E Additional background information

E.1 Introduction

This appendix contains supplementary information on a variety of congestion-related topics including:

- E.2 – information on the types of constraints used in the NEM;
- E.3 – a review of CRA work on constraint management ;
- E.4 – the history of Network Support and Control Services; and
- E.5 – explanation of Positive Flow Clamping options.

E.2 Types of constraints

This section provides additional details on the three broad types of constraint used in the dispatch process to represent the underlying physical network. It explains the effects of each constraint type on regional reference prices. It also indicates the prevalence of each constraint type (based on an analysis of a single dispatch interval on a working day afternoon in July 2007, under "system normal" conditions).

The three broad types of constraint are:

1. *pure intra-regional constraints* (pure intra-regional limits);
2. *pure inter-regional constraints* (pure interconnector limits); and
3. *trans-regional constraints*, which may involve:
   (a) a single interconnector and local generation units (i.e. hybrid constraint);
   (b) multiple interconnectors and local generation units; or
   (c) interactions between two or more interconnectors, without any local generation involved.[350]

E.2.1 Pure intra-regional constraints

A pure intra-regional constraint restricts the flow of power through a constrained network element within a region, but is not affected by power flows from other regions; that is, the physical effects of the constraint are limited to a single region. If a binding pure intra-regional constraint affects power transfers to and from the RRN, then the RRP will reflect the impact of the constraint binding. If a binding pure intra-regional constraint does *not* affect power transfers to and from the RRN, then the RRP will *not* be affected in any way. These two cases are illustrated below. All examples assume that there are no network losses and that each generator offers all its capacity at the offer price indicated.

E.2.1.1 Case 1. A pure intra-regional constraint that affects the RRP

In this case, a pure intra-regional constraint binds in such a way that power flows to the RRN are affected. In order to balance supply with demand at the reference node, either additional energy is required or demand must be reduced. The incremental cost of procuring additional supplies of energy at the RRN as a direct result of the constraint binding is the congestion cost of the constraint. This congestion cost is reflected in the RRP.

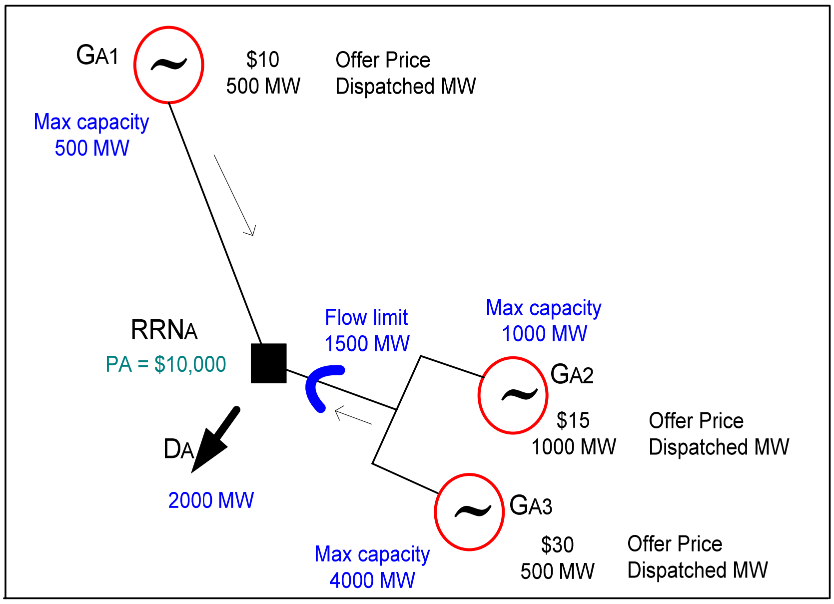
[350] For further discussion of trans-regional constraints and their pricing impacts, see the CRA report, *NEM Interconnector Congestion: Dealing with Interconnector Interactions*, Report to NEMMCO, Wellington, 2003. Available at http://www.mce.gov.au/assets/documents/mceinternet/InterconnectorInteractions20041123171938%2Epdf.

In the example in Figure E.1, there is no way of increasing generation to meet a 1 MW increase in load at the RRN because G_{A1} is at maximum output and the 1 500 MW transmission limit restricts additional output from G_{A3}. Therefore, in the absence of any demand-side bids, the marginal price at the RRN is set by VoLL, $10 000/MWh. It can be shown that the marginal economic cost of the congestion equals $9 970/MWh.

If this flow limit persisted over time, then the congestion costs implicit in the RRP could provide incentives for economically efficient investments to:

- upgrade the transmission line from G_{A3} and G_{A2} to the RRN;
- increase the amount of generation capacity located on the other side of the constraint, which has unrestricted access to the RRP; and
- reduce demand at the RRN through demand-side management.

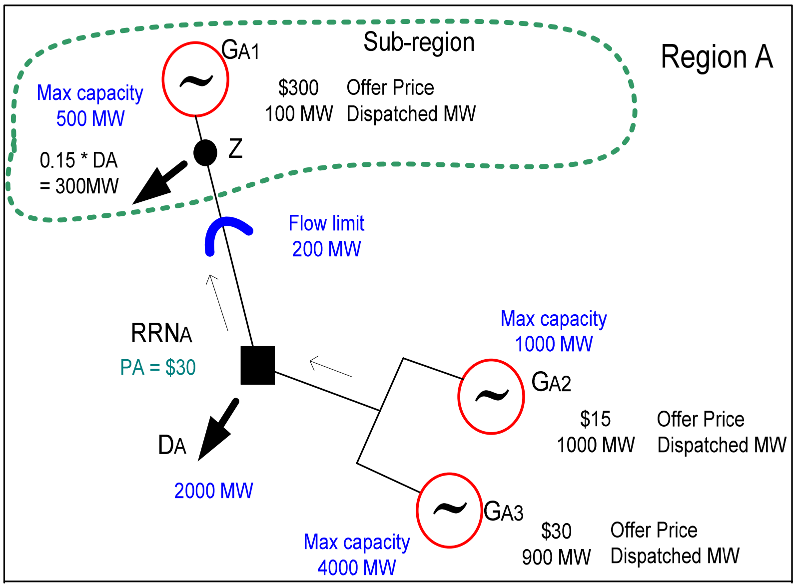
Figure E.1 Pure intra-regional constraint that affects the RRP



E.2.1.2 Case 2. A pure intra-regional constraint with no impact on RRP

In this case, a pure binding intra-regional constraint has no effect on the RRP. In the example in Figure E.2, total demand at the RRN is 2 000 MW, but 15% of this load (i.e. 300 MW) occurs physically in the sub-region containing node Z. Incremental demand at the RRN can be met by G_{A3}, at a price of $30, which sets the RRP. At that price, G_{A1} would not expect to be dispatched based on its offer price of $300. However, in order to meet the 300 MW demand at node Z, generator G_{A1} will have to be constrained-on to meet the 100 MW of the sub-regional load at Z that cannot be met because the 200 MW flow limit is binding.[351] Under the Rules, generator G_{A1} would be paid the $30/MWh reference price for all its output because it is constrained-on generation that has no effect on the ability to balance supply and demand at the RRN.

Figure E.2 Pure intra-regional constraint with no impact on RRP



The Rules also state that if a generator is initially unavailable but is directed by NEMMCO to start generating, it may apply for compensation payments when the RRP is below the price at which it is prepared to offer its capacity.

These pricing arrangements can provide incentives for:

- G_{A1} to declare itself unavailable, so that it can be compensated at a higher price than the reference price;[352] and
- the local TNSP and G_{A1} to enter into a NSA.

E.2.2 Pure inter-regional constraints

A pure inter-regional constraint is one in which the ability to transfer power between RRNs is affected not by power flows through a constrained element within a region

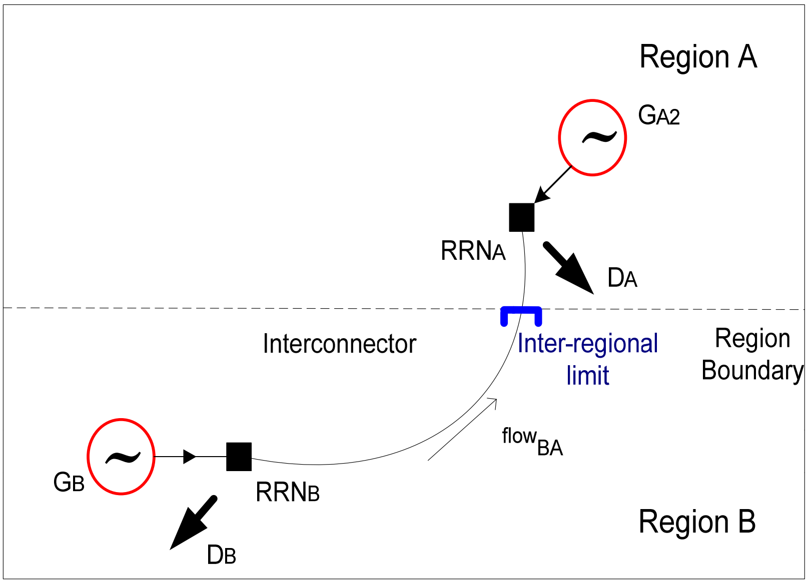
[351] Although all load is notionally treated as being at the RRN, in reality load occurs at different locations of the network. TNSPs and NEMMCO are both required to meet loads across the physical transmission network, not just at RRNs.

[352] This might occur if: a) G_{A1} has SRMC that are substantially above the prevailing spot price; b) G_{A1} is seeking to exercise its localised market power; or c) GA1 wishes to capture underlying economic rents that are not explicit because of the NEM's regional pricing structure.

but by the (security-constrained) physical capabilities of the interconnector itself (see Figure E.3 below).

Pure inter-regional constraints relate to pure interconnector limits (PILs). A PIL represents the sum of bounds on the actual physical lines joining adjacent regions, which may imply binding limits on the corresponding notional interconnector.

Figure E.3 Pure inter-regional constraint



Under the NEM's pricing rules, pure inter-regional constraints will be fully reflected in the price of energy at the boundary between two regions.

When there is a pure inter-regional constraint it is usually necessary for additional generation in the importing region to be dispatched to meet load in that region, even though it may have a higher offer price than that of generation located in the exporting region. Under these circumstances the price in the importing region will usually rise, with all customers in the importing region paying—and generators in the importing region receiving—the higher price, while customers and generators in the exporting region face a relatively lower price.

E.2.3 Trans-regional constraints

Trans-regional constraints involve both intra-regional generation and inter-regional flow terms. Trans-regional constraints are typically of non-radial form.

Most network limits, when expressed correctly in a fully-optimised formulation, produce "trans-regional" constraints.

There are three classes of trans-regional constraint, each of which has different characteristics and implications for pricing and the financial settlement positions of market participants:

1. a single interconnector and local generation units (i.e. hybrid constraint);

2. multiple interconnectors and local generation units; and

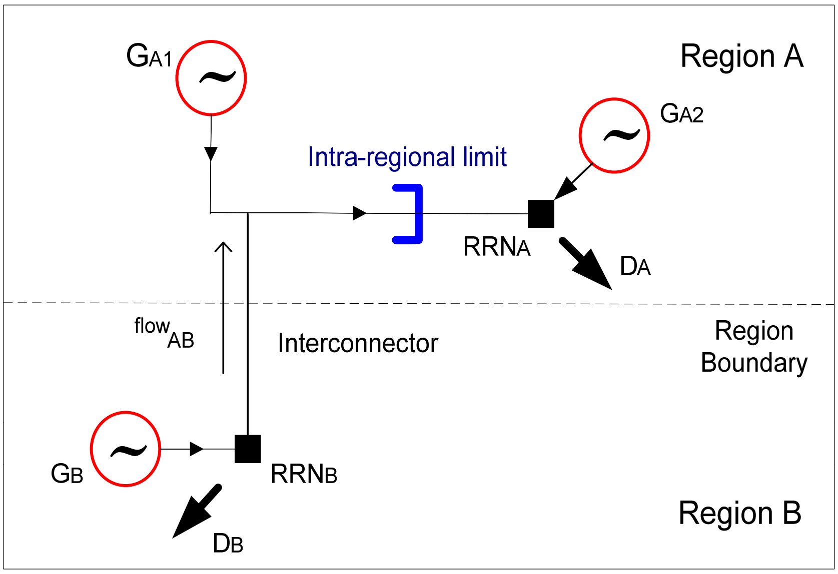
3. interactions between two or more interconnectors.

E.2.3.1 Single interconnector and local generation units (hybrid constraint)

We refer to a constraint involving a single interconnector and generation units within a region as a "hybrid" constraint.

In a hybrid constraint, power-flows through the constrained network element are affected by a combination of: flows along a single interconnector and flows through constrained network elements within a region. This is illustrated in Figure E.4, where there is a network limit between generator G_{A1} and the RRN in Region A (RRN_A). This limit affects the ability of both G_{A1} and the interconnector to supply power through the constrained element of the network. In this case, when the constraint binds, additional demand at RRN_A will be met by output from generator G_{A2}, whose ability to deliver power to the RRN is unaffected by the constraint. Given that G_{A2} will be the marginal supplier at the RRN, under the NEM Rules it will set the price at RRN_A. The price at the RRN in Region B (RRN_B) could also be affected by the constraint if flows on the interconnector change the marginal cost of balancing supply and demand at RRN_B.

Figure E.4 Hybrid constraint, involving a single interconnector and local generation units



The relative locations of the point of congestion, the RRN, generation, and the interconnector, all play a role in determining the extent to which the congestion affects the RRP in the region with the constraint and in the regions linked by the interconnector.

E.2.3.2 Multiple interconnectors and local generation units

In a trans-regional constraint involving multiple interconnectors and local generation units, power-flows through the constrained network element are affected by a combination of: flows along more than one interconnector and flows through constrained network elements within a region. These types of constraints typically involve either:

- a physical transmission loop wholly within one region, to which are connected local generators and interconnectors; or
- a physical transmission loop that spans two or more regions.[353]

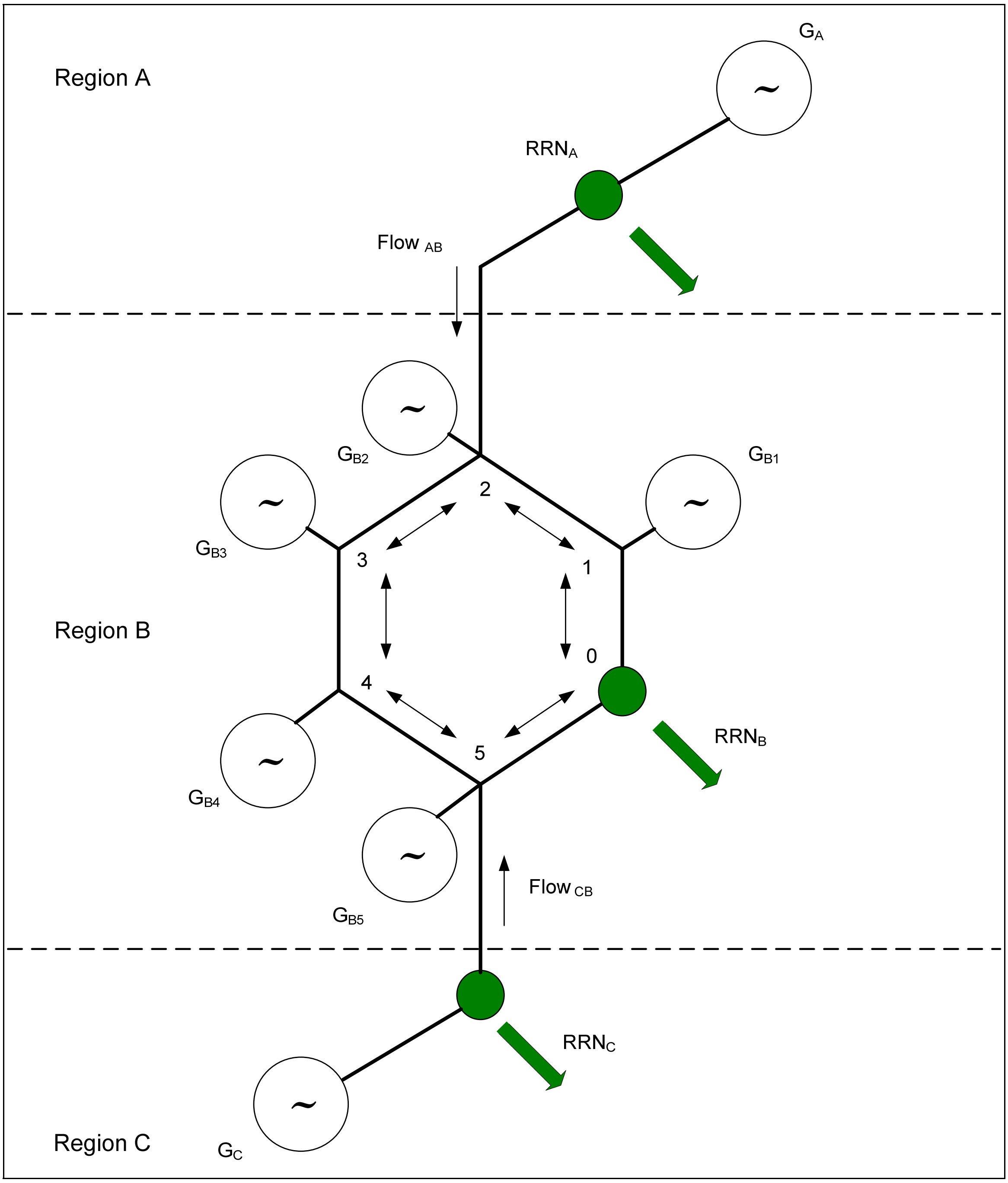
Figure E.5 provides an example of this type of constraint, where the loop is wholly within one region. In this example it is assumed that the network is unconstrained, that demand in Region B is high, and that the least-cost security-constrained dispatch results in:

[353] For example, the transmission loop spanning the Victoria, NSW and Snowy regions, prior to the abolition of the Snowy region. This Snowy loop and its pricing effects are discussed in Appendix A of AEMC 2006, *Management of negative settlement residues in the Snowy region*, Final Rule Determination, 14 September 2006, Sydney, pp. A2-A4.

- Region B importing power from Regions A and C; and
- the dispatch of generation in Region B to meet Region B demand.

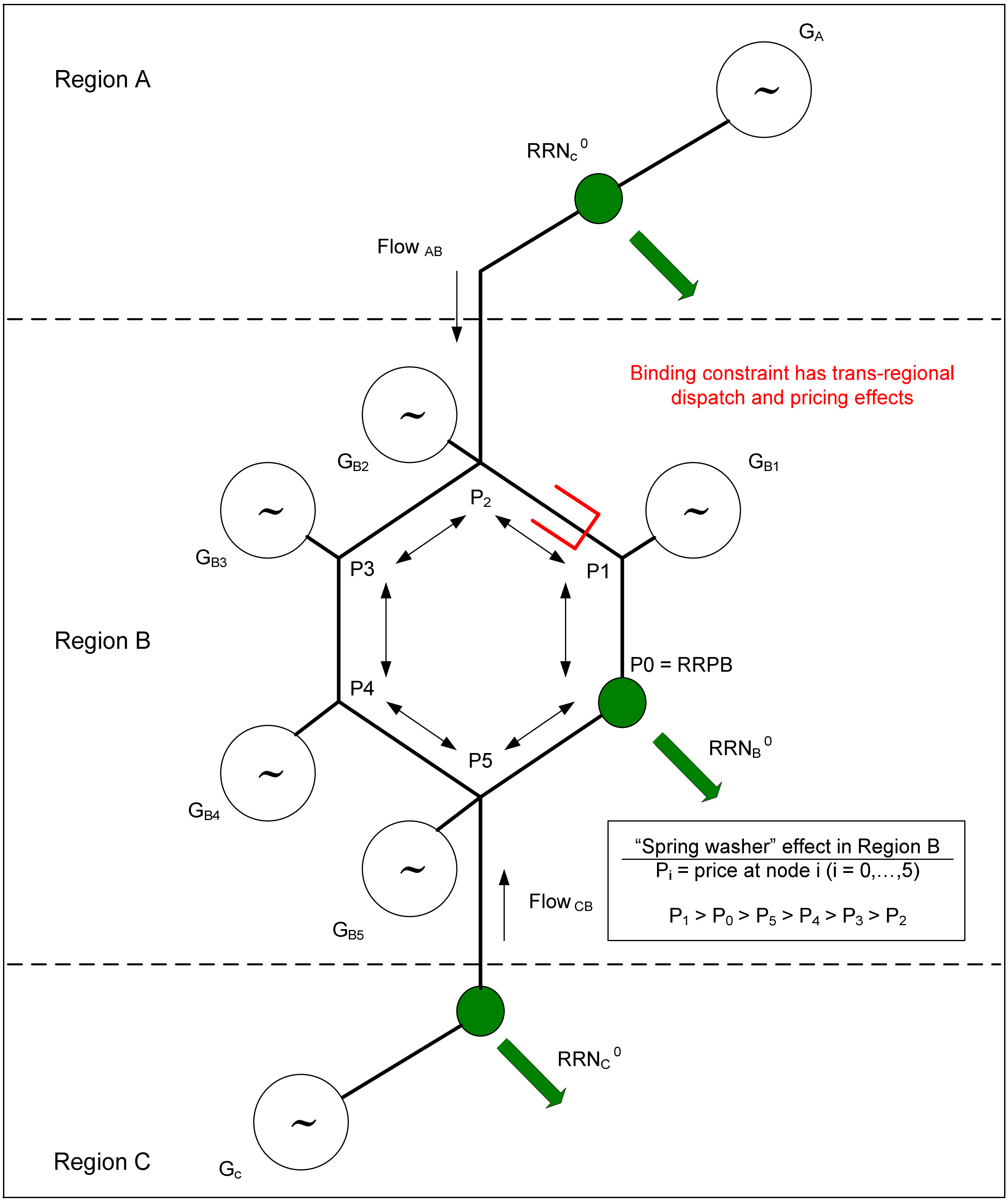
In this case, power flows around the loop within Region B towards the Region B RRN (RRN_B or node 0). The nature of the flow depends on the relative electrical impedance of the two alternate routes around the loop, measured at each of the five injection points 1 to 5, where generators (G_{B1} to G_{B5}) or interconnectors join the loop.

Figure E.5 Multiple interconnectors and local generation units, uncongested



Now assume that a constraint binds within Region B on the live connection G_{B2} to G_{B1} – i.e. nodes 2 and 1 (see Figure E.6). This binding constraint affects the ability to deliver power to RRN_B (node 0).

Figure E.6 Multiple interconnectors and local generation units, congested



The binding constraint in Region B between nodes 2 and 1 has the following effects:

1. A spring washer pricing effect arises within Region B, in which there is a pattern of nodal prices whereby the highest price occurs at the point where G_{B1} connects to the loop and the lowest price occurs where G_{B2} connects to the loop, with nodal prices falling in a clockwise manner. In this situation all the generators in Region B are constrained-on or -off relative to RRP_B, to some degree.

2. Generation and interconnector flow that most adds to congestion has to be backed off (i.e. G_{B2} and $flow_{AB}$).

3. Generation that most relieves the binding constraint has to be increased (i.e. G_{B1});

4. Generation and interconnector flow at all other points of the network will have to be adjusted so that the constraint is not violated (i.e. G_{B3}, G_{B4}, G_{B5}, $flow_{CB}$). The adjustments in the volume of power injections at these locations will be related to the marginal impact that the change has on power flowing through the constrained network element.

5. The mathematical coefficients representing the generator and interconnector flow variables are indicative of the impact that a marginal change in the value of the variable will have in relieving the binding constraint.

6. The value of changes in interconnector flows is captured in the NEM's pricing and settlement Rules, and accrues to the inter-regional settlement residue funds for $flow_{AB}$ and $flow_{CB}$.

7. The value of locationally adjusting generation within Region B to relieve the constraint (or not violate it) is not reflected in the settlement prices paid to generators within Region B. Instead, they are settled at RRP_B. However, the dispatched generation *volumes* of generators G_{B1} to G_{B5} do reflect the value that power injections at each location (based on offers) have in relieving the constraint. This can result in generators being constrained-on or constrained-off, relative to the settlement price, RRP_B. When generators are constrained-on or -off in Region B, they face dispatch risk and have incentives to alter their offers to mitigate that dispatch risk by aligning their dispatch volumes with the volumes they are willing to supply at RRP_B. This can result in "dis-orderly bidding", which can potentially have a negative impact on the economic efficiency of dispatch, and increase uncertainty about the level of interconnector flows and inter-regional price differences. That is, "dis-orderly bidding" can reduce the firmness of the inter-regional settlement residues (IRSRs), thereby diminishing the usefulness of IRSR units as a means of managing inter-regional trading risks.

8. Note that this single binding constraint within Region B affects dispatch, pricing and settlements across the entire market, as follows:

   (a) With local demand unchanged in Region A, and generator offers unchanged, the price in Region A will fall—both relative to RRP_B and in absolute terms—because the effective demand in Region A (i.e. load in Region A plus net exports) has fallen relative to the supply curve in Region A.

   (b) Similarly, with local demand in Region C unchanged, the price in Region C will rise towards that in Region B, as more costly generation in Region C is dispatched to meet the higher level of net exports from C to B.

As before, the relative locations of the point of congestion, the RRN, generation, and the interconnectors, all play a role in determining the extent to which the congestion affects the RRP in the region with the constraint and in the regions linked by the interconnectors.

For further discussion of trans-regional constraints and their pricing impacts, see the CRA report, *NEM Interconnector Congestion: Dealing with Interconnector Interactions.*[354]

E.2.3.3 Interactions between two or more interconnectors, and that do not involve generation

Interactions between two or more interconnectors, that do not involve generation, are very rare (see section E.2.4 below). However, there are a few examples that occur in the NEM, which primarily relate to stability constraints.

In these cases where there is no generation directly represented in the constraint, flows on one interconnector are affected by flows on at least one other interconnector—i.e. there is interconnector interaction. These pure interconnector interactions can take several forms:

- requiring greater flow on one interconnector in order for flow on the other to increase;
- requiring counter-price flow on one interconnector to support flows on other interconnectors in order to minimise the total costs of dispatch; and
- requiring stability constraints designed to keep the six regions of the NEM electrically intact in the event of a contingency that creates a transient stability or voltage stability issue.

The most common type of interacting interconnector constraints also involve generation (see section E.2.4 below). These are discussed in section E.2.3.2.

E.2.4 Incidence of constraint types

The incidence of the three broad types of constraint provides an indication of how likely they are to affect the setting of RRPs in any dispatch interval. A snapshot view of the incidence of constraint types can be gauged by examining the constraints that were invoked during a particular dispatch interval.

NEMMCO randomly sampled a dispatch interval in the mid to late afternoon of 17 July 2007, and classified the constraints that were invoked. There were only a few prior outages of transmission plant on that day, so the dispatch interval seems to be representative of system normal conditions.

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354 CRA(2003b) *Dealing with NEM Interconnector Congestion: A Conceptual Framework*. Released by the National Electricity Market Management Company of Australia, March 2003.
CRA(2004c) *NEM Interconnector Congestion: Dealing with Interconnector Interactions*. Released by the National Electricity Market Management Company of Australia, October 2004
http://www.mce.gov.au/assets/documents/mceinternet/InterconnectorInteractions20041123171938%2Epdf

Here are the findings based on an analysis of that single dispatch interval:

1. At any point in time under system normal conditions, it can be expected that up to about 400 constraints will be invoked and active in the dispatch process.

2. Of these 400, around 20% (i.e. 80) are associated with FCAS requirements, and half of these FCAS constraints are for Tasmania.

3. Around 75% (i.e. 300) of the total constraints are trans-regional constraints that involve at least one interconnector.

4. Of the 300 non-FCAS constraints that involve interconnectors, about 230 of these also involve generating units. That is, around 77% of the non-FCAS constraints are trans-regional constraints that involve either:

   (a) a single interconnector and local generation units (i.e. hybrid constraint); or

   (b) multiple interconnectors and local generation units.

5. To put it another way, around 58% of the total of 400 constraints (i.e. 230/400) invoked in the dispatch interval, are trans-regional constraints involving generation interacting with one or more interconnectors.

6. Around 31% (i.e. 120) of all constraints are trans-regional constraints involving more than one interconnector.

7. Of the 120 trans-regional constraints involving multiple interconnectors, about half have two interconnector terms. However, there are six trans-regional constraint equations that include all five interconnectors (including Basslink) in them. These six constraints most likely relate to stability constraints.

8. Of these 120 constraints, about 55% have different signs on the interconnectors and 45% have the same sign. This indicates an interaction between the interconnectors, which could include:

   (a) one interconnector supporting flows one or more other interconnectors;

   (b) one interconnector blocking flows one or more other interconnectors;

   (c) the minimisation of electrical losses on flows across two or more interconnectors; and

   (d) stability constraints designed to keep the NEM electrically intact in the event of a disturbance.

9. Only around 20 constraints (i.e. 5% of the 400 total, and 6.25% of the 320 non-FCAS constraints) were either:

(a) outage related;[355]

(b) pure intra-regional; or

(c) pure inter-regional.

The conclusion of this analysis is that, under system normal conditions, the majority of active transmission constraints in the NEM are trans-regional constraints, and that the bulk of these trans-regional constraints involve one or more interconnectors interacting with generation in a region.

[355] There were around 12 network outages and restrictions that day, comprising: a) 1 constraint arising from one of the three Directlink cables being out of service; b) about 6 constraints to manage an outage on the Ballarat to Kerang 220 kV circuit; c) several constraints relating to the Armidale transformer, which restricted flows into the 132 kV system that parallels QNI; and d) a limit on power flows between Central Queensland and Southern Queensland.

E.3 Review of CRA work on constraint management

E.3.1 Introduction

This section reviews recommendations on constraint formulation and pricing made to the MCE by Charles River Associates (CRA) in 2004.[356] It also reviews the submissions made to the associated consultation, and CRA's responses to those submissions.

The AEMC is required, under clause 3.3 of the Congestion Management Review's Terms of Reference, to have regard to CRA's work on constraint management and to use the submissions to the associated consultation as the basis of our own review of constraint management.[357]

CRA presented its Consultation Report, containing draft recommendations on constraint management, to the MCE in September 2004. In response to this report, the MCE received a total of 24 submissions.[358] CRA then completed a Final Report for the MCE in April 2005, which the MCE published in 2007.[359] In the Final Report, CRA made the same recommendations as in the Consultation Report but clarified a number of matters in light of the submissions.

CRA's Consultation Report addressed the criteria for setting future boundaries for price regions, and advocated a staged approach to congestion management. It also looked at how the technical characteristics of the transmission network are represented in the constraint formulation process by NEMMCO. The key recommendations were as follows:

- Implicitly absorb within the energy market the costs of minor levels of congestion.
- Regularly publish information on existing and emerging congestion in the NEM.
- Introduce consistent constraint formulation throughout the NEM, as well as a practical measure to limit the scope for counter price flows between regions.
- Introduce an economic test in the criteria for assessing proposed changes to the regional structure.
- Establish a timeframe for conducting regional boundary reviews, announcing boundary changes and maintaining any new regional structure.

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356 Charles River Associates, Consultation Draft, *NEM – Transmission Region Boundary Structure*, September 2004.

357 Ministerial Council on Energy, Congestion Management Review Terms of Reference, 5 October 2005, p.4.

358 Organisations which made submissions are listed in F3.5. The submissions themselves are available from the MCE website: www.mce.gov.au

359 Charles River Associates, Final Report, NEM - Transmission Region Boundary Structure, April 2005.

- Ensure consistency between the application of the Regulatory Test and region boundary reviews.

- Develop a contracting/pricing mechanism to deal with material congestion until the problem is addressed by investment or regional boundary change.

- Request market authorities to develop a program to implement a congestion management contracting and pricing regime, using the proposal for Constraint Support Pricing and Contracting as a starting point.

CRA's recommendations were based upon the view that transmission constraints, at least within regions, will not be prolific because transmission investment will occur in a timely manner, and that stability in the market environment promotes the certainty and predictability required to encourage suitably located generation investment. CRA concluded that full nodal pricing (and settlement) of both generation and load is not required. However, CRA did recommend that, given the regulatory framework for network investment, it would be beneficial to implement a form of targeted generator nodal pricing and settlements, which would be utilised to manage material congestion. Under this approach, according to CRA, pricing and settlement for loads would continue to be regional.

CRA's views and recommendations on constraint management and pricing fall into four topics:

- constraint formulation;

- responding to strategic bidding behaviour by generators;

- managing counter-price flows; and

- constraint contract and pricing mechanism.

By topic, this section reviews CRA's draft findings and recommendations, the responses from submissions, and CRA's rejoinders from its Final Report.

E.3.2 Constraint formulation

E.3.2.1 CRA draft report recommendations

CRA made the following recommendations as to how constraints should be formulated in the NEM for optimal dispatch:

- No change should be made to the existing dispatch objective, which is to optimise each dispatch run on the basis of the prices presented at the time.

- NEMMCO should adopt a consistent approach to constraint formulation and use a direct physical representation (either Option 4 or Option 5). CRA noted this is consistent with the market design principles in the Code that call for NEMMCO decision-making to be minimised.

- Options 4 and 5 each allow for variables to be fully optimised by the dispatch engine and will produce physically equivalent outcomes assuming the same physical network representation. Option 4 should be used if dispatch uses a regional model, and has varying constraints' orientations yielding prices corresponding to different regional RRNs. Option 5 should be used if dispatch uses a full network model[360].

- The issue of whether or not to apply Option 5 is not dependent upon the implementation of nodal pricing because dispatch and pricing arrangements can be decoupled. The choice between Option 4 and Option 5 should be based upon system security. NEMMCO should conduct a review if it believes a full network model (Option 5) is necessary in order to meet its obligations for system security.

- Constraint equations should be reviewed and updated on a regular basis.

- The shadow prices behind intra-regional constraints should be published.

E.3.2.2 Summary of submissions

There was overwhelming support for CRA's recommendation that NEMMCO adopt a consistent approach to constraint formulation using direct physical representation of the network.

Snowy Hydro agreed that dispatch and pricing can be decoupled, and commented that the dispatch model must represent the underlying electrical network in order to correctly manage loading.

Most of the submissions supported the publication of shadow nodal prices. Only the Queensland Generators[361] argued against it, commenting that the information would not mean much because of the bidding wars between generators and because bidding is driven by dispatch rather than revenue.

Option 4 versus Option 5

Regarding the choice between Option 4 and Option 5, most submissions were fairly neutral, while some argued in favour of Option 4.

The Queensland Generators group considered Option 4 best because it provides optimal dispatch of plant and secure utilisation of the full transmission capacity. It thought CRA overstated the possible benefits for system security from applying Option 5 (full network model), and argued that the approximation of fixed loss factors under Option 4 is not a problem when many constraints use actual measured flows in feedback-type constraints. It also argued against other options raised

[360] A full network model directly represents the electrical characteristics of each and every physical transmission element, the limits applying to that element, as well as system security constraints that apply to more than one element.

[361] The joint submission from the "Queensland Generators" included CS Energy, Enertrade, InterGen, Stanwell and Tarong Energy.

previously, because such options give a particular category of generators priority over others by removing them from the left-hand side of the constraint and because this allocation of priority can be arbitrary.

Delta Electricity supported the adoption of Option 4 constraint formulation but added that it can be enhanced through the equalisation of constraint equation coefficients. It recommended that near-identical constraint equations be equalised in order to prevent inappropriate and perverse constraints.

"The Group"[362] thought a full network model would not be required if Option 4 were supported by an appropriate counter-flow management regime. It also supported Delta's equalisation proposal.

Energy Retailers Association of Australia (ERAA) said it would support the implementation of the full network model if NEMMCO could demonstrate that the cost of implementation would be outweighed by the benefits.

Many submissions supported the recommendation for NEMMCO to consult on whether Option 5 is required for system security. Both the National Generators Forum (NGF) and Southern Hydro thought the consultation should evaluate other costs and benefits besides system security. The Group argued against the consultation, noting that Option 4 was in part proposed by NEMMCO for system security reasons.

E.3.2.3 CRA Final Report: further comments

CRA maintained its position that a consistent and direct physical representation of the network (either Option 4 or 5) would be best because it would allow decisions on physical representation to be decoupled from the design of the pricing regime.

E.3.3 Responding to strategic bidding behaviour by generators

E.3.3.1 CRA draft report recommendations

Having noted that addressing adverse bidding behaviour is required for congestion management and that, whether Option 4 or 5 constraint formulations are used, some generators may have incentives to bid below their short-run marginal cost of production (SRMC) where intra-regional constraints bind, CRA made the following recommendations:

- The form of the general constraint equation should not be modified to prevent or deter distorted bidding. Rather, such behaviour should be referred to and dealt with by the relevant (competition) authorities.

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[362] "The Group" consists of AGL, Delta Electricity, Loy Yang Marketing Management Company, Macquarie Generation, Stanwell Corporation, Yallourn Energy, Powerlink and Transgrid. Their submission was prepared by Frontier Economics.

- Changes to constraint formulation or to region boundary structure may only solve some bidding behaviour but could create new adverse bidding. This is because network congestion will always create pockets of localised market power.

E.3.3.2 Summary of submissions

Some of the submissions questioned CRA's view that strategic bidding behaviour is anti-competitive. Enertrade considered it grossly inaccurate to characterise as inappropriate those bidding practices which respond to the current rules, and said there is no evidence to support CRA's view that such behaviour is an abuse of market power. TXU Energy thought the additional cost of the increased risk burden caused by uncertainty of dispatch needs also to be modelled to understand the current dispatch inefficiency, and noted that NEMMCO's constraint equations are not designed to deal with the allocation of transmission capacity. The increased risk burden, in turn, would lead to strategic behaviour which would result in the withdrawing of capacity from the contract market.

Other submissions questioned the value of referring these matters to competition authorities. The Group considered that referring market power issues to the ACCC would be ineffective. It noted that the ACCC's approval of the National Electricity Code Administrator's (NECA) rebidding Code changes did not follow directly from its enforcement of the part IV competition provisions of the Trade Practices Act, but rather from the Code requirement that virtually all Code changes are to be authorised by the ACCC. Therefore, simply 'referring dis-orderly bidding' to the ACCC would be unlikely to result in any control over this behaviour unless accompanied by a relevant Code change proposal. The Group argued that even in these circumstances, as with the rebidding Code changes, the ACCC would probably be reluctant to intervene in participant bidding behaviour that did not involve an exercise of market power for a proscribed purpose or anti-competitive agreements. It added that if the good faith bidding provisions in clause 3.8.22A were applied in a way that seeks to prevent dis-orderly bidding—by, for example, proscribing certain negative bids—this would represent a major behavioural intervention in the market and could create a great deal of uncertainty and dispatch inefficiency.

E.3.3.3 CRA Final Report: further comments

CRA stood by its recommendation to refer concerns about inappropriate bidding behaviour to the relevant authorities, claiming that it is important to have a clear separation between market operations and responsibility for enforcing trade practice provisions. It noted that this sort of policy response is not new to the NEM, because the ACCC has in the past imposed conditions on specific parties' participation in the SRA contracting process (e.g. capping the number of IRSR units Snowy Hydro can bid for).

E.3.4 Managing counter-price flows

E.3.4.1 CRA draft report recommendations

Under the current Chapter 8A, Part 8 Network Constraint Formulation derogation of the Rules, in instances where NEMMCO considers that counter-price flows will lead to the accumulation of negative settlement residues, it can use a discretionary constraint formulation to stop this accumulation. CRA noted that this derogation means adverse bidding behaviour is being addressed through constraint formulation and that this will reduce short-term bidding behaviour when adverse bidding behaviour is not presented and will complicate the dispatch process. It added that negative residues can occur as part of the economically optimal solutions to dispatch around a network loop, and therefore using constraint formulation to address this is inefficient.

CRA's view was that this approach is appropriate in the short-term but that in the long-term such a derogation would decrease efficiency as more and larger loops are created in the network. It recommended that the derogation be allowed to continue and that the use of a simple constraint on network transfers to minimise negative settlement residues by NEMMCO should also be allowed. CRA's preference was to use clamping of the interconnector instead of an Option 1 formulation to address negative residues.

However, CRA advised that another mechanism which is external to the dispatch process should be implemented to address inefficient bidding behaviour. It suggested that a contracting mechanism (i.e. CSP/CSC) be assessed as a longer term and more general instrument to influence bidding and deal with negative IRSRs.

E.3.4.2 Submissions summary

There was a mixed response to CRA's recommendation to continue the derogation that enables NEMMCO to intervene to manage counter-price flows.

ERAA, NGF, Southern Hydro, Ergon Energy and Powerlink supported NEMMCO intervention to manage counter-price flows to restrict negative residues forming. Most of these submissions agreed with CRA that this is a temporary measure and that the intervention will face problems if increased loop flows appear between pricing regions.[363]

Origin Energy argued against the current intervention to manage counter-price flows, claiming that it did not impart effective discipline on participants nor did it lead to a satisfactory allocation of access to market when constraints bind. Hydro Tasmania stated that the proposals do not adequately address the issue of negative settlement residues and that the different treatment of local generation to

[363] Southern Hydro stated that the CSP/CSC mechanism should be developed for more persistent constraints or where loop flows make the current regime unworkable. Ergon Energy stated that continued intervention to limit negative residues was supported but should be reviewed once major AC transmission loops appear between pricing regions.

interconnector flows allowed under the derogation is not consistent with a national market.

The Queensland Generators, on the other hand, thought that negative residues should be funded out of auction proceeds. AGL disagreed with CRA's recommendation. Because negative residues may arise from economic dispatch, it supported a better funding mechanism for negative residue rather than intervention by NEMMCO and the artificial reduction of interconnector capacity.

The Group suggested that instead of the current intervention to minimise negative settlement residues, a more robust and transparent approach to reducing the occasional counter-price flow outcomes of Option 4 could be achieved by implementing a NEMDE forward-looking run. In effect, this would involve a double run of the NEMDE after ramping back inter-connector flow if the first run of the NEMDE showed that counter-price flows would occur. The Group considered the operating speed of the NEMDE sufficient for this approach to be feasible.

E.3.4.3 CRA Final Report: further comments

CRA reaffirmed the recommendations from its Consultation Report. It added that negative residues could be controlled by limiting flow on interconnectors even though this may also curtail efficient dispatch. It also noted that future development of the network is likely to lead to more occasions when anything but a direct physical representation will reduce efficiency of dispatch, especially as more and larger loops are created in the network due to normal expansion. Therefore CRA's preference is for a constraint contract and pricing mechanism, as it offers the opportunity for contracts to be employed to alter the incentives on market participants to encourage bidding in a manner that also limits flow on an interconnector without the need to resort to flow limits.

E.3.5 Constraint contract and pricing mechanism

E.3.5.1 CRA draft report recommendations

CRA made the following recommendations and observations:

- There should be a selective introduction of contracting and pricing of network congestion within and between regions where there are economic benefits that would otherwise be lost. This would create incentives for more efficient responses to congestion.

- Selective implementation of a contracting and pricing mechanism should be triggered when congestion passes an impact threshold. However, region boundary change should be used for significant and persistent constraints.

- The defining characteristic of this mechanism should be to create incentives for responses to manage particular constraint situations rather than to hedge against price differences.

- Voltage control and network support agreements are forms of a contracting and pricing mechanism which currently operate in the NEM.

- CRA developed the Constraint Support Pricing (CSP)/Constraint Support Contracts (CSC) mechanism. The CSP component would provide pricing incentives to respond to congestion (CSP) while the CSC component would provide price insurance.

- Due to the sensitive commercial impact of introducing such a regime, an operational investigation with considerable involvement from market participants should be instituted to assess implementation.

- Criteria should allow for the introduction of specific contracting and pricing for a constraint on a case by case basis.

E.3.5.2 Summary of submissions

Views were divided as to whether a contract and pricing mechanism would be required. Furthermore, most submissions found that the CRA report did not provide sufficient detail on how such a regime would be implemented. Many commented that the key issues of any mechanism would be how to allocate contracts and how to manage generators exposed to negatively priced contracts. The other difficulty raised in regard to contracts was how to define the expected efficient output of each generator. Some submissions recognised that there will never be agreement from market participants on the allocation methodology and that the decision will involve winners and losers.

The Queensland Generators stated that a mechanism external to the dispatch process is preferable to addressing inefficient behaviour, and accepted CRA's CSP/CSC mechanism in principle, subject to further assessment, especially in the areas of allocation and governance.

Enertrade thought the current arrangements for addressing intra-regional constraints—namely NSAs and constrained-on compensation payments—do not do enough, but it wanted to see more detail on the CSP/CSC scheme before endorsing it. Its initial view was that CSP/CSC arrangements would not be effective in managing intra-regional constraints that do not have a direct or indirect inter-regional impact because they would not generate net income for generators who relieved the constraint. Enertrade also considered it important to examine all options, including possible improvements to the existing NSA and constraints on direction arrangements. It also stated that in relation to the CSP/CSC regime, dynamic changes in the right-hand side of constraint equations would make it difficult for generators to predict and dispatch to their relative allocations under CSCs.

Snowy Hydro strongly supported the proposed CSP/CSC regime. It thought such a regime would eliminate the current perverse bidding incentives and would remove the requirement for intervention actions by NEMMCO (either to maintain system security or to minimise negative residues) and hence would firm up IRSRs.

Origin Energy supported the implementation of a CSP/CSC regime to address significant congestion in-between boundary reviews, but only to the extent that an acceptable allocation methodology could be developed for CSCs.

Ergon Energy disagreed with the use of CSP/CSC as an effective congestion management mechanism on the grounds that it depends on some deemed average impact that the generator has on a constraint. It noted that the real-time impact would not be constant. The deemed generator's parameters would need to be updated regularly to maintain some degree of consistency with physical power-flow behaviour. Ergon also considered that the CSC would be a non-firm hedging instrument. Overall, it thought CRA's proposed CSP/CSC arrangements would lead to nodal pricing; and in its submission Ergon provided an analysis of Queensland and suggested that locational energy prices would not significantly affect generator investment for at least the next decade. Its view was that CRA had underestimated the amount of central control and regulatory intervention required to implement the proposed regime.

The Group did not support the CSP/CSC proposal because it thought the primary mechanism for managing significant network congestion should be the regional boundary criteria.

InterGen said the allocation of CSCs should ensure that incumbents' generators were not disadvantaged. It considered it essential that contracts be allocated to existing generators free of charge so that they did not suffer significant revenue or value changes within a region review period. Failure to allocate to existing generators would create a major flaw in the logic for the proposed regime and would fail to achieve the desired outcomes.

Macquarie Generation thought a CSP/CSC regime unnecessary because there are only a few instances of intra-regional congestion in the NEM. It argued that the proposal for periodic assessment of region boundaries combined with the transmission augmentation framework should be sufficient.

Powerlink considered current intervention under the derogation to be a better measure than the proposed CSP/CSC mechanism. It thought the CSP/CSC regime proposed by CRA would not provide the right investment signals to TNSPs to alleviate the congestion.

The ACCC commented that more work is required on the full nodal pricing solution, especially on the implementation costs/issues, and attached a report from IES showing that the potential benefits from nodal pricing are significant.

The ACCC also said that further work is needed on CSP/CSCs, especially on the issue of allocation. Its submission contained a paper on CSP/CSCs by Dr Biggar, which noted that the CSP part of CRA's proposal provided the correct pricing signals to generators in the event of an intra-regional constraint. However, Dr Biggar raised a number of concerns with respect to CSCs, in particular that it is not clear how these grandfathered rights would be determined. He demonstrated that if the grandfathered rights were set in a particular way—specifically, equal to the dispatch of the generator under the existing arrangements—then no generator nor the system operator was left worse off as a result. However, he thought that any attempt to define a set of grandfathered rights would be difficult and contentious. In addition to the issue of how to allocate these rights, it was also not clear for what period of time these rights would be set and how rights would be reallocated in the event that new generation comes on line in an area where an intra-regional constraint occurs. Further, the party responsible for the determination and allocation of these rights must be established. The ACCC also noted that CSPs would provide the correct pricing signals to generators but not to load.

Taken together, the submissions indicated that more work and detail are required on the following:

- allocation of CSCs;
- management of potential "property rights" issues;
- governance frameworks that are likely to be implemented;
- potential arrangements for liability and accountability;
- commercial risk management issues;
- who would identify the need for CSP/CSC and what criteria or threshold would apply in implementing this regime?
- how would NEMMCO use the surplus revenues from this regime? —would they be auctioned or allocated? who would they go to? on what basis would this be determined?
- who would be the winners and losers out of this process?
- would retailers be allowed to hold CSC?

Some of the submissions commented on the possible triggers for a CSP/CSC implementation. The Group considered that the trigger threshold for any CSP/CSC implementation should be based upon the same methodology as region boundary assessments, noting that the trigger thresholds set for the regional boundaries would determine the thresholds for any CSP/CSC implementation. As CRA said, given that the CSP/CSC would be a temporary substitute for any regional boundary, the implementation triggers would be lower than those for regional boundaries. AGL was concerned that temporary measures like CSP/CSC would become entrenched and it therefore proposed that any application of these mechanisms be strictly time-limited.

Snowy Hydro recommended the CSP/CSC implementation process be triggered by NEMMCO whenever constraint costs exceeded $10 000. It argued that the total transaction and implementation cost for a specific CSP/CSC location would be extremely low.

InterGen stated that the criteria for selecting locations for CSP/CSCs needed to be very tight and that alternatives such as NSA would be equally effective. It added that CSP/CSC criteria should be a net benefit test and that participants' transactions costs should be included in that assessment.

E.3.5.3 CRA Final Report: further comments

CRA maintained its position that a flexible localised arrangement to create incentives to manage the effects of congestion should be developed to complement the proposed region boundary review process. It recommended that market authorities develop proposals for an intra-regional contracting/pricing mechanism based upon the broad design of its proposed CSP/CSC mechanism. It considered that the contracts should be crafted to suit characteristics and objectives of each application that are most important.

Although CRA acknowledged that the number and scope of such localised mechanisms could be set by policy requirements, it thought that the regime would be best suited to managing a small number of local conditions under the broader regulatory framework because it would become overly complicated if used universally across the NEM. CRA's expectation, based on the history of the NEM and analysis of the potential level of congestion under the investment framework, was 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.

CRA also recognised that the proposal could be applied to manage the potential misuse of localised market power that occurs with congestion. It noted that this sort of policy response is not new to the NEM: the ACCC has, in the past, imposed conditions on specific parties' participation in the SRA contracting process.

E.3.6 List of submissions to CRA draft report

All of the following made Regional Structure Review Submissions:

- Queensland Generators—comprises CS Energy, Enertrade, InterGen, Stanwell and Tarong Energy
- Australian Competition and Consumer Commission (ACCC)
- Australian Gas Light Company (AGL)
- Energy Networks Association (ENA)
- Southern Hydro
- Origin Energy
- TXU
- Creative Energy Consulting
- CS Energy
- Delta Electricity
- Energy Retailers Association of Australia (ERAA)

- Enertrade
- Ergon Energy
- Hydro Tasmania
- InterGen (Australia) Pty Ltd
- Macquarie Generation
- National Generators Forum (NGF)
- Powerlink
- Snowy Hydro
- Stanwell
- Tarong Energy
- The Group—comprises AGL, Delta, Loy Yang Marketing Management, Macquarie Generation, Stanwell, Yallourn, Powerlink and TransGrid
- TransGrid
- Gallaugher and Associates of Australia

E.4 Network Support and Control Services

Network Support and Control Services (NSCS) are those services procured and delivered by either Transmission Network Service Providers (TNSPs) or NEMMCO for the purpose of managing network flows to ensure that the power system is operating securely and reliably. The framework for NSCS procurement and delivery have been subject to repeated reviews since 1997. This section describes the historical development of the arrangements and provides a comprehensive definition of existing NSCS and the current rationale for the various forms of service provision.

E.4.1 History of Network Support & Control Services

This account of the development of NSCS provides a context for understanding how the definition of key services has evolved and how various reviews throughout the history of the NEM have impacted on responsibilities for the procurement and delivery of NSCS.

E.4.1.1 Ancillary services pre market start

The National Grid Management Council

In the early history of the NEM's development, when the National Grid Management Council (NGMC) was the driving force, service categories were not clearly or consistently defined among the vertically integrated (State-owned) electricity entities. Consequently, approaches and definitions adopted by the NGMC were the first attempt to classify services and suggest responsibilities for service procurement and delivery within a national electricity market.

An NGMC paper from November 1994 sets out the earliest available thinking on the subject of ancillary services in a national electricity market.[364] The NGMC's philosophy in that paper was that, wherever possible, markets in ancillary services would be run by the system operator:

> The objective of the electricity market is to increase economic efficiency through competition. In keeping with this objective, the level of services required to support the operation of the power system and their sourcing should be determined through market forces wherever possible. However, it is recognised that some aspects of these services can make this difficult to achieve. These include:
>
> - shared benefits can lead to free rider problems;

[364] *National Grid Management Council, National Electricity Market Project, Ancillary Services & Reserves*, Market Trading Working Group, (draft for comment) version 0.1, 15 November 1994.

> - provision of services may be difficult to quantify and monitor;
> - the service may be achievable by different mechanisms which are not directly comparable;
> - the requirement may be localised, with a local monopoly [in] its provision; and
> - fully market based provision of the service may be complex and not cost effective.
>
> As a result, pragmatic and less ideal arrangements may have to be considered in the interim and the level of service may have to be determined centrally rather than via market forces. The cost of each service provided may be determined by market forces or as a result of commercial negotiations between the service providers and the System Operator. In any commercial negotiations, the System Operator will examine the opportunity costs of various alternatives. The costs of providing these services should be shared on an equitable basis between all participants.[365]

Definitions of service categories inevitably evolved as the structure of a national market and its rules for operation were developed. The NGMC proposed the following as one possible categorisation of ancillary services:

- **System security**
  - system security control schemes (e.g. islanding, generator reduction control schemes); and
  - black start and restart capability.
- **Frequency control**
  - generator governor action;
  - automatic generation control (AGC);
  - automatic load shedding schemes (under frequency tripping); and
  - demand reduction schemes.
- **Voltage control**
  - generator reactive capability;
  - automatic load shedding schemes; and

365 Ibid., pp.2-3.

– generator network support.[366]

Although the NGMC work probably set the scene for future development of NSCS, no mechanisms for procurement and delivery were formalised at that stage.

NEM1 Phase 2, Ancillary Services Project

Following the initial efforts of the NGMC, the next significant step in the development and consolidation of ancillary services after the early draft stages of the NGMC Code of Conduct, was in a 1997 report for the NEM1 Phase 2, Ancillary Services Project.[367] This report established arrangements for the procurement of ancillary services prior to market start, the intention being for VPX and TransGrid to enter into ancillary service contracts that would be novated to NEMMCO on the commencement of the NEM. An extract from the report outlining the definition of services and the project objective is shown in Box E.1.

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366 Op. cit., p.7.

367 *NEM1 Phase 2 Ancillary Services Project Report, Recommendations for the procurement of ancillary services and for reimbursement by the market*, VPX and TransGrid, May 1997.

Box E.1: Extract from Ancillary Services Project Working Group report: definition of services and project objective

Definition of Ancillary Services in the context of NEM1 Phase 2

"Ancillary Services are those services performed by generation, transmission and control equipment which are necessary to support the transmission of electric power from producer to purchaser given the responsibilities of the operating authorities to maintain safe, secure and reliable operation of the interconnected power system.

The services include both mandatory services and services subject to competition."

Project Objective

The objective of the NEM1 Ancillary Services project is:

"To achieve a consistent set of arrangements for the procurement of and payment for the required Ancillary Services in line with the above definition which (in priority order):

1. will be practical to implement by July 199;

2. do not require significant investment in new monitoring hardware and/or IT facilities to administer;

3. provide adequate short and long term price signals to users and providers of the services; and

4. are capable of operating until NEMMCO has completed its review of the ancillary services arrangements in accordance with Clause 3.13.1 of the draft National Electricity Code."

With respect to support and control services, the report established sub-categories of ancillary services as follows:

- **Voltage control –** which includes services from:
  - generator unit reactive;
  - transmission plant reactive;
  - other reactive plant (e.g. hydro machines as SynCons, distributors and extra high voltage customers);
  - emergency load shedding schemes; and
  - on load tap changers on transformers.
- **Stability control** – which includes services from:

– excitation systems;

– power system stabilisers; and

– rapid generating unit unloading.

- **Network loading control –** which includes services from:

– automatic generation control (AGC);

– rapid generator unloading; and

– interruptible load shedding.

The recommendations that emerged from the Ancillary Services Project Working Group report formed the basis of Schedule 9G of the Code.[368] Schedule 9G articulated arrangements for procurement and cost recovery of all ancillary services:

- frequency control;
- voltage control;
- stability control;
- network loading control; and
- system restart.

Schedule 9G was deemed to be a more practical arrangement (than that in Chapter 3 of the Code) for the start of the NEM, and remained in place until the completion of the first ancillary services review.

E.4.1.2 Ancillary services post market start

The first ancillary services review

The first ancillary services review was a requirement of the Code as it existed at NEM-start:[369]

> (c) In conjunction with its obligations under clause 3.8.9(d), NEMMCO must investigate, consult with Code Participants in accordance with the Code consultation procedures and report to NECA within 2 years of market commencement on the possible development of market-based arrangements for the provision of ancillary services, including a short-term market in which Market

[368] A derogation of clause 3.11 in relation to acquisition, delivery and settlement of ancillary services. Schedule 9G was a Jurisdictional derogation that, in essence, sought to extend VPX / TransGrid pre-market arrangements, but also included some specific arrangements for Queensland.

[369] Clause 3.11.1. This review clause (with minor modifications regarding timetables) was included in the Code until version 5.6 was replaced by version 5.7 (Gazetted 9/8/01).

> Participants which are not parties to ancillary services agreements may submit offers for the provision of regulating capability or contingency capacity reserve.

The review to which the clause refers was completed in August 1999.[370] The report of the review made this general comment on the ancillary services arrangements that prevailed in the NEM's first two years:

> None of the parties most involved in the current arrangements finds them satisfactory. Contract negotiations for the initial round were protracted and difficult both for NEMMCO and the parties that responded to NEMMCO's invitation to tender. Generators feel they are unfairly and unreasonably required to provide too many services for free under the mandatory requirements of the Code and connection agreements. Retailers feel they are unfairly and unreasonably required to pay for all services, when they consider that they are not the cause of the requirement (although their customers may be). Many of these real or perceived problems are inherent to the central procurement of ancillary services overlaying a competitive energy market.[371]

With respect to recommendations for future arrangements for NCAS—that is, all ancillary services other than frequency control and system restart—the report of the review stated:

> Initial arrangements for voltage control (contingency and continuous) services are proposed as follows:
>
> - NEMMCO would remain responsible for the dispatch of voltage control services and for ensuring that there are sufficient voltage control services from a power system security perspective.
>
> - Contracts (for hedging/procurement) would be written between generators and TNSPs / NEMMCO depending on the clarification of responsibilities for reactive reserve.
>
> - For reactive generation that is required due to the connection of a generator and that is consequently specified in a connection agreement, no cost associated with reactive reserve. For reactive above this level, negotiated contracts that specify availability and enablement components. Compensation to be payable if generating plant needs to be backed off to provide the reactive service.
>
> - Although testing of an AC load flow nodal pricing model that would price reactive energy in the context of energy spot trading is proposed,

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370 *Evaluation of options for an ancillary services market for the Australian electricity industry, A project commissioned by the NEMMCO Ancillary Services Reference Group, Final Report*, Intelligent Energy Systems, August 1999.

371 Ibid. p.vii.

the co-dispatch of generator reactive capability with the energy spot market may not be warranted or feasible in the transitional phase.

Initial arrangements for Stability and Network Offloading [or network loading control] services are proposed as follows:

- Negotiated contracts are recommended as the most appropriate arrangement for procuring stability and network loading services for the foreseeable future.

- The arrangements would require NEMMCO to provide information on potential schemes and the service that they would provide. This would need to be included in the Statement of Opportunities.

- Further consideration of markets in NCAS should be preceded by a review of the basis for and structure of the currently defined generic (security) constraints applied in the SPD.[372]

The recommendations of this first review were (largely) implemented as proposed.[373] In response to the final item listed above, Code changes requiring further review of non-market ancillary services (the NCAS review) were made, with the insertion of a requirement in clause 3.1.4 of the Code[374] as follows:

(a1) *NEMMCO* must review, prepare and *publish* a report on:

…

(4) the provision of *network control ancillary services* including:

(i) a review of the responsibilities of *NEMMCO* and *Transmission Network Service Providers* for the provision of *reactive power support*;

(ii) a review of the formulation of those generic *network constraints* within *central dispatch* that are dependant on the provision of *network control ancillary services*; and

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372 Ibid. p.xiv.

373 NCAS continued to be procured on the basis of long-term contracts (per Schedule 9G of the Code) until a new NCAS tendering process [supported by new clause 3.11 in Version 5.7 of the Code (Gazetted 9/8/01) was implemented for NCAS contracts commencing 1 July 2002 and SRAS contracts commencing 1 July 2003.

374 Version 5.7 of the Code (Gazetted 9/8/01).

(iii) a program to assess the potential implementation of market mechanisms for the recruitment and *dispatch* of *NCAS*.

(a2) In conducting the reviews under clause 3.1.4(a1) …

(2) elements of the reviews set out under clauses … 3.1.4(a1)(4)(iii) must take into consideration the results of the [*NECA* report that analyses the outcome of trade in *market ancillary services* through the *spot market*.]

The ACCC's authorisation of the Code changes incorporating the NCAS review indicated:

> … the Commission notes a number of reviews may impact upon the future provision of NCAS, including:
>
> - the review of the integration of network services and energy markets [aka NECA's review of the integration of energy markets and network services (RIEMNS)];[375]
> - the market and system operator review [aka the Market and System Operator Review Committee (MSORC) process];[376]
> - the Code change process arising from the network pricing review [aka NECA's transmission and distribution pricing review]; and
> - the review of the treatment of constraints in the market.
>
> … in relation to NCAS the ancillary services review will need to encompass the outcomes of the other reviews listed above, and in particular the outcomes of the MSORC.
>
> The MSORC is considering the most appropriate allocation of roles between NEMMCO, as the system operator, and TNSPs as service providers. The outcome of this review will determine which agency should be responsible for procuring NCAS, dispatching NCAS, recovering the costs of NCAS and determining the most appropriate methodology for recovering the costs.

[375] See section below.

[376] See section below.

> … in terms of timing, any review considering possible market arrangements of future development for NCAS will have to commence after the outcomes of other relevant reviews are known.

The RIEMNS and MSORC process are discussed further in following sections.

The reference to "the review of the treatment of constraints in the market" was probably a reference to either or both of: the NEMMCO review on formulation of intra-regional constraints;[377] or the IES review on optimising combined secure and economic dispatch, conducted on behalf of the Reliability Panel.[378] Each of these reviews was scheduled for around that time. The outcomes of these reviews had no apparent impact on fulfilment of TNSP/NEMMCO responsibilities for NSCS.

The requirement to conduct an NCAS review per Clause 3.1.4(a1)(4) remains in the current version of the National Electricity Rules, although the review referred to has yet to commence for the following reasons:

- the review of network control ancillary services alluded to in clause 3.1.4(a1)(4) had to take account of the NECA report alluded to in clause 3.1.4(a2)(2)—a final version of this NECA report was not released prior to NECA being disbanded;[379] and

- given the possibility of NEMMCO's NCAS review overlapping with the considerations of our CMR, NEMMCO sought and received our agreement to delay the commencement of the NCAS review until such time as the CMR was able to provide some guidance as to appropriate direction.

The RIEMNS process

The review of the integration of energy markets and network services (RIEMNS) resulted in a report[380] that did not impact in any substantial way on the development of network support and control services, although RIEMNS did touch on a couple of issues relating to the management of network congestion:

- provision of network outage information to the market by TNSPs; and

- a proposal for NECA to develop a network performance framework.

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[377] See NEMMCO (Network Constraints Reference Group), *Formulation of intra-regional constraints, Issues and options paper*, Version No. 2 (January 2002) available at: http://www.ksg.harvard.edu/hepg/Papers/Nemmco%201-02%20trans%20price%20148-0061.pdf.

[378] Intelligent Energy Systems (IES), *Optimising combined secure and economic dispatch, Report to the Reliability Panel* (February 2003).

[379] This report on frequency control ancillary services has subsequently been made available – see NECA, *Review of market ancillary services*, Final report (June 2004), available at: http://www.nemmco.com.au/ancillary_services/160-0287.pdf.

[380] NECA, *The scope for integrating the energy markets and network services, Stage 1 final report*, August 2001. No subsequent stages of the RIEMNS process were undertaken.

Code changes requiring TNSPs to provide network outage information were authorised. However, the ACCC considered that NECA's proposed network performance framework duplicated powers already vested in the ACCC.[381] Consequently, the ACCC did not authorise NECA's proposed Rule changes on the development of a network performance framework.

The MSORC process

The report of the MSORC was expected to be a key element in the evolution of responsibilities for ancillary services. The NEM Governance and Liability Steering Committee, comprising the NEM jurisdictions and the Commonwealth, established MSORC in late 1999/early 2000 to assist the Steering Committee to, *inter alia*:

> address governance issues, including … the allocation of responsibilities for MSO System Security and System Operation functions between NEMMCO and the TNSPs.[382]

With respect to allocation of responsibilities for network control, the members of MSORC were unable to reach agreement. The report noted:

> Although it is not a core issue for the MSORC review, the MSORC has given some consideration to the allocation of responsibilities between NEMMCO and the TNSPs regarding the procurement, scheduling, dispatch and funding of NCAS in the NEM.
>
> The MSORC finally resolved to put this issue to one side because a final decision on it would not change any other MSORC recommendations. The MSORC notes that current code change proposals before the ACCC call for NEMMCO to undertake a further review of this issue during 2001. It is suggested however that before NEMMCO can reasonably be expected to find a satisfactory resolution to this issue, it will need some policy decisions in the form of much clearer regulatory principles and guidelines from the jurisdictions and/or the ACCC concerning the future scope of TNSPs' regulated network services.[383]

The recommendations of the MSORC report were never implemented.

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381 See ACCC, *Determination: Stage 1 of integrating the energy market and network services* (October 2002), available at: http://www.accc.gov.au/content/trimFile.phtml?trimFileName=D03+15425.pdf&trimFileTitle=D03+15425.pdf&trimFileFromVersionId=756520.
The recently commenced reporting of total constraint cost measures by the AER is a second generation manifestation of the "powers already vested in the ACCC".

382 From the MSORC terms of reference, *System Security & System Operation Review Report 1 (Final Draft) System Operator Functions & Responsibilities*, December 2000, Appendix 1.

383 Ibid, p.11.

NECA report on generator rebidding

The next change in the network control ancillary services environment came with a requirement for NEMMCO to use NCAS to increase the benefits of trade from the spot market. The requirement arose in the context of Code changes designed to address concerns regarding generator rebidding behaviour.

NECA's inquiry into rebidding resulted in a 2001 report[384] that included some proposals for tackling short-term price spikes and for removing opportunities for generators to exploit inefficiencies arising from: transfer limits across interconnectors; short-term loading constraints; dispatch processes; and network services. With respect to these inefficiencies the report said:

> Our evidence to the South Australian electricity taskforce[385] drew attention to four specific examples of these sorts of inefficiencies and to the need to take urgent action to improve the operation of the market in order to remove the opportunities they create for generators to exploit those inefficiencies:
>
> **efficiency of dispatch**. The draft report of our review of the scope for integrating the energy market and network services pointed to the tendency for constraint equations to be written relatively to favour local generation. This is the case, for example, in relation to Ladbroke Grove in South Australia and generators in south-east Queensland. This arguably breaches one of the fundamental objectives of the market, set out in the Code, that intrastate trading should not be treated more or less favourably than interstate trading. It can, and does, lead to relatively more expensive plant being dispatched even where cheaper electricity would have been available for import across an interconnector. NEMMCO recently established a reference group to address these issues. That group should report urgently. Its focus should be on ensuring the essential integrity of the fundamental anti-discriminatory objective of the Code and the objective of maximising the benefits of trade. To the extent that meeting any second-order technical obligations imposed by the Code conflicts with fulfilling that overriding objective, those technical obligations should be rewritten. A common complaint from participants is the perceived complexity of the constraint equations, in part as a result of inconsistent formulation. Work is required to increase the quality of constraints to enhance the usability of this critical information; and
>
> **network services**. We believe there is scope within the existing arrangements for NEMMCO to make more use of, for example, load shedding, real and reactive support and scheduling, and unit commitment contracts. Network services, including pre-emptive unit commitment contracts and real-time ancillary services, could be developed to help to cope with the consequences

384 NECA, *Generators' bidding and rebidding strategies and their effect on prices*, Report, July 2001.

385 The SA Government established the South Australian National Electricity Market Taskforce in March 2001 to assess the impact of the National Electricity Market (NEM) on business and domestic customers in South Australia.

of interconnector constraints. The recently-established gatekeeper project is working towards possible solutions to some of these issues. The extent of NEMMCO's current power to enter into such contracts is, however, uncertain. We therefore recommend a change to the Code to give NEMMCO clearer and wider powers to enter into such contracts.

NEMMCO should take the most urgent possible action to address these inefficiencies. The changes we recommend to the Code will help facilitate that action.[386]

As a consequence of the NECA report and subsequent application to amend the Code, the ACCC authorised a change to clause 3.11.3(b) of the Code as follows (insertions from version 7.5 are underlined):

> *NEMMCO* must develop and *publish* a procedure for determining the quantity of each kind of *non-market ancillary service* required for *NEMMCO*:
>
> (1) to achieve the *power system security and reliability standards*; and
>
> (2) 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*.[387]

This revised clause is retained in the current Rules (now renumbered as 3.11.4).

E.4.1.3 Current arrangement for the management of interconnector transfer capability

At present, where interconnector capability is managed, it is managed by NEMMCO; but this applies to only two of the NEM's five interconnectors—Snowy to New South Wales and Victoria to Snowy. Arguably, these cases represent a "legacy assignment" of responsibilities, dating back to the start of the market in 1998. Transfer capability on the VIC-SA and QNI links is not actively managed by NEMMCO or the respective TNSPs.

However, there are likely to be strong commercial incentives on Basslink's asset owner to effectively manage the transfer capability of the DC link, given it is an MNSP whose income stream depends (in part) on the available capacity of the link.

The procedure governing how NEMMCO manages transfer capability on the Snowy to New South Wales and Victoria to Snowy interconnectors is described below.

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[386] NECA, *Generators' bidding and rebidding strategies and their effect on prices*, Report, July 2001.

[387] Clause 3.11.3(b)(2) first appeared in Version 7.6 of the Code (Gazetted 16/1/03) and remains in the current version of the Rules.

First, NEMMCO sources reactive support from Snowy Hydro generators, which operate in Synchronous Condensor (SynCon) mode. When operating in SynCon mode, Snowy Hydro's generators either inject or absorb reactive power (MVArs), which is used by NEMMCO to manage the voltage level drop along the long interconnection between Melbourne and Sydney. Without this SynCon service, the interconnectors' transfer capabilities would be substantially lower unless TransGrid and VenCorp invested substantial capital in the provision of alternative, network-based sources of reactive power and voltage control.

Prior to the start of the NEM, the reactive power support for both of these interconnectors was managed by the State Electricity Commission of Victoria (SECV) via a contract with Snowy Hydro Trading Pty Ltd. The SECV probably did this as part of its management of Victoria's electricity entitlements under inter-governmental agreements on the Snowy Mountains Hydro Electric Scheme.[388] The SECV's creation of the Victorian Power Exchange (VPX), a market and system operations arm, resulted in responsibility for managing the reactive support contracts passing to VPX. At the start of the NEM in December 1998, NEMMCO took over the functions of VPX, and as a consequence responsibility for the interconnector support contracts passed to NEMMCO.[389]

There does not appear to have been any consideration of whether, in the long-term, TNSPs or NEMMCO would be the more appropriate party to manage the reactive support contracts, having regard to the incentives on TNSPs versus NEMMCO. The purpose of the report was solely to establish savings and transitional arrangements for ancillary services to be managed once the NEM started. These interim arrangements were to be reviewed by NEMMCO within two years of market start (as specified in Clause 3.13.1 of the draft National Electricity Code).[390] The report recommended temporary arrangements, such that NEMMCO would be the counter-party to ancillary service contracts entered into by TransGrid/VPX, following the novation of the contracts to NEMMCO on market start. Arguably, the increased power transfer capability through the Snowy region ultimately provides reliability of supply benefits to customers in the importing region(s), a principle recognised by market designers before market start in 1998.[391]

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388 *Snowy Mountains Hydro-electric Agreements Act 1958 No.20 (NSW).*

389 See TransGrid & VPX 1997, "*National Electricity Market (NEM1, Phase 2) — Recommendations for the Procurement of Ancillary Services and for Reimbursement by the Market*", for TransGrid and Victorian Power Exchange, by NEM1 Ancillary Services Project, May 1997, p. ix, "Transition to NEMMCO Management"; Appendix C, Attachment 2, items 6 (Synchronous condensor spinning reserve); Table 4.2.2.2; and Appendix D, sections 2.2.1 and 2.2.2.

390 NEMMCO's 1999 Ancillary Services review recommended the establishment of markets for Frequency Control Ancillary Services (FCAS) and a further review of arrangements for Network Control Ancillary Services (NCAS). To date, the basic NCAS arrangements remain unchanged from those established at market start. Two other reviews — RIEMNS and MSORC — each failed to address reforms to NCAS.

391 This beneficiary pays principle appears to have been recognised both as a general principle (*ibid*, p.5) and in the way reactive power expenses were to be recovered on a location specific basis *(ibid*, p.13). Specifically, appears that a form of Cost Reflective Network Pricing (CRNP) was used to recover the unbundled costs of providing reactive support — "MVAr demand charges to

Second, NEMMCO procures a network loading control service for imports along the Snowy-VIC directional interconnector, which involves arming a Victorian smelter to trip. This network loading control scheme can raise the maximum secure Snowy-VIC transfer limit by 200 MW (currently from 1 700 MW to 1 900 MW) and is of most value (and generally only utilised) when there are potential shortfalls in supply in VIC-SA during periods of high demand.[392] Like the reactive support service discussed above, prior to the start of the NEM the SECV and then VPX contracted for this load-tripping service, with the responsibility for the contract assigned to NEMMCO at market start, where it has remained.[393] Importantly, this smelter load-tripping scheme primarily provides reliability benefits rather than security benefits. To understand this, it is worth considering that in the absence of the load-tripping scheme, NEMMCO could still operate the network securely at the lower Snowy-VIC transfer limit, but this could result in involuntary load shedding in Victoria and South Australia (with resulting VoLL pricing). The system would still be secure in this case, but at the cost of some lost load in VIC and SA. Arguably, it is customers in Victoria and SA who are the principal beneficiaries of the increased reliability arising from the increase in secure transfer capability of the Snowy-VIC interconnector.[394] If this is accepted, it can be argued that the Victorian and South Australian TNSPs should be responsible for procuring the smelter load-tripping service, rather than NEMMCO.

E.4.2 Current approach to service delivery

This section focuses on the current environment for NSCS and outlines:

- the definition of relevant NSCS, the rationale for their procurement, and how they work;
- the guidance provided to TNSPs and NEMMCO in determining what type and how much NSCS should be procured and delivered; and
- some stylised examples of NSCS.

E.4.2.1 Service definition and rationale

NSCS currently procured and delivered include:

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distributor based on 10 highest reactive demands at each wholesale metering point" (ibid, Table 4.2.2.2).

392 Arming the smelters for rapid off-loading enables the (higher) 5-minute thermal limits on the Victoria-Snowy interconnector to be used in dispatch. This network loading control scheme is only used under lack of reserve level 2 (LOR2) conditions, as defined in clause 4.8.4(r) of the Rules, and after NEMMCO has assessed if there is an economic benefit from enabling the service.

393 *ibid*, p. ix "Transition to NEMMCO Management" and Appendix C, Attachment 2, item 8 (Interruptibility service) deals specifically with the smelter tripping service. See also Table 4.2.2.3; and Appendix D, section 2.2.3 of the same report.

394 This beneficiaries pay principle was explicitly acknowledged in Table 4.2.2.3 of TransGrid & VPX report, which states that the recovery costs relating to the smelter rapid unloading scheme is to be based on "CRNP to beneficiaries (charges to distributors)".

- **Network support services**—procured by TNSPs via contracts with third parties (network support agreements or NSAs) via services in the form of:
  - generators agreeing to be constrained-on or -off;
  - loads agreeing to be constrained-on or -off;
  - generators providing reactive power capability (see Box 2), either as a condition of a network connection agreement or under a separate contract;
- **Network control services**—delivered by TNSPs from their own infrastructure as reactive power capability in the form of voltage control from:
  - capacitor banks and reactors;
  - static Var compensators (SVCs);
- **Network control ancillary services (NCAS)**—procured by NEMMCO via contracts with Market Participants (not TNSPs) as either:
  - reactive power ancillary service in the form of voltage control from:
    - generators operating in generation mode;
    - generators operating in synchronous condensor mode (SynCons)[395]; and
    - DC links;
  - network loading control ancillary service—provided via:
    - generator control schemes, for example rapid generator unit loading or rapid generator unit unloading; and
    - load tripping schemes.

[395] Generators operating in SynCon mode do not produce MWs – they operate as a motor (with small or negligible load on the power system), but retain the ability to inject and absorb MVars.

Box E.2: A note on reactive power

Delivery of real power (MWs) and delivery of reactive power (MVars) are complementary services—the power system cannot be effectively operated without control over both MWs and MVars. Control over reactive power injection or absorption is necessary to manage voltage levels at specific locations in a network. Voltage stability is a key form of constraint on the operation of the power system.

Reactive power capability can be delivered via several different technologies.

Dynamic reactive power capability is the ability to change the level of MVar injection or absorption in response to emerging real-time power system conditions. Dynamic reactive power capability can be provided by: generators in generation mode; generators in SynCon mode; SVCs; and DC links.

Static reactive power capability is the ability to inject or absorb MVars at a given level depending on whether the relevant plant is switched on. Static reactive power capability can be provided by: capacitor banks (injecting MVars); and reactors (absorbing MVars). Static reactive plant can be configured to switch automatically in response to network voltage changes.

Voltage stability constraint equations in NEMDE reflect the availability of plant with reactive power capability. When the availability of reactive plant changes, so too will the RHS limits of relevant constraint equations in NEMDE. As RHS limits on constraint equations change, network congestion can be relieved or exacerbated.

Aside from procuring and delivering different forms of NSCS, TNSPs and NEMMCO employ differing rationales for delivering or contracting NSCS:

- TNSPs ensure appropriate levels of NSCS are delivered such that there is the capability to manage intra-regional network reliability at expected peak demand in an effort to meet "intra-regional reliability" obligations.

- TNSPs could procure and deliver NSCS as part of the most efficient package of measures to deliver network capability with net market benefit consistent with the market benefits limb of the Regulatory Test.

- NEMMCO procures appropriate levels of NCAS such that there is the capability to ensure a system-wide secure and reliable network at all times as part of meeting the power system security and reliability standards under the Rules.

- NEMMCO may procure NCAS to assist in maximising the value of spot market trading.

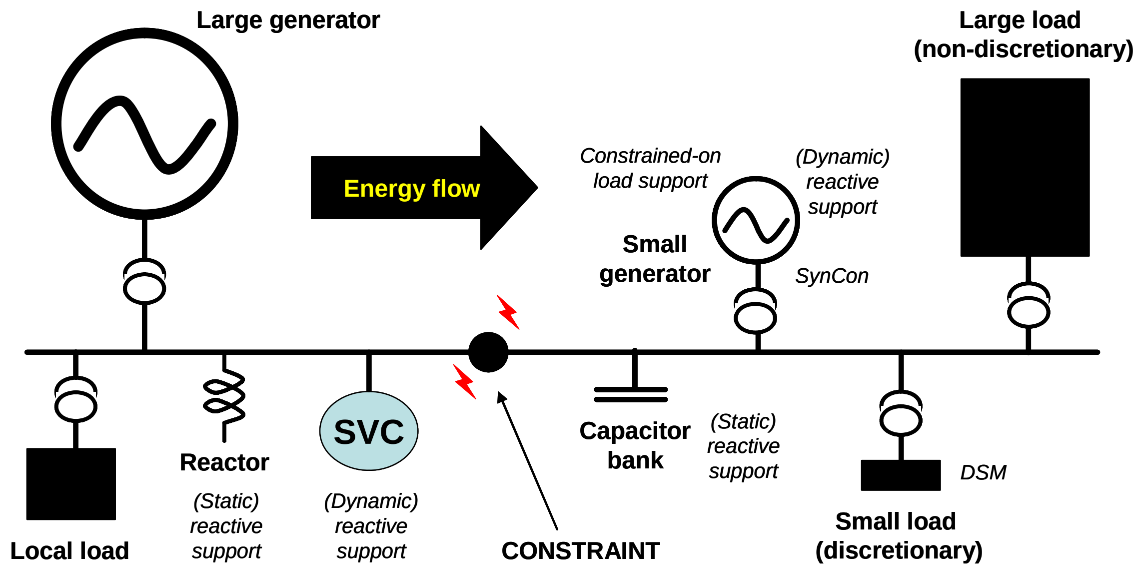
As indicated previously, although various legislative instruments and obligations package TNSP and NEMMCO responsibilities in different ways, the services that

TNSPs and NEMMCO procure and deliver and the outcomes that they seek to achieve are in many ways indistinguishable.

E.4.2.2 How support & control services work

Delivery of network capability can be accomplished with a variety of technologies and combinations of technologies. Most of the requirements for NSCS are highly locationally specific and, by varying the level of real or reactive power at different locations in the network or by operating load control facilities, the level of network congestion can be altered in ways that either reduce or increase the dispatch cost on the spot market for energy. Examples of network infrastructure and NSCS that can be used to facilitate network flows are depicted in Figure E.7.

Figure E.7 Stylised network with infrastructure and support & control services to facilitate network flows



In the stylised network depicted in Figure E.7 energy typically flows from left to right even though there is a constraint in the middle of the network. Constraints are commonly of two forms:

- *thermal limit*—limitation on the amount of heating that network elements can withstand, controlled by increasing or reducing real power (MWs) loading on a specific side of the constraint; and
- *stability limit*—limitation on the ability of network infrastructure to dampen/withstand unanticipated fluctuations in the power system, controlled

by injecting or absorbing reactive power (Vars) at a specific location in the network.

Depending on the constraint form ("thermal" or "stability") and network loading conditions, the constraint could be relieved in a variety of ways as noted in Table E.1.

Table E.1: Use of NSCS technology by either TNSPs of NEMMCO

Technology	Under current arrangements …
Capacitor bank providing static voltage support as MVar injection.	• technology is TNSP owned and controlled – not available to be contracted by NEMMCO.
Reactor providing static voltage support as MVar absorption.	• technology is TNSP owned and controlled – not available to be contracted by NEMMCO.
Static Var compensator (SVC) providing dynamic voltage support – MVar injection or absorption.	• technology is TNSP owned and controlled – not available to be contracted by NEMMCO.
Small generator discretionally controlled to provide: • network support by being "constrained-on"; • dynamic voltage support – MVar injection or absorption – while either: o operating in generation mode; or o operating in SynCon mode.	• constrained-on network support contracted by TNSPs. • voltage support from generators in generation mode contracted by both TNSPs and NEMMCO. • voltage support from generators in SynCon mode contracted by NEMMCO.
Small load providing demand-side management (DSM) as either: • pre-contingent network support (e.g. enabling / arming the rapid unloading of a smelter); or • post-contingent network support (e.g. utilising the rapid unloading of a smelter).	• network load relief services are contracted by both TNSPs and NEMMCO.
"Build out" the constraint via upgraded transmission lines or transformers.	• option only available to TNSPs.

E.4.2.3 Services procured or delivered by TNSPs

Guidance to TNSPs

The mix of assets and the form of NSCS that an TNSP supplies with its own infrastructure, or procures via contract with third parties, will be a function of the relevant standards associated with preventing or managing congestion occurring in the network for each TNSP and the testing of available options through the Regulatory Test.

The standards to be met by each TNSP are unique to that TNSP, and may include:

- requirements outlined in state-based legislation;
- licence conditions imposed by jurisdictional regulators (or ministers);
- technical requirements included in the Rules;
- standards agreed with connected customers;
- formal (and informal) internal long-term planning documents;
- formal (and informal) internal operational and maintenance planning documents;
- standards imposed via regulatory resets conducted by the AER; or
- standards imposed by Standards Australia, or other relevant international standards.

This suite of documentation (listed above) will be collectively referred to here as "TNSP network capability obligations". Any combination of one or more (or even all) of the above may state (or suggest) a need to procure NSCS to ensure the appropriate "standard" is not breached.

Although Network Service Provider obligations are commonly referred to in the context of "reliability", TNSPs must also ensure that supply is robust to credible contingencies, indicating that TNSPs must also consider "security" as a factor. Hence the distinction between reliability and security does not represent a boundary of TNSP responsibility, and so "TNSP network capability obligations" is the preferred generic reference.

Note that the costs of the services procured by TNSPs as support and control services are recovered via their regulated revenues.

Determining the level of procurement

Setting aside (for the moment) procurement of NSCS for purely "market benefit" reasons, the appropriate level of procurement of NSCS is not always straightforward to determine.

Where TNSP network capability obligations are relevant[396], the level of NSCS procured or delivered by a TNSP will depend on the TNSP's interpretation of the applicable instrument(s) and on the mix of infrastructure and services by which the TNSP meets the relevant standard. Subject to funding restrictions established via regulatory resets, there is a degree of flexibility with respect to the mode by which TNSPs will choose to deliver on network capability obligations. The choice is between:

[396] That is, the "market benefits" limb of the regulatory test does not apply.

- new or augmented TNSP owned infrastructure:
  - transmission lines or transformers; or
  - reactive power capability in the form of:
    - capacitor banks or reactors; or
    - static Var compensators (SVCs);
- network control mechanisms using the TNSP's infrastructure (e.g. splitting/switching schemes that deliberately break a point of connection between network elements to increase network capability at the cost of a probabilistic loss of network reliability); and
- network support services procured by TNSPs via contracts with third parties in the form of:
  - generators agreeing to be constrained-on or -off;
  - loads agreeing to be constrained-on or -off; or
  - generators providing reactive power capability.[397]

Where the "markets benefits" limb of the Regulatory Test is applied, some mix of any or all of the above modes for delivery of network capability is also likely to be appropriate, the optimal mix being that which maximises net market benefit.

E.4.2.4 Services procured by NEMMCO

Guidance to NEMMCO

NEMMCO's obligations with respect to procuring NCAS are most clearly expressed in clause 3.11.4(b) of the Rules, which states:

> NEMMCO must develop and publish a procedure for determining the quantity of each kind of [network control ancillary service][398] required for NEMMCO:
>
> (1) to achieve the *power system security and reliability standards*; and

[397] Dynamic voltage support (MVar injection or absorption) either as part of the amount a generator is required to make available as a condition of its connection agreement with the NSP; or as a separately contracted amount in addition to that available via connection agreements.

[398] Clause 3.11.4(b) actually refers to "non-market ancillary services" that comprise both *system restart ancillary services* (SRAS) and *network control ancillary services* (NCAS). Procurement of SRAS is not relevant to this paper.

(2) 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*.

The formal descriptions of NCAS are provided in NEMMCO's amended procedure for determining quantities of network control ancillary services.[399] The two types of NCAS identified by NEMMCO are described in those procedures as follows:

> **Reactive power ancillary service** [RPAS] is the capability to supply reactive power to, or absorb reactive power from, the transmission network in order to maintain the transmission network within its voltage and stability limits following a credible contingency event but excluding such capability within a transmission or distribution system or as a condition of connection.
>
> and
>
> **Network loading control ancillary service** [NLCAS] is the capability of reducing an active power flow from a transmission network in order to keep the [electrical] current loading on interconnector transmission elements within their respective ratings following a credible contingency event in a transmission network.

NEMMCO's choices in the procurement of NCAS are limited because of:

- clause 3.11.5(a) of the Rules, which states:

  "… NEMMCO must call for offers from persons who are in a position to provide the *non-market ancillary service* so as to have the required effect at a connection to a *transmission network* in an invitation to tender."

- clause 3.11.5(j) of the Rules, which states:

  "… NEMMCO must not acquire non-market ancillary services from any person who is not a Registered Participant."

- the RPAS description (noted above), which is qualified as:

  "excluding such capability within a transmission or distribution system"

thus excluding TNSPs from tendering for "residual" NCAS to NEMMCO.

[399] See http://www.nemmco.com.au/ancillary_services/168-0021.pdf.

Therefore, NEMMCO can only acquire NCAS from Registered Participants who are neither transmission NSPs nor distribution NSPs. The consequence is that provision of NCAS in the form of reactive power capability is in effect limited to:

- registered generators operating in generation mode;
- registered generators operating in SynCon mode; and
- MNSPs providing DC link voltage control.

Note that the costs of the services procured by NEMMCO as NCAS are recovered via a levy on all Market Customers in proportion to their energy use.

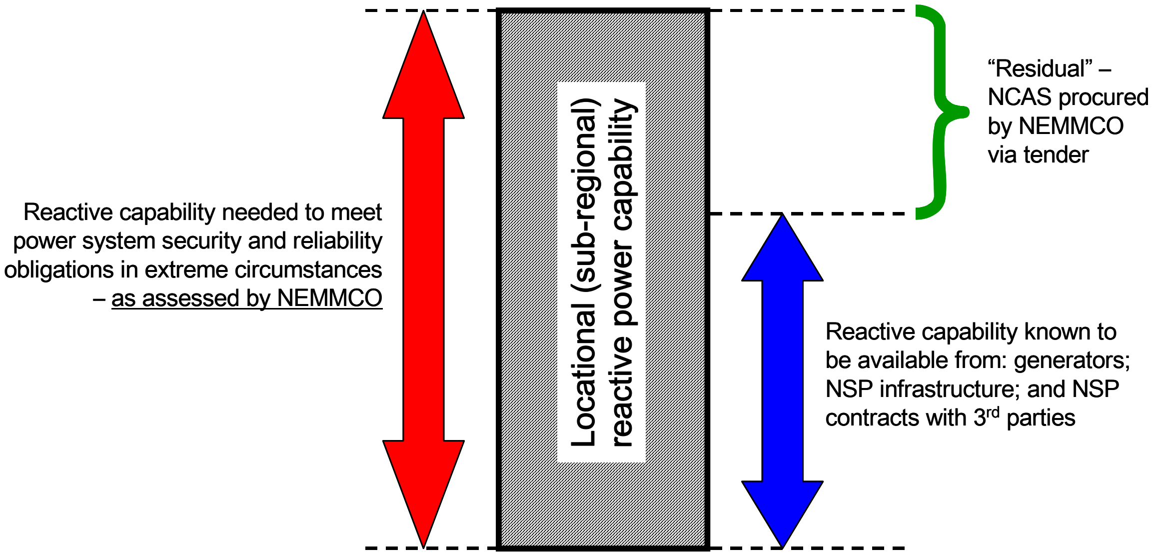
E.4.2.5 Determining the level of procurement

Power system security and reliability

NEMMCO's role in ensuring that appropriate levels of network support and control service are available to achieve the *power system security and reliability standards* may be seen as that of a "procurer of last resort"; in the absence of NEMMCO procurement of NCAS, the power system could experience either security or reliability problems.[400]

[400] NEMMCO anticipates the need for support & control services into the medium term. In the past, NEMMCO has contracted for NCAS on two-year time frames.

Figure E.8 Schematic representation of NEMMCO's reactive power capability procurement decision



With respect to NCAS in the form of reactive power capability, the volume procured by NEMMCO on a locational (sub-regional) basis is currently determined as the residual between (see Figure E.8):

- total capability required to manage power system security and reliability in either "peak loading conditions" or "low loading conditions";[401] and
- the capability guaranteed to be available through the combination of:
  - TNSPs (own infrastructure and contracts with third parties); and
  - generators delivering on performance standards specified in connection agreements between generators and TNSPs.

In making assessments as to the nature of the residual requirement, NEMMCO is therefore highly reliant on information provided to it by TNSPs.

[401] Peak loading conditions are normally associated with high summer and air-conditioning loads. Low loading conditions are those normally associated with overnight and/or weekend loads. For formal description of the reactive power requirement, see NEMMCO's *Amended procedure for determining quantities of network control ancillary services* [section 4.3, p.5], which can be found at http://www.nemmco.com.au/ancillary_services/168-0021.pdf.

Increasing the benefits of trade from the spot market

NEMMCO's obligations with respect to increasing the benefits of trade from the spot market are mentioned only in the (heavily qualified) Rule clause 3.11.4(b)(2), in which NEMMCO is required:

> 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*.

The degree of qualification in this clause (underlined) gives a large amount of discretion to NEMMCO as to how the requirements of the clause are to be met.

NEMMCO has not yet conducted tenders for NCAS with the specific intent to procure services to increase the benefits of trade from the spot market. However, where NEMMCO has procured NCAS for the purpose of achieving the *power system security and reliability standards*, and those services can be deployed to increase the (net) benefits of trade from the spot market, NEMMCO will deploy NCAS for the (net) benefit of the market.

NEMMCO gives effect to clause 3.11.4(b)(2) by deploying both NLCAS and RPAS. Each of these services increases the secure (post-contingent) network capability of interconnectors and thus increases the ability of the dispatch process to replace high-cost generation in one region with low-cost generation from an adjoining region.

E.4.2.6 Stylised examples

The following examples outline the types of services that can be procured by either TNSPs or NEMMCO in fulfilling their respective NSCS obligations.

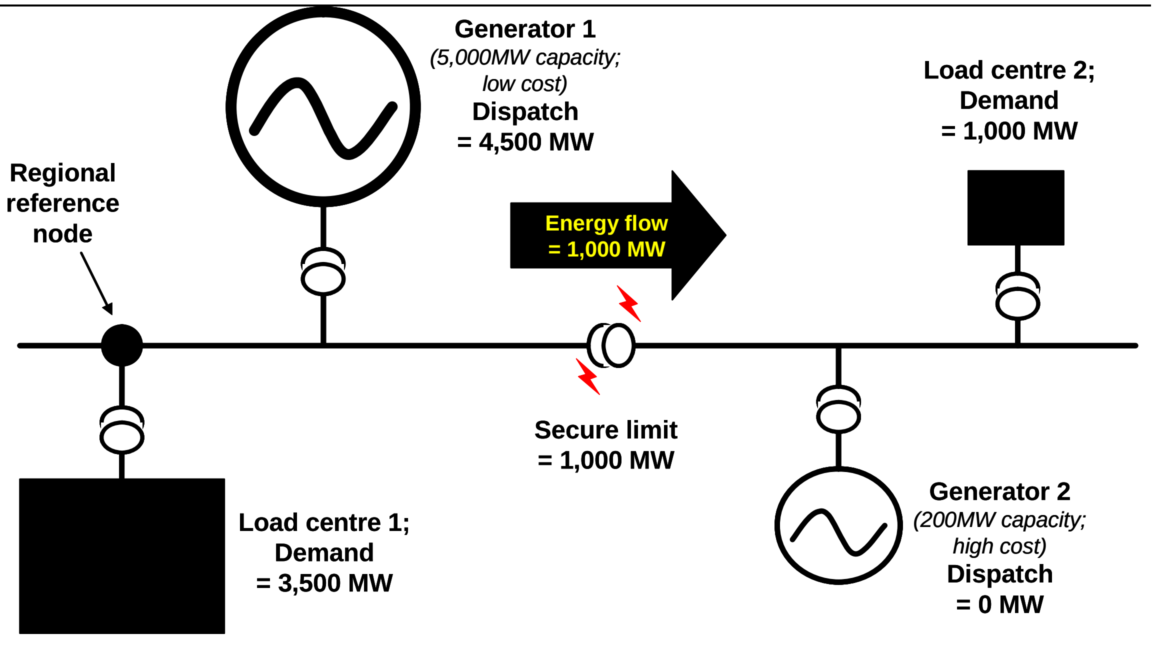
Constrained-on generation

This example illustrates the use of constrained-on generation as a mechanism to relieve loading on a critical transmission element.

- Power flow within the region depicted in Figure E.9 is constrained by a thermal limit on a transformer, such that flow is restricted to ≤ 1 000 MW from left to right. Demand and generation patterns within a region are initially such that low-cost Generator 1 is able to service all load within the region without network loading constraints being breached.
  - Total regional load is 4 500 MW [3 500 MW at Load centre 1; and 1 000 MW at Load centre 2].
  - Low-cost Generator 1 is dispatched at 4 500 MW and high-cost Generator 2 is not dispatched.

– Loading on the transformer subject to the constraint is at its secure limit of 1 000 MW.

Figure E.9 Initial network loading patterns—generation not constrained



- System conditions change, with a 200 MW increase in demand at each of Load centre 1 and Load centre 2. Total demand rises to 4 900 MW.

- In the absence of network constraints, total network loading is within the capability of low-cost Generator 1, but dispatch of 4 900 MW from Generator 1 (with no support from Generator 2) would breach the constraint on power flow through the transformer in the middle of the network by 200 MW. The choice is either to reduce demand (shed load) at Load centre 2 or dispatch Generator 2 to relieve the constraint on the transformer in the middle of the network.

- With network support available from Generator 2 (see Figure E.10):

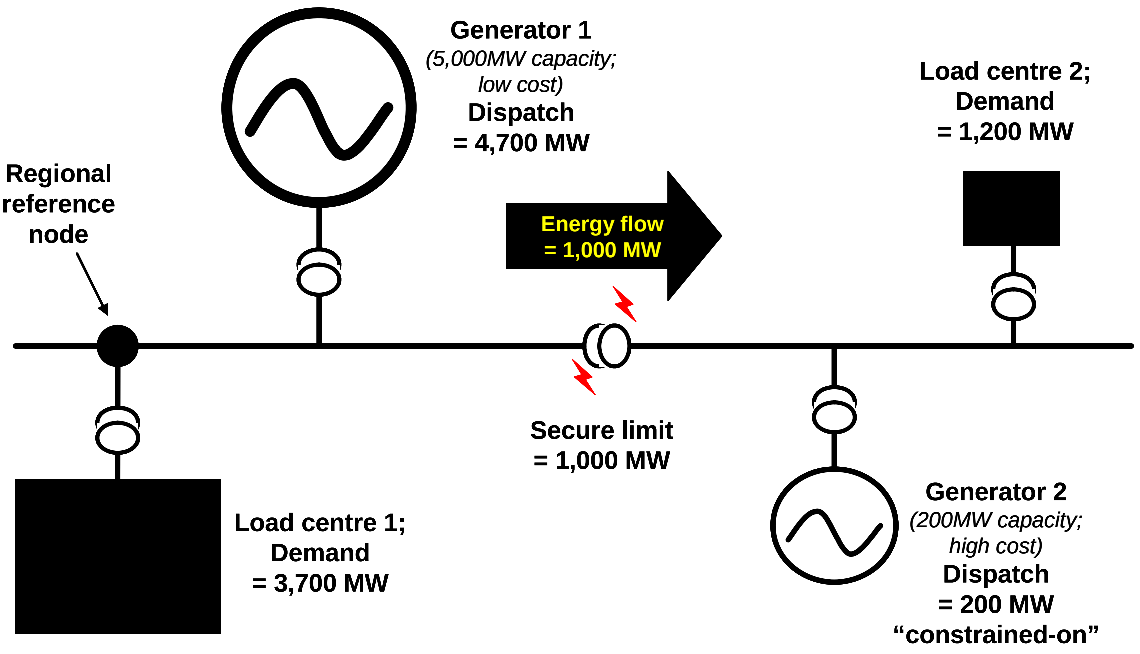
  – Total regional load is 4 900 MW (3 700 MW at Load centre 1, and 1 200 MW at Load centre 2).

  – Low-cost Generator 1 is dispatched at 4 700 MW and high-cost Generator 2 is dispatched at 200 MW.

  – Loading on the transformer subject to the constraint is at its secure limit of 1 000 MW.

As the RRP is established by the cost of meeting an increment of load at the regional RRN, the Generator 1 (low marginal cost) offer will set the price. If all generators are offering their output at marginal cost, Generator 2 (high marginal cost) will need to be constrained on. In the absence of some constrained-on payment (via a network support agreement or other mechanism), Generator 2 is likely to bid at or near VoLL or bid itself unavailable.

Figure E.10 Subsequent network loading patterns—generation constrained-on



Deployment of reactive power support (SynCons)

Figure E.11 illustrates the use of voltage support to increase power transfer capability. Although the example makes reference to transfers across region boundaries, it is equally applicable to circumstances where no region boundary is involved.

- In the absence of dynamic reactive power support, interconnector flow from Region A to Region B is limited to only 500 MW by voltage stability considerations. With reactive power support from G_{B3} operating in SynCon mode, interconnector flow from Region A to Region B can rise to 1 000 MW (see Figure 5).

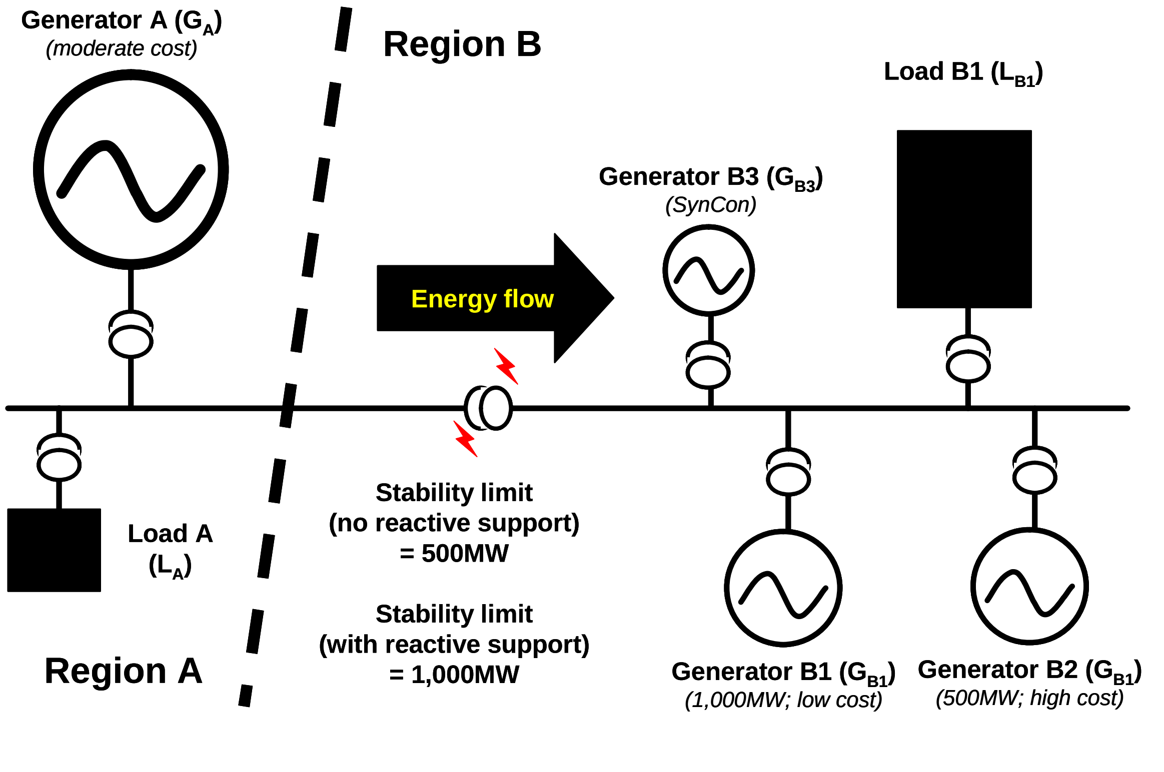
- If Region B load is 1 450 MW, optimal dispatch is 1 000 MW from (low cost) G_{B1} and 450 MW across the interconnector from Region A. There is no need to deploy reactive power support from G_{B3}.

- If Region B load rises beyond 1 500 MW, G_{B1} will be dispatched to its 1 000 MW limit and either:

– in the absence of reactive power support from G_{B3}, interconnector flow will be limited to 500 MW, with high-cost generator G_{B2} being dispatched to pick up the remaining supply deficit; or

– with reactive power support from G_{B3}, interconnector flow will be increased to (up to) 1 000 MW, with high-cost generator G_{B2} only being dispatched if Region B load rises beyond 2 000 MW. (This assumes generation from G_{B3} is high cost, but operating G_{B3} in SynCon mode is very low cost).

Figure E.11 Deploying SynCons to manage voltage stability limit



Deployment of load tripping scheme

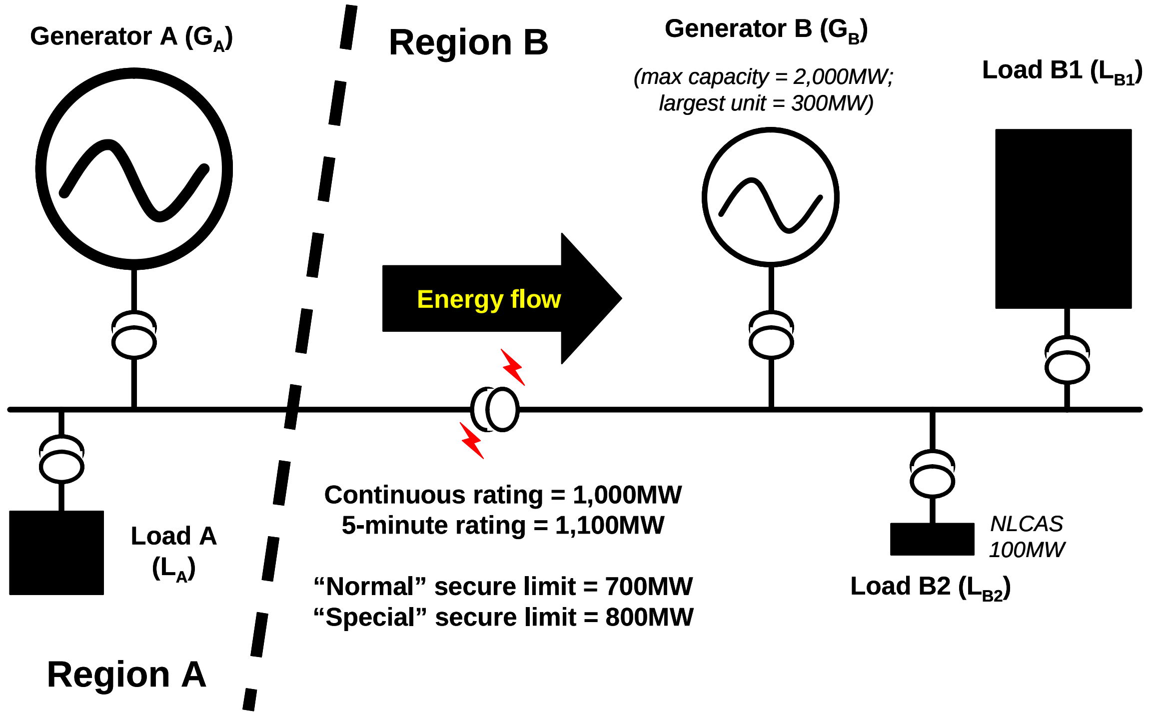
Figure E.12 illustrates the use of a load-tripping scheme, although the principles outlined may also be translated to rapid-response generators.

- Under "normal" conditions, local load (in Region B) of up to 2 700 MW can be securely and reliably managed—local generation GB of 2 000 MW plus interconnector transfer of up to 700 MW. The continuous rating of the interconnector flow from Region A to Region B is 1 000 MW (a thermal limit) but, in the absence of a suitable control scheme, it must be operated at a level such that the largest credible contingency (in this case, loss of 300 MW of Region B generation) does not push the transfer beyond its continuous rating. That is:

  secure limit (700 MW) = continuous rating (1 000 MW)
  – largest credible contingency (300 MW)

- If 100 MW load L_{B2} (e.g. a smelter) is associated with a control scheme that would trip it within 5 minutes of the post-contingent line flow reaching its 5-minute limit, and this scheme is procured by NEMMCO as a network loading control ancillary service (NLCAS), arming[402] the scheme enables the interconnector to securely operate at 800 MW, and thus (securely) service Region B load of up to 2 800 MW.

Figure E.12 Deploying load-tripping scheme to access 5-minute thermal ratings



If Region B load approaches 2 800 MW and the network loading control ancillary service at L_{B2} is armed, the higher "special" secure limit on interconnector flows of 800 MW could apply. This is because the occurrence of the largest single credible contingency (loss of a 300 MW generation unit) would result in the interconnector flow increasing up to 1 100 MW (its 5-minute rating) until such time as the control scheme operated by tripping the 100 MW of load at L_{B2} (sometime within 5 minutes). Tripping the 100 MW of load at L_{B2} would reduce Region B load back to 2 700 MW and interconnector flow to 1 000 MW (its continuous rating).[403]

[402] "Arming" the NLCAS involves preparing the load to trip in the event that flows on critical network elements move beyond their continuous rating – the design of the scheme is such that the load should remain "on" unless the relevant contingency occurs.

[403] If a contingency occurs and network elements exceed their secure operating limits, but stay within short-term ratings, the power system is declared to be in a satisfactory operating state and NEMMCO would have 30 minutes in which to return the power system to a secure operating state.

Note that generator control schemes—rapid unit loading or unloading—can be used to achieve similar outcomes to load-tripping schemes.

E.4.2.7 NEMMCO applications of support & control services

NEMMCO procures a network loading control service in the form of a smelter tripping scheme to access additional interconnector capability. It also procures reactive power capability in the form of Snowy generators operating in SynCon mode to manage voltage stability limits through the Snowy Region.

Under existing Rules, these services can be used either to:

- manage power system security or reliability [in accordance with clause 3.11.4(b)(1)]; or
- increase the benefits of trade from the spot market [in accordance with clause 3.11.4(b)(2)].

In order to increase the benefits of trade from the spot market, the cost of deploying the service should be less than the reduction in the total cost of generation dispatched in the market during the same period.

E.4.2.8 Summary

The current environment in which NSCS are delivered to the market is quite complex and contributes to a lack of clarity regarding the objectives for deploying NSCS. The environment can be described at a high level by matrixes that canvass several dimensions:

- **Responsibility:** "TNSPs" or "NEMMCO";
- **Purpose:** "security & reliability" or "benefits of trade";
- **Location:** "intra-regional" or "inter-regional";
- **Application:** "voltage control" or "network loading control"; and
- **Technology:** capacitor banks, SVCs, reactive power from generators in SynCon mode, reactive power from generators in generation mode, pre-contingent DSM, post-contingent DSM.

Table E.2 and Table E.3 outline the relations between these dimensions.

Table E.2: Service responsibility by purpose and location

	Intra-regional	Inter-regional
Security & reliability	Both TNSPs and NEMMCO have responsibility for procuring / supplying NSCS.	No clear responsibilities formally assigned. Both TNSPs and NEMMCO procure / deliver services that have effect in this space.
Benefits of trade	Both TNSPs and NEMMCO have responsibility for procuring / supplying NSCS.	No services specifically procured for this purpose. Where practicable, NEMMCO deploys services procured for other reasons that have effect in this space.

Table E.3: Service technology by responsibility and application

	Reactive power capability	Network loading control
NEMMCO	Procured from generators in either SynCon or generation mode to: • manage power system stability in credible circumstances; and • increase secure transfer capability of selected network elements.	Procured in the form of load tripping schemes to increase the secure power transfer capability of selected network elements.
TNSPs	• Provided in the form of SVCs, capacitor banks and reactors to manage intra-regional reliability. • Secured from generators in generation mode as part of connection agreement.	Procured from generators and loads as network support to manage intra-regional reliability.

E.5 Positive Flow Clamping option

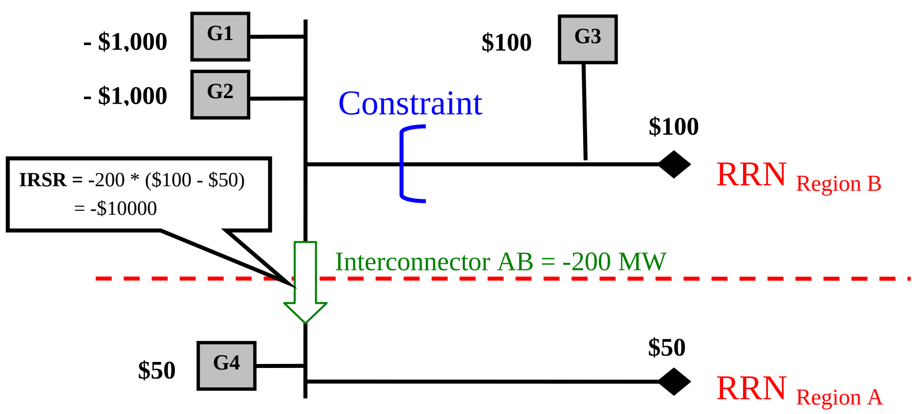
This section provides additional details on the concept of Positive Flow Clamping (PFC). In the Draft Report, we discussed PFC as an alternative to zero flow clamping (the current regime) as a way of managing negative residues under certain circumstances. While we are no longer pursing PFC as a viable alternative, it is informative to include a description of how it would work to provide context for the discussion in Appendix D where we present the reasoning for not accepting this option.

E.5.1 Description of PFC

Currently when NEMMCO forecasts that negative settlement residues between two regions will accumulate to a level of $6 000, NEMMCO reduces flow on the interconnector towards 0 MW until negative residue is no longer accumulating. In simple terms, the interconnector is clamped to 0 MW: zero flow clamping.

PFC represents an alternative response to the same set of conditions. Under PFC, NEMMCO still clamps the flow on the interconnector, but not to 0 MW; instead NEMMCO clamps it to some level of flow in the positively-priced direction (i.e. from low-priced region to high-priced region). As with the current regime, the PFC option would manage the accumulation of negative settlement residues. It could also make a greater contribution to the firmness of IRSR units by forcing the interconnector to flow in the positively-priced direction and thus to generate positive IRSR. In contrast, when zero flow clamping is invoked, no IRSR is generated to distribute to IRSR unit holders. This is illustrated in the example below (Figure E.13).

Figure E.13



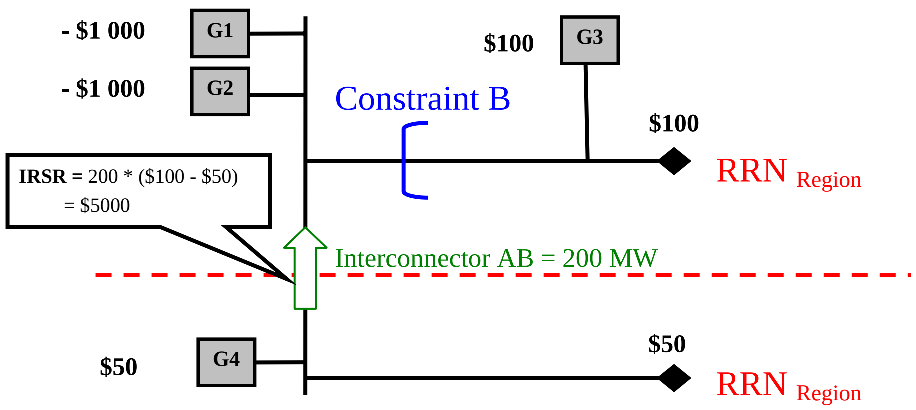
Constraint B prevents remote intra-regional generators G1 and G2 from setting the price in Region B. The price in Region B is set by local intra-regional generator G3. Generators G1 and G2 are thus able to bid below cost without affecting their settlement price. If they wish to generate at the RRP of $100, they might well enter very low bids to increase their chances of dispatch. At the extreme, they might bid -

$1 000. This could induce counter-priced flow on the interconnector. In the absence of intervention, negative residues would accumulate.

When the interconnector is clamped under the current regime to zero, neither positive nor negative residues accumulate. Although clamping to zero manages the issue of negative settlement residues, during the period of the clamping it renders the IRSR units useless as an inter-regional hedging instrument because zero IRSR is accumulating to distribute to IRSR unit holders. The financial impact of this situation is exacerbated if the regional price separation is high at the times when clamping is required.

PFC, will ensure that during intervention to manage negative residues, funds continue to flow to the IRSR fund by clamping the interconnector flow in the positively-priced direction. If we take the example discussed above, but this time clamp the interconnector to 200 MW in the positively-priced direction, there will be a positive accumulation of IRSR (see Figure E.14). Thus this option eliminates the negative residues, and generates positive residues to contribute to the firmness of the IRSR units. It does, however, mean that "cheaper" generation (based on the value of bids) is backed off to a greater extent.

Figure E.14



E.5.2 Implementation

PFC would be implemented by including additional discretionary constraint equations in dispatch. In practice, there is little difference between how the current clamping regime is implemented and how the PFC option would be implemented. Under the current clamping regime a constraint in the form of $I/C_{Flow} > 0$ is invoked when negative residues are identified. Under PFC a constraint in the form of $I/C_{Flow} > k$ would be invoked under similar circumstances, where k is some positive number (assuming that the positive flow direction is from the low-priced to high-priced region).

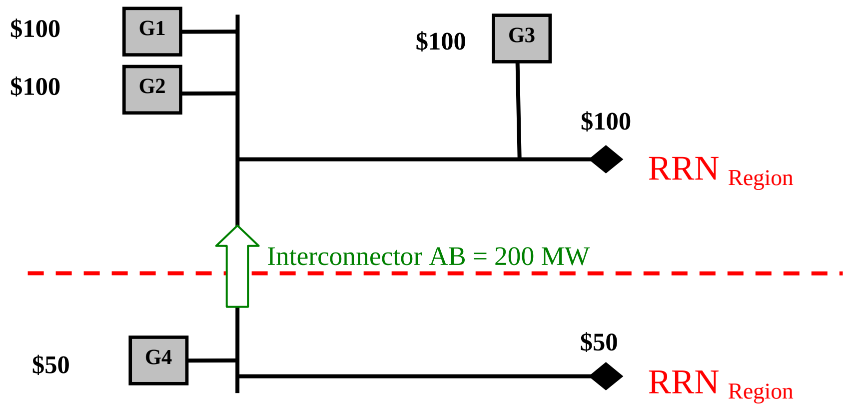
There are several approaches to establishing a value for k, as described below.

1. **Dynamic *k***

Using this approach, *k* would be based on the actual dispatched flow on the interconnector just prior to PFC being invoked.

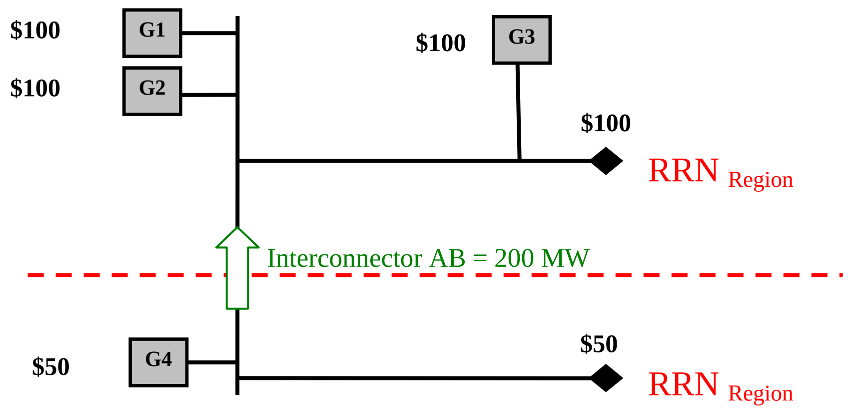
Consider the following example in which the interconnector is initially flowing in a positively-priced direction from Region A to Region B.

Figure E.15



Then, following the invocation on Constraint B, generators G1 and G2 are dislocated from the RRN and are thus incentivised to bid below cost to maximise dispatch.

Figure E.16

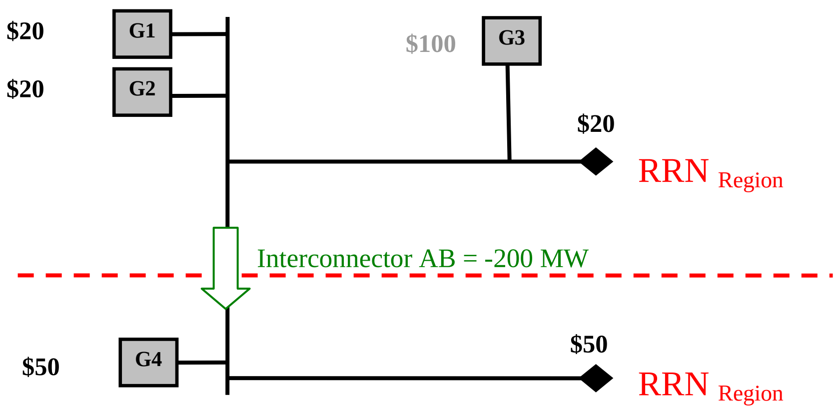


In the absence of intervention, G1 and G2 would force the interconnector to turn counter-price. As this is signalled through pre-dispatch, PFC would be invoked, clamping the interconnector at the pre-PFC flow of 200 MW.

This approach to establishing a value for *k* would, however, not be workable if counter-priced flow is established by a change in relative regional prices rather than a change in interconnector flow.

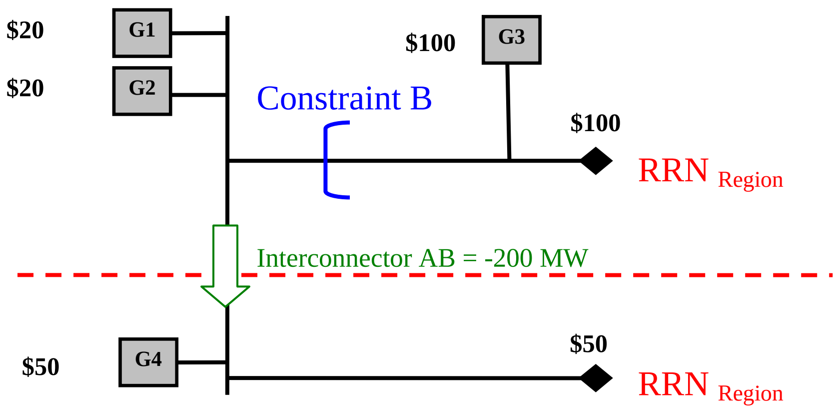
Consider the following example in which the interconnector is flowing in the positively-priced direction from Region B to Region A. G3 is not dispatched, and the price in Region B is set by G1 and G2.

Figure E.17



Following the invocation of Constraint B, G1 and G2 are backed off slightly and G3 is dispatched to meet load in Region B. G3 now sets the price in Region B at $100, and creates counter-priced flow.

Figure E.18



In this example, there is no pre-PFC interconnector flow in the positively-priced direction from which a value for *k* could be established. And in any case, it would be undesirable to clamp the interconnector in the positively-priced direction in this scenario. This would involve reversing the flow on the interconnector, which could require ramping up a large volume of generation in Region A and backing off a large volume of generation in Region B. This would be a major shift away from economic dispatch just prior to the invocation of Constraint B.

In this scenario, where the counter-priced flow was established by a change in relative regional prices rather than by a change in interconnector flow due to disorderly bidding, the interconnector could be (gradually) clamped to 0 MW to limit the effect on dispatch.

2. Static *k*

Using this approach, the value for *k* would be fixed at some level below the nominal capacity of the interconnector. The benefit of this approach is that it gives greater certainty as to the contribution to the IRSR fund at times when PFC is invoked. The difficulty of establishing a value for *k* remains, however. If *k* is set too low, PFC will make little contribution to firming IRSR units. If *k* is set too high, there is a risk that *k* could on occasions exceed the secure limit of the interconnector. Also compared to the approach of basing *k* on the pre-PFC dispatched interconnector flow, establishing a static value for *k* increases the risk of: (1) the price in the exporting region increasing to a level at which PFC itself creates counter-priced flow but in the opposite direction; and (2) requiring generators in the exporting region to be constrained-on to support the interconnector flow. These risks would be greatest on those occasions where *k* is significantly higher than the pre-PFC interconnector flow. For the reasons just outlined, this approach to setting *k* would need to be accompanied by a mechanism enabling the value of *k* to be reduced when necessary (which reduces the benefit of certainty with this approach).

3. Maximum capacity *k*

Using this approach, *k* would be set dynamically based on the maximum available capacity of the interconnector at the start of each dispatch interval. The benefit of this approach is that the value of the IRSR fund is maximised. The disadvantages are that constraining the interconnector to this level may represent a major shift from pre-PFC dispatch, which could raise issues regarding dispatch efficiency. As is the case with setting a static value for *k*, this approach also has a higher risk of creating counter-priced flow in the opposite direction and constraining-on generation.

Summary

The core differences between the three approaches are as follows:

- approach 1 aims to maintain dispatch as close as possible to the pre-PFC dispatch;
- approach 2 aims to maximise certainty by pre-defining the expected interconnector flow when PFC is invoked; and
- approach 3 aims to maximise the value of the IRSR by constraining-on the interconnector at its maximum physical capacity.

We considered approach 1 would distorts dispatch the least and was least likely to cause side effects (i.e. such as exceeding secure interconnector limits, inducing counter-priced flow, and constraining-on generation).

E.5.3 Trigger for invoking PFC

PFC could be triggered in various ways, including: (1) when negative residue is forecast, as is currently the case; or (2) when interconnector flow is first backed off by generators reducing their bids in response to dislocation from the RRN, regardless of the likelihood of negative residue. By invoking the measure when the interconnector is first backed off, the value of the IRSR would be maximised. However, this would represent a shift *from* intervention to manage negative residues and *to* intervention to influence dispatch results. It may also be difficult to identify reasons for change in interconnector dispatch. For these reasons PFC should be invoked based on a negative residue threshold.

The next question is what the negative residue threshold should be. Our recommendation in respect of zero flow clamping thresholds is that the negative residue threshold should be increased from \$6 000 to \$100 000.[404] This is based on the view that clamping creates uncertainty for Market Participants, which increases risk premiums and thus should be avoided or at least minimised. Since the sole purpose of zero flow clamping is to manage negative settlement residues, whereas PFC would also increase the firmness of IRSR units, it would seem contradictory to lengthen the period before PFC is invoked; this would have the effect of reducing the firmness of IRSR units. The threshold for PFC should remain at a level of \$6 000.

E.5.3.1 Design overview

Based on the discussion above, we developed the following high-level design of PFC:

- PFC would be considered only for counter-priced flow events that are caused by generators' incentives to bid below cost due to their dislocation from the RRN. Such events would be pre-defined and identified by constraint equations.

- PFC would be invoked when negative residue caused by one of the defined constraints is forecast to accumulate to \$6 000.

- Under PFC, the interconnector would be clamped to the flow at which that interconnector was dispatched in the dispatch interval just prior to the PFC invocation.

- If the interconnector turns counter-priced or was already flowing counter-priced prior to PFC being invoked, then the default arrangements for managing counter-priced flow (i.e. clamping to zero MW) would apply.

[404] See Chapter 3 of the Final Report or Appendix C, section C.2 for more information on this recommendation.

For the reasons discussed further in Appendix D, we are not proposing further development on PFC as an alternative to managing negative settlement residues, however.

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