing;*
- (5) *to provide efficient processes for changing the Code;*

Purpose of Market Rules

The purpose of the market rules is stated in Clause 3.1.2 of the Code:

The purpose of these market rules is to create a regulatory environment which promotes an efficient, competitive and reliable market for the wholesale sale and purchase of electricity.

Market Design Principles

The market design principles in Clause 3.1.4(a) state that:

These market rules are intended to give effect to the following market design principles:

- (1) minimisation of NEMMCO decision-making to allow Market Participants the greatest amount of commercial freedom to decide how they will operate in the market;*
- (2) maximum level of market transparency in the interests of achieving a very high degree of market efficiency;*
- (3) avoidance of any special treatment in respect of different technologies used by Market Participants;*
- (4) consistency between central dispatch and pricing;*
- (5) equal access to the market for existing and prospective Market Participants;*
- (6) ancillary services should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis. Where dynamic determination is not practicable, competitive commercial contracts between NEMMCO and service providers should be used in preference to bilaterally negotiated arrangements;*
- (7) the power of direction to provide ancillary services as a last resort to ensure system security should not be affected by the competitive market arrangements;*
- (8) where arrangements require participants to pay a proportion of NEMMCO costs for ancillary services, charges should where possible be allocated to provide incentives to lower overall costs of the national electricity market. Costs unable to be reasonably allocated this way should be apportioned as broadly as possible whilst minimising distortions to production, consumption and investment decisions; and*
- (9) where arrangements provide for NEMMCO to dispatch or procure an ancillary service, NEMMCO should be responsible for settlement of the service*