AEMC Congestion Management Issues Paper

Submission from the Latin Group of Generators

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Structure of this Submission

1. Our guiding principles
2. CSP/CSC beats Region Change
3. Full CSP/CSC beats Gradual CSP/CSC
4. CSC allocation beats CSC auction
5. CSC allocation
6. The complete model
7. Relationship with other areas of NEM reform
8. Conclusions

In this submission, we evaluate the main alternative designs for a congestion management mechanism against a set of six guiding principles. These principles derive from the four "themes" which the AEMC has set out in its issues paper (section 1.1.2) and are described in the first section of the submission.

Sections 2-4 then evaluate the main design alternatives. We conclude that, based on the principles:

- CSP/CSC is preferred to region change
- a "full" approach to CSP/CSC is preferred to a "gradual" approach
- allocating CSC to existing generators is preferred to auctioning them

Section 5 sets out some principles to be applied in designing the CSC allocation process and how these may be applied.

Section 6 provides a comprehensive description of the preferred approach that is built up in sections 2-5. It considers the physical and commercial impact that this model would have in some familiar constraint scenarios and illustrates how the benefits of more efficient dispatch are distributed.

Section 7 considers this congestion management mechanism in the broader context of the NEM and current NEM developments.

Section 8 presents our conclusions and our recommendations to the AEMC.

Section 1: Our Guiding Principles

AEMC objectives vs our principles

The AEMC Issues Paper establishes four "themes" for the Congestion Management Review

AEMC Themes

- *Improve Certainty and Practicality*: participants can understand & predict impact of CM regime on the NEM
- *Facilitate Risk Management*: participants can manage congestion risk and trade risk to parties who can best manage it
- *Ensure NEM Efficiency*: promote static (dispatch) and dynamic (investment) efficiency
- *Protect System Security and Reliability*: any CM regime must not jeopardise or degrade system security

Our Principles

- *Constraint Pricing*: generators should face the price of all material constraints: whether inter- or intra-regional
- *Promote Forward Market*: new CM regime should not adversely impact liquidity or effectiveness
- *Low Regulatory Risk*: minimise commercial uncertainty associated with future regulatory decisions (eg by AEMC)
- *Transparency*: where complexity exists, participants should be able to model, predict and so manage this complexity
- *Low Impact*: to the extent possible, any substantial adverse impact on the market value of existing assets (eg power stations) should be avoided
- *Low Cost*: the cost and complexity of implementing and operating the CM regime should be minimised

We have been guided by these in establishing "principles" for evaluating alternatives

Section 1.1.2 of the AEMC Issues Paper presents four "themes" which the AEMC intends to use to "provide a framework to consider the current regime and assist in assessing any proposed improvements". We support these four themes.

However, whilst these "themes" (really high-level goals) are commendable, they are fairly abstract and do not necessarily lend themselves to evaluation and assessment. For example, "NEM efficiency" is, of course, paramount, and yet the difficulties of identifying and assessing changes in efficiency – whether quantitatively or qualitatively – are well known.

In contrast, a principle such as "generators should face the price of all material constraints" is more concrete and measurable. Indeed, all of our guiding principles are such that it is relatively straightforward to answer the question: "which of these design alternatives better accords with this principle?"

We have six principles and anticipate that five of these are uncontentious. The sixth – the principle of "low impact" – may need some explanation and justification. It says that existing assets (eg power stations) should not see their market value diminish as a result of any new arrangements. Economists often dismiss such "distributional" considerations as irrelevant to market efficiency. In a static sense, they are correct. However, a market in which shareholder value can be decimated on a regulator's whim (recognising that the NEL does not explicitly require the AEMC to consider distributional effects) is obviously not an attractive environment for investment, to the detriment of "dynamic" efficiency. In short: "low impact" is a prerequisite for dynamic efficiency.

Relating our principles to AEMC themes

We support the AEMC's emphasis on efficiency, certainty and risk management…

	Improve Certainty and Practicality	Facilitate Risk Management	Ensure NEM Efficiency	Protect System Security
Constraint Pricing			Gens incentivised to provide cost-reflective bids	NEMMCO better able to manage congestion
Promote Forward Market		Participants can hedge congestion risks	Improves operational planning	
Low Regulatory Risk	Reduced regulatory uncertainty		Improved environment for new investors	
Transparency	Participants able to predict impact of congestion	Congestion can be priced and traded forward		Informed market can contribute to congestion relief
Low Impact	Reduce impact of future regulatory decisions		Creates helpful precedent for new investors	
Low Cost	Easy to understand and implement		Minimise transaction costs	

…and stress the importance of reducing regulatory risk and promoting forward markets

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The above table shows how our six principles correspond to the AEMC's themes.

Constraint Pricing is necessary to ensure static efficiency and system security (through price-based rationing of scarce transmission capacity) and dynamic efficiency (through locational signals to new generation investors). The principle only applies to the generation side, as the efficiency and security benefits of pricing the demand side are limited.

Forward Markets are the mechanisms through which participants manage and allocate (spot) risk. They can also send forward pricing signals to new investors.

Regulatory Risk is the main source of uncertainty in the NEM, because regulators' behaviour can be neither modelled nor hedged. It is also a major deterrent to investment and so an impediment to dynamic efficiency.

Transparency allows participants to model, analyse and price congestion risks and thus (potentially) re-allocate these risks through forward trading.

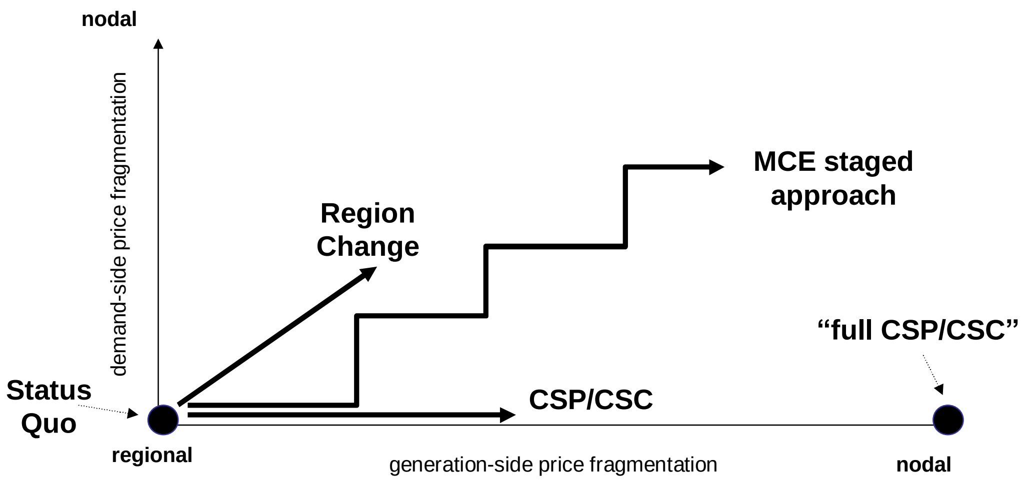
Low impact as a guiding principle provides comfort to current and future investors that, despite a raft of current and future NEM developments, commercial uncertainty will be mitigated. As noted previously, it therefore is a prerequisite to dynamic efficiency.

Finally, *low cost* of implementation and operation not only ensures that transaction costs are minimised but also creates an emphasis on simplicity of design.

Section 2: CSP/CSC beats Region Change

Market Design Space

The available options are for more pricing for generation, for demand or for both…



…and how we decide to evolve from "here" to "there"

In the NEM, "constraint pricing" is equivalent to "price fragmentation", in the sense that NEM spot prices will diverge either "side" of a price constraint. So the scope of solutions to congestion management is essentially driven by the answers to two questions:

- how much price fragmentation should we have on the demand-side?
- how much price fragmentation should we have on the generation-side?

The diagram above represents these answers as two dimensions in a "market design space". At bottom left we have the status quo: the current regional model, with limited fragmentation on both sides of the market.

"Region change" means equal fragmentation on both sides of the market and so is represented by a diagonal movement towards the upper right of the diagram.

"CSP/CSC" on the other hand, fragments only generation prices and so is represented by movement along the horizontal axis.

The MCE has proposed a combination of CSP/CSC and Region change, which is represented as climbing stairs towards the upper right, with the treads being the CSP/CSC component and the risers being region change.

We consider a fifth alternative: a "full" CSP/CSC model (for want of a better term), where all actual and potential constraints are priced to generation from "day one". Although we represent this as being at the bottom right (ie full generations-side fragmentation), in practice generation prices will only fragment to the extent that congestion occurs.

Section 2: CSP/CSC beats Region Change

Evaluate CSP/CSC against new regions

When introducing new generation prices the benefits are high and the costs low…

	CSP/CSC		Region Change	
Constraint Pricing	✓	All material constraints priced but to generation only	✓	All material constraints priced to generation and demand
Promote Forward Market	✓	Demand-side and RRN markets unaffected. CSCs leave gens exposed primarily to RRN price	✗	Fragmentation of markets between more hubs. No allocated contracts
Low Regulatory Risk	✗	Risk to generators associated with timing and definition of new CSPs/CSCs	✗	Risk to generators and retailers associated with timing and definition of new regions
Transparency	✓	All material constraints individually identified and priced	?	Treatment and impact of hybrid and trans-regional constraints may remain unclear
Low Impact	✓	CSCs can be allocated to minimise impact on existing generators	✗	Problematic to protect existing customers. Impact on uniform retail pricing policies
Low Cost	✓	No change to dispatch. Changes to settlement only. Only affects generators	✗	Changes dispatch and constraint formulation. Major impact on retailers

…but when it comes to introducing new demand-side prices, the opposite is true

This table evaluates CSP/CSC against Region Change using our guiding principles. The "✓", "?" or "✗" symbol summarise our view of how each option "scores" against each principle.

The scorecard of region change is poor. This should come as no surprise. Despite being a feature of the NEM rules since inception, region change has been strongly resisted by a range of stakeholders. The latest proposal (put forward by the MCE) is that if region change is to happen at all it should face a high hurdle, happen infrequently and be subject to a long notice period: in short, better late or never.

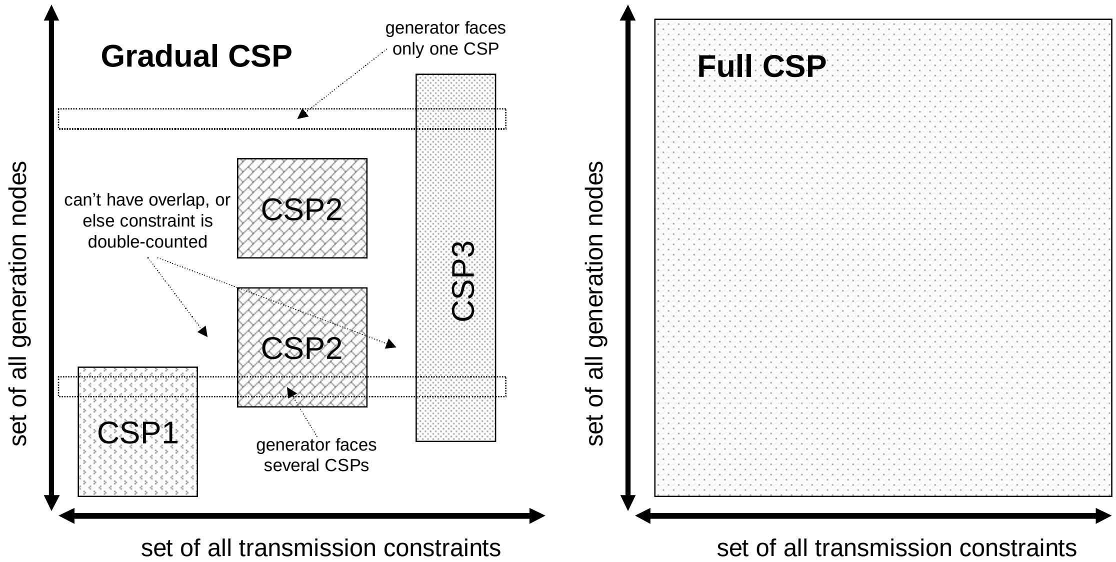
The problem is that region change is highly disruptive to NEM operation. It disrupts the forward markets, which are predicated on pricing at a stable and limited set of regional reference nodes (RRN) or, in the case of the settlement residue auction (SRA), stable interconnector definitions. It disrupts dispatch, as it would require substantial reformulation and re-orientation of the constraint library. It disrupts retailers who would need to redevelop all of their pricing, marketing and billing systems. Last, but not least, it disrupts government policy, particularly on retail pricing, where this is predicated on a single NEM wholesale price across a State.

In contrast, CSP/CSC causes limited disruption. The "Snowy Trial" has demonstrated this. It has been implemented through some straightforward "add-ons" to NEM settlements, with no impact on dispatch systems. It has only indirectly affected regional forward markets, primarily through its direct affect on the Snowy-NSW interconnectors. Its main weakness is the uncertainty regarding the introduction of new CSP/CSCs: a weakness it shares with Region Change.

Section 3: Full CSP/CSC beats Gradual CSP/CSC

Gradual and Full CSP Approaches

CRA and MCE have proposed introducing new CSPs one at a time.



But defining multiple CSPs is complex. Why not have a single, comprehensive approach?

Behind the apparent simplicity of the CRA description of the CSP/CSC approach lays substantial complexity. The Snowy Trial revealed this complexity. Though a simple description might regard Tumut-Murray congestion as managed by a single constraint, in fact it is made up of dozens of separate constraints in the NEMMCO constraint library. NEMMCO is required to regularly determine the set of constraints which together constitute the Tumut-Murray "CSP".

The Snowy Trial was designed to only apply the CSP to Snowy Hydro at the Tumut nodes. However, it could have (and, more logically, should have) been applied elsewhere, particularly to the Snowy-Vic interconnector.

Thus, when any new "CSP" is introduced, it must be decided which constraints and also which nodes and interconnectors are to be encompassed. The left hand diagram above shows this diagrammatically, where 3 separate CSPs have been introduced. NEMMCO must ensure that the CSPs do not overlap (where a constraint is included in two or more CSPs) to avoid double counting of congestion. Each generator must know which of the CSPs apply to their nodes and which constraints are involved in each CSP.

This diagram does not show an additional area of complexity: that for each separate CSP, CSCs must be defined and allocated. A generator node may be the subject of several CSPs, each with a different associated CSC.

The above right diagram illustrates how this complexity does not arise in the "full CSP" approach. All constraints and all generation nodes are included: end of story.

Section 3: Full CSP/CSC beats Gradual CSP/CSC

Features of full and gradual CSP/CSC options

The gradualist approach to region change has not worked, so why repeat the mistake?

Gradual CSP/CSC

- as set out in the CRA paper to the MCE
- new CSPs introduced only *after* "material congestion" emerges: possibly with a significant delay
- similar cost-benefit criteria to new region introduction
- AEMC would conduct reviews and decide to introduce new CSP
- new CSP would be defined by which constraints are to be included (cf Snowy Trial) and to which generator nodes they are applied
- CSCs would be allocated to affected generators and interconnectors
- New generators who create new congestion may get allocated CSCs
- No changes to dispatch: CSP/CSC applied through change to generator settlements

Full CSP/CSC

- all potential intra-regional constraints are included, whether or not currently binding or material
- this means that CSPs always apply the instant congestion occurs: potentially, CSP forward markets could even predict future congestion
- CSPs are applied to all generator nodes
- No requirement for further monitoring and reviews to introduce additional CSPs
- CSCs are allocated to all currently existing generators
- No CSCs allocated to new entrant generators, who therefore (efficiently) face whatever constraint prices apply to them
- No changes to dispatch: CSP/CSC applied through change to generator settlements
- Of course, only the constraints that bind will affect price outcomes

It just creates unnecessary uncertainty for existing and future participants

The process for region change has always been difficult and contentious. As the Issues Paper recounts (section 2.5.1) there have been at least 4 reviews of this process since NEM commencement and it is still not resolved. And, of course, no change in regions has yet occurred.

This is not surprising. Region change is highly disruptive. Regulators must be certain that the benefits outweigh the costs before approving a change. Any change creates winners and losers, and the losers are bound to use every opportunity to resist it.

What is more surprising is that the MCE should contemplate repeating history by setting out a similar process for CSP/CSC introduction. We have no doubt that any such process will be complex, contentious and costly and see a likelihood that it will fail to ensure timely introduction of constraint pricing to manage congestion, just as region change has failed.

However, whilst the NEM design was justified at the time – it would have been extremely difficult to have created sufficient number of regions at NEM commencement to avoid the need for additional future regions – no such justification exists in relation to "gradual" CSP/CSC. We believe that design and implementation of full CSP/CSC is practical, straightforward and low-cost. Since NEMMCO is able (as it has demonstrated in the Snowy Trial) to price and settle a subset of the CSP/CSC "space", we see no reason why it cannot similarly implement the full CSP/CSC.

Section 3: Full CSP/CSC beats Gradual CSP/CSC

Evaluate gradual CSP/CSC against full CSP/CSC

A "full" approach is simpler, more transparent and lower cost…

		Gradual CSP/CSC		Full CSP/CSC
Constraint Pricing	✗	Risk that newly material constraints not priced in time (cf Regions). New gens may get CSC protection	✓	All congestion priced immediately to generation. New gens will not receive CSC protection
Promote Forward Market	✓	Demand-side and RRN markets unaffected. CSCs leave gens exposed primarily to RRN price	✓	Demand-side and RRN markets unaffected. CSCs leave gens exposed primarily to RRN price
Low Regulatory Risk	✗	Risk to generators and retailers associated with timing and definition of new CSPs and allocation of CSCs	✓	All possible CSPs have been introduced. All CSCs have been allocated
Transparency	✗	Low transparency for constraints not currently subject to CSPs	✓	Fully transparent
Low Impact	✗	Existing gens impacted if CSC allocated after new entrant creates congestion	✓	CSCs can be allocated to minimise impact on existing generators
Low Cost	✗	AEMC costs of monitoring the need for new CSP/CSCs. NEMMCO costs of identifying CSPs' scope	?	One-off change to NEMMCO and generator systems. However, all costs incurred immediately (no discounting)

*…because NEMMCO **already** defines and prices a "full" set of constraints*

Substantial price fragmentation has always been resisted, on the grounds that, unless congestion is "material" and "enduring", there is little benefit from pricing it but significant cost.

We agree on the "benefits" side in principle, but would point out that, in practice, timely identification and pricing of "material" congestion is problematic and likely to lead to delays. On the other hand, we think the cost concerns are misplaced.

Costs may arise within NEMMCO or within generator companies (retailers are largely unaffected by CSP/CSC). NEMMCO costs will not be substantial, because (under option4 formulation) *all of the constraints and prices already exist in the NEM dispatch engine* (NEMDE). It is simply a matter of processing and reporting them.

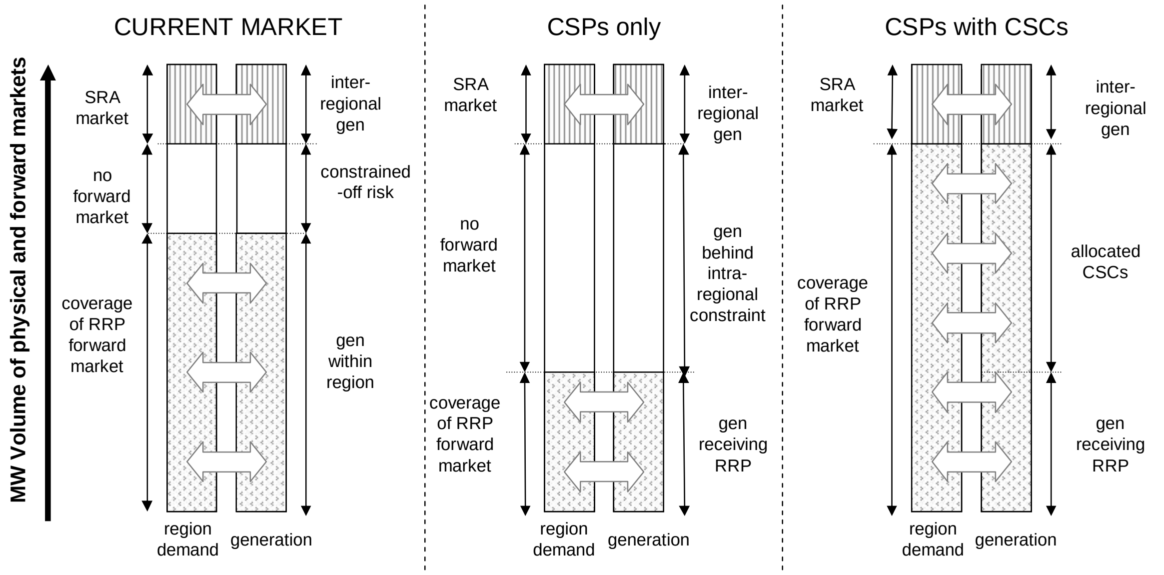
Although generators will bear some costs of modelling and analysing intra-regional congestion, it is sometimes forgotten that *they already do*. For some generators, the volume risk associated with intra-regional congestion is a major and continuing source of concern. This concern is exacerbated by a lack of clarity and transparency in how such constraints are managed in current dispatch and the inability to price, control or hedge these risks.

As generators, we accept the potential for increased complexity of pricing, bidding and hedging brought about by full CSP/CSC, since it also brings much greater transparency and reduced regulatory risk. We have the resources and expertise to manage transparent, market-driven complexity. Managing the regulator is another matter.

Section 4: CSC allocation beats CSC auction

Role of CSCs in Protecting Forward Market

A forward market relies on concentrated trading at a few key "hubs"…



…CSCs will prevent the existing regional forward markets from being fragmented

We think CRA's coupling of pricing (CSP) with hedging (CSC) was an important breakthrough in the development of congestion management design. Market designers are apt to consider the spot market in isolation, but in reality a spot market cannot be effective without a complementary forward – or "hedging" – market. California is an extreme example of what happens when you have one without the other; NZ a less extreme one.

Currently (above left), regional demand is supplied either from generation in the same region and the remainder inter-regionally. Since most generation and demand trades in the NEM at a common price (the regional reference price or RRP), forward trading – using RRP derivatives – is mutually beneficial and straightforward. Generators may "withhold" some hedges, due to the risk of being constrained-off. The inter-regional segment can be hedged through the SRA market.

Imagine the introduction of CSPs without CSCs (above middle). Potentially a large portion of the within-region generation may face the CSPs and so no longer trade at the RRP. The scope of the regional forward markets shrinks and there is no new "CSC" market to replace it. In short, generators facing the CSP "basis risk" may withdraw from the forward markets, leaving retailers unhedged.

CSCs will restore this "lost market" (above right) since, where its output is covered by CSCs, a generator will continue to trade at the RRP and, as before, will seek to hedge this exposure through the regional forward market. NZ made the mistake of introducing nodal pricing without considering the need for accompanying "nodal hedges". Australia must not make the same mistake.

Section 4: CSC allocation beats CSC auction

Demolishing some Myths about CSC Allocation

Terminology such as "rights" and "contracts" creates unnecessary concerns…

Myth	Response
• CSCs are "transmission rights" which are inconsistent with open access to transmission	• CSCs are just financial adjustments to NEM settlements. Their effect is comparable to SRAs, which already exist in the NEM
• CSCs are "contracts" which are not allowed on a common carriage network	• CRA coined the "contract" terminology, but CSCs are nothing like the access contracts seen on contract carriage networks
• allocated CSCs would need to be authorised	• the allocations would be defined in the NEM Rules (perhaps through derogations) and so would not require authorisation
• allocated CSCs are a barrier to entry to new gens	• no, improved transparency and reduced regulatory risk actually remove barriers
• CSC allocation gives generators something for nothing	• Generators will get broadly similar access to that enjoyed in the current regional model, certainly nothing more
• since load pays TUoS, it should receive the CSCs	• the allocated CSCs will allow retailers to contract with generators at the RRN, so they also benefit from them
• if generators receive CSCs they should pay TUoS	• since generators will now see a locational CSP-adjusted price at the margin, charging TUoS as well would be double counting

…allocated CSCs would simply provide the same "rights" that generators enjoy at present

The concept of constraint support "contracts" (aka transmission "rights") has created much anxiety amongst regulators. We believe such concerns are unnecessary and misconceived.

Much of the blame must be placed on the language that is used: CSCs are neither "contracts" nor "rights" in the normal sense of the words. (Note: we use the CSC terminology simply to avoid further confusion from introducing new terminology; we would prefer to use a term such as "pricing basepoints").

As we note below, CSCs can either be allocated or auctioned. In the former approach, we see the allocated quantities being parameters specified pursuant NEM rules, just like other NEM parameters such as VoLL, loss factors and region definitions. They would form part of the settlement algebra. They are not a "contract" with anybody, they give the "holder" no rights of dispatch or transmission access. They would be determined pursuant to the normal NEM rule change process. They are no more a "free handout" to generators than the existing regional definitions are a "free handout" to retailers. In fact, as we discuss below, the allocated CSCs would broadly encapsulate the "rights" that generators already enjoy under the current NEM arrangements.

If the CSCs were to be auctioned, the process would be analogous to (although far more complicated than) the existing SRA. The purchaser of a CSC would hold a right to a defined portion of the settlement residue. Again, access issues simply do not arise.

Section 4: CSC allocation beats CSC auction

Evaluate allocated or auctioned CSCs

*Whilst CSCs **could** be auctioned rather than allocated…*

	Allocated CSCs	Auctioned CSCs
Constraint Pricing	✓ Fixed allocation of CSCs will not limit effectiveness of CSPs	? Gens could gain market power by acquiring or rejecting CSCs, potentially distorting constraint prices
Promote Forward Market	✓ CSCs can be fully allocated, leaving size of RRP market unaffected	✗ Auction may not fully sell CSCs: eg because "constrained-on" CSCs not sold, or due to reserve price (cf SRA)
Low Regulatory Risk	? CSC Allocation could be changed in future by AEMC, but unlikely.	✓ Should be no need for regulator to be involved in auction process.
Transparency	✓ Allocation of CSCs would be made public	✗ Auction results may remain private due to confidentiality issues
Low Impact	✓ CSCs can be allocated to minimise impact on existing generators	✗ Existing gens impacted by payment of auction fees or inability to obtain required CSCs
Low Cost	✓ Allocations can be calculated "off-line" based on agreed rules	✗ Need to establish complex clearing mechanisms, possibly coordinated with the SRA process

…this would create substantial additional costs and complexity but no efficiency benefit

We recognise that, in principle, CSCs could be introduced into the market through an allocation or auction mechanism. Some common issues arise. Most importantly, the issued CSCs must be "underwritten" by the "intra-regional settlement residue": the additional settlement residue that arises as a result of the pricing of intra-regional constraints. This is analogous to the inter-regional settlement residue underwriting the existing SRA instruments.

However, this analogy shouldn't be taken too much further. Because the inter-RSR arises primarily from a single constraint (although this is complicated in the case of hybrid constraints) it can be marketed as a single hedging instrument. In contrast, the intra-RSR may arise from multiple concurrent constraints and therefore be of little use to any individual generator who would face only a subset of these constraints. To address this problem – and divide the intra-IRSR up into separate "hedges" is complex and may take significant time and cost to implement. As we show below, CSC allocation is straightforward and can be implemented without delay.

However, our main concern with an auction process is that it would breach our "low impact" principle. Whilst a generator adversely affected by the introduction of CSPs could purchase hedging CSCs in an auction it would, of course, have to pay market value for these. Since the market value is equivalent to the value of the CSCs, this purchase does nothing to offset the value impact, it simply allows it to be hedged to ensure that it doesn't get any worse.

Therefore, we see CSC allocation as a critical feature. Notwithstanding this, an auction could be introduced in the future, to "market" any spare or new transmission capacity or to facilitate secondary "trading" of CSC allocations.

Section 5: CSC allocation principles

CSC Allocation Principles

We have developed some guiding principles for CSC allocation…

Principles		Rationale
allocation to all existing generation capacity	➡	the primary objective is to minimise the value impact of CSP/CSC on existing assets
no allocation to new generation	➡	for dynamic efficiency, the full constraint price should be signalled to new investors
allocation to some interconnectors	➡	for “hybrid” or “trans-regional” constraints, CSCs required to firm up IRSR and prevent deficits
nominal MW based on historical dispatch	➡	this will prevent CSPs adversely impacting current generation value
dispatch based on peak demand and “system normal” transmission	➡	for simplicity a single scenario (and therefore a single MW allocation) is proposed
actual MW scaled back during transmission outages	➡	settlement shortfalls, during periods of reduced transmission, must be avoided
CSCs will expire when a power station is decommissioned	➡	the objective is to hedge the (net present) market value of power station operation

…upon which the detailed allocation rules can be developed

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Some principles for the CSC allocation process are listed above, which will guide the future development of detailed rules and procedures.

Firstly, CSCs should be allocated, in accordance with our “low impact” principle, only to existing generation capacity. There should be no guarantee of any allocation for future generation capacity, since this could dilute the locational signal provided by constraint pricing and so degrade dynamic efficiency. The details of how CSCs might be issued in the future are important but do not need to be resolved here.

CSCs may also be “allocated” to interconnectors, where a “hybrid” constraint means that interconnector flows are constrained by intra-regional constraints. As seen in the Snowy Trial, this allocation means that any payments due to such CSCs would be paid into the interconnector fund which is then distributed to holders of SRA instruments. This allows the SRA to provide a full RRN-to-RRN hedge, rather than just a hedge against the “cross-border” inter-regional constraint.

Since CSCs are intended to mitigate the impact of moving from *current* dispatch arrangements, allocation will be based on generation dispatch under these arrangements. For simplicity, it is proposed that a single dispatch scenario is used – based on peak demand and system normal transmission – so that a single allocated quantity is determined for each generator.

CSC payments must be fully funded by intra-RSR. To avoid a shortfall during periods of transmission outages, the “nominal MW” determined in the allocation process will be scaled back to an “actual MW” on which payments are determined.

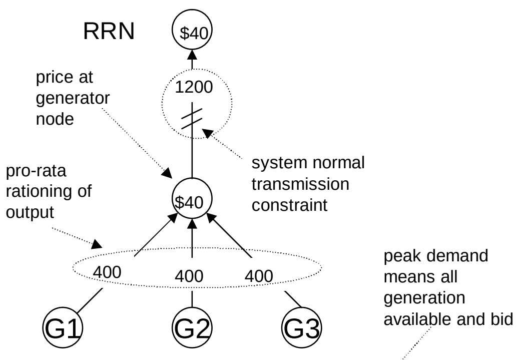
Allocated CSCs would last for the life of the relevant generating asset.

Section 5: CSC allocation principles

Allocation Example: Simple Constraint

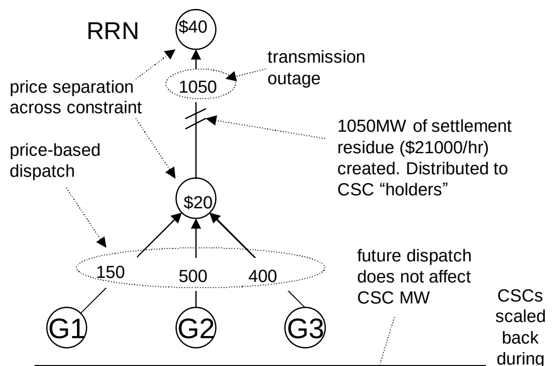
Nominal allocation is based on dispatch outcomes under the current arrangements…

Historical Dispatch: System Normal



	G1	G2	G3
capacity	500	500	500
dispatch	400	400	400
nominal CSC MW	400	400	400

Future Dispatch: Transmission Outage



	G1	G2	G3
dispatch	150	500	400
nominal CSC MWs	400	400	400
actual CSC MWs	350	350	350

…actual allocation depends upon the level of transmission capacity available

For a simple intra-regional constraint, CSCs will be allocated according to *current* dispatch of generating capacity behind that constraint (above left). The example illustrates how the current volume-based rationing leads to each generator being dispatched in proportion to capacity, and so the nominal CSC MW are allocated accordingly.

Once the CSP/CSC mechanism is operational, rationing will be price-based and so the dispatch amounts of the generators will vary depending upon their bids (above right). However, the nominal CSC amounts are fixed and do not depend upon bidding. Thus, at the margin, the generators will always face the CSP and will bid accordingly. The CSCs simply provide a hedge against the CSP, at the CSC quantity.

Where a transmission outage occurs, actual CSC MW must be scaled back to prevent the possibility of a settlement deficit. This is analogous to what occurs with SRA payouts during interconnector outages.

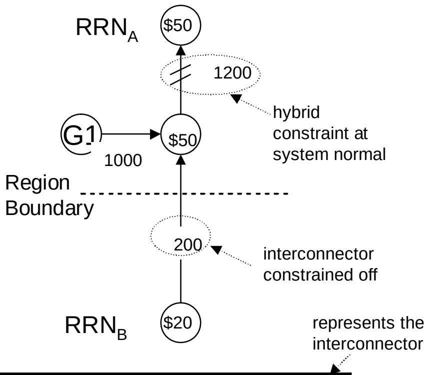
The scaling back here is simple, because there is only a single constraint. In practice, there may be several intra-regional constraints binding concurrently, some - but not all - of which are affected by transmission outages. In this situation, scaling of CSCs could vary, depending upon which constraints and generators are affected by the outages. However, this could be complex, and an alternative approach of a single, common scaling factor for all CSCs may be preferable. This is an area where further analysis is needed.

Section 5: CSC allocation principles

Allocation Example: Hybrid Constraint

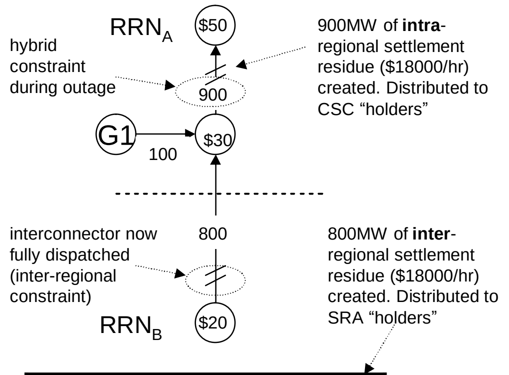
CSCs may be allocated to the interconnector…

Historical Dispatch: System Normal



	G1	B->A
capacity	1000	800
dispatch	1000	200
nominal CSC MW	1000	200

Future Dispatch: Transmission Outage



	G1	B->A
dispatch	100	800
nominal CSC MW	1000	200
actual CSC MW	750	150

CSC payout also distributed to SRA holders

…payments on this CSC are distributed to holders of the relevant SRA instrument

For a hybrid constraint, CSCs may also be allocated to an interconnector. Under current arrangements, a "remote generator" ("G1" in the diagram above left) will bid below the price in the neighbouring – irrespective of its actual operating costs – and so "constrain off" the interconnector. Notwithstanding the efficiency or otherwise of such dispatch, since the purpose of the CSC allocation is to achieve the "low impact" principle, the nominal CSC MW will be allocated between the remote generator and the interconnector according to this dispatch.

Once the CSP/CSC mechanism is operational, the remote generator will no longer bid below the "interconnector", because in doing so it will simply drive down the "local" reference price. So, if the inter-regional generation is cheaper than the local generator, the interconnector will flow to its capacity (above right). This does not affect the CSC allocation, however, which remains based on the "old" dispatch rules.

If a transmission outage causes a reduction of intra-regional transmission capacity, the CSC MW allocated to the remote generator and the interconnector will be scaled back accordingly. Thus, the SRA holders bear some "non-firmness" risk on the intra-regional capacity, as they do on the inter-regional capacity.

However, as the interconnector is still at "system normal", the full interconnector capacity flows into the inter-regional SR and is distributed to SRA holders. Thus, the "non-firmness" of the inter- and intra-regional transmission capacities are clearly quarantined, as are any transmission outages occurring within neighbouring regions.

Section 5: CSC allocation principles

Evaluation of Allocation Process

Our proposed allocation has been guided by our high level principles…

		Allocation Process
Constraint Pricing	✓	Allocation is independent of (current) dispatch and so does not affect constraint pricing at margin. Allocation to all generators (constrained-off and constrained-on) mitigates potential for market power to distort pricing
Promote Forward Market	✓	Generators obtain similar levels of "access" to RRP as now, so existing forward contracts and future trading should be largely unaffected. Commonality of terms and conditions would allow trading of CSC derivatives
Low Regulatory Risk	✓	Clear guiding principles will limit the scope for regulatory discretion. Since the CSC allocation will be included in the Rules, a full, and final, rule change process is required
Transparency	✓	The principles provide clarity on how CSCs are allocated. The scaling back process means that there is no "flow on" from CSCs to either the demand side or to other regions
Low Impact	✓	Since the allocation is based on historical dispatch, impact is minimised. If a generator continues to be dispatched at the same level it will receive the same level of payment: ie at the RRP
Low Cost	✓	The allocation process is straightforward. The "scaling back" during transmission outages is simple to apply operationally. It also means that minor errors in estimating transmission capacity (eg between winter and summer) are unimportant

…which, in turn, are derived from the concerns and "themes" articulated by the AEMC

We have designed the allocation principles to align with our 6 "guiding" principles described previously. However, it is worth checking to see what has been achieved.

Most importantly, because the CSC allocations are fixed and independent of actual dispatch on the day, the effective price seen by generators *at the margin* – irrespective of CSC allocation – incorporates any relevant intra-regional constraint pricing. Thus, capacity rationing is price-based and efficient.

Since generators will, under current arrangements, participate in the regional forward market based on their expected dispatch levels, their ability to do this under future arrangements is preserved. It does not matter whether they continue to be dispatched to the same levels. Thus, existing forward contracts are unaffected and future participation is protected. Incidentally, this means that there is no need for a long notice period before CSP/CSC is introduced (cf Region Change).

Although nominal CSC allocation is based on current, system normal, transmission capacity, this will be automatically adjusted as capacity changes in the future. Therefore, there will be no need to adjust the CSC allocation in the future.

The process is designed to ensure "low impact" and, as generators, we would be comfortable with a CSC allocation consistent with the principles we have described.

Finally, because only a single CSC is allocated to each generator – though this would hedge against multiple potential constraints – the allocation process is simple and low cost. This contrasts with allocation in the "gradual" approach, where the allocation may need to be repeated many times, providing multiple different allocations.

Section 6: the complete model

Description of full model

This slide is strictly for mathematicians…

- full constraint pricing on generation side ➡ $LRP_p = RRP - \sum_k (CSP_k * \alpha_{pk})$
- nominal CSC MW equals historical dispatch ➡ $CSCnom_p = DQHIST_p$
- CSC payments based on actual CSC MW ➡ $CSCpay_p = CSCact_p * (RRP - LRP_p)$
- actual CSC MW is scaled back from nominal ➡ $CSCact_p = scale_p * CSCnom_p \quad 0 \le scale_p \le 1$
- total CSC payments must not exceed intra-RSR ➡ $\sum_p CSCpay_p \le irsr$
- intra-RSR arises from intra-regional constraints ➡ $irsr = \sum_k CSP_k * RHS_k$
- "spot" gen payments based on the local price ➡ $SPOTpay_p = DQ_p * LRP_p$
- total gen payments = spot pay + CSC pay ➡ $GPAY_p = SPOTpay_p + CSCpay_p$
- no change to demand side ➡ $RPAY_l = MQ_l * RRP$

For clarity, loss factors not include. These are applied exactly as in the current regional model

*…but if a model fits on a single slide, it cannot be **too** complicated!*

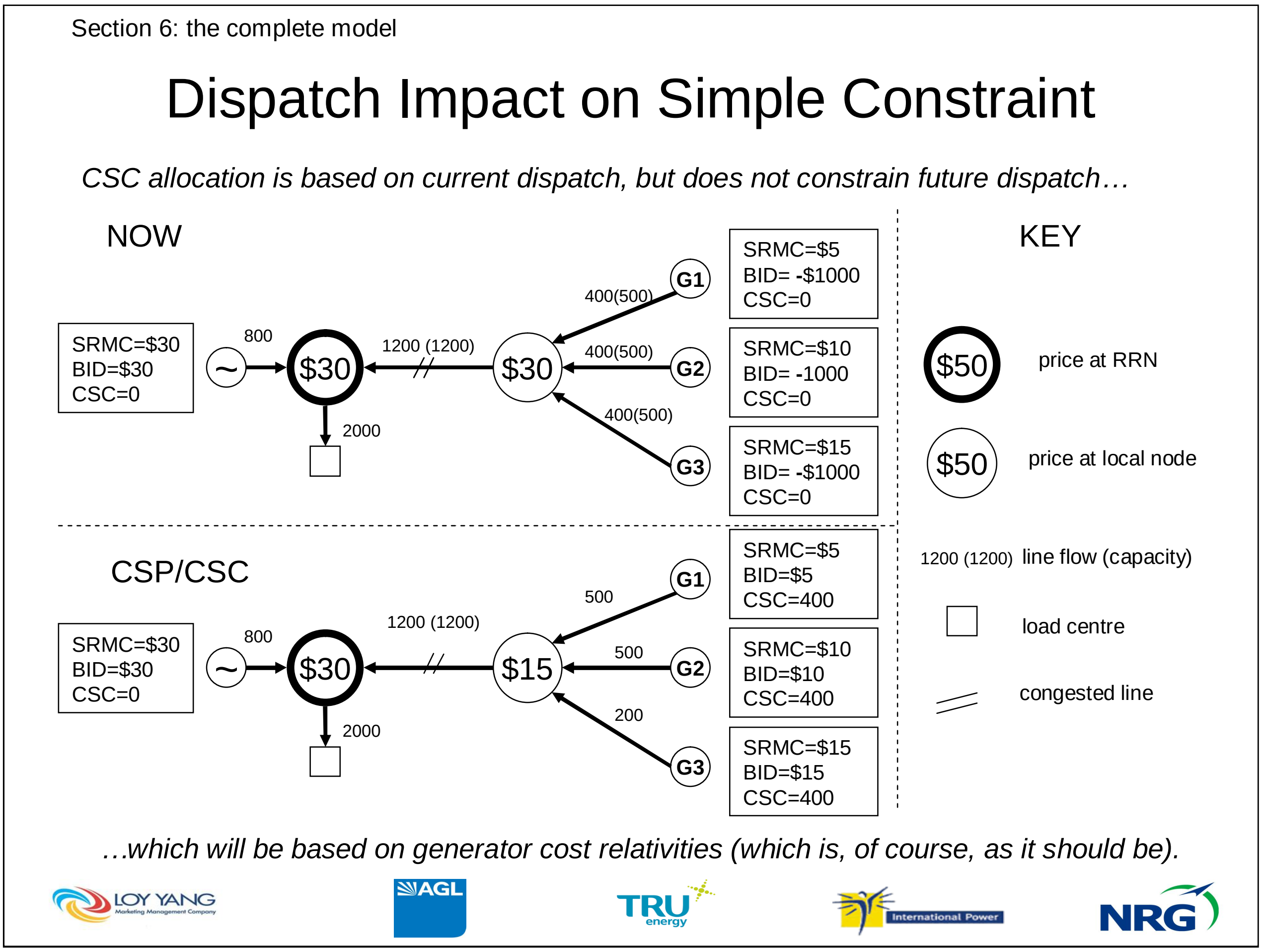
We believe our model is straightforward. It can be described on a single slide, as shown above. Of course, some complexity is not revealed here. This includes:

- the modelling of the system normal, peak demand, historical dispatch
- the formulation of the intra-regional constraints (already done by NEMMCO)
- the pricing of the intra-regional constraints (already done in NEMDE)
- the scaling back of nominal CSC amounts during transmission outages
- the allocation of CSC payments to interconnectors and SRA holders
- and…that's it!

A key to the variables and suffices used in the equations is provided below.

RRP	the regional reference price
LRP_p	the local reference price for power station p
CSP_k	the constraint support price (ie shadow price) of constraint k
α_{pk}	the coefficient applying to power station p in constraint k
RHS_k	the right hand side (constant term) in constraint k
DQ_p	the dispatch amount for power station p
MQ_l	the metered quantity in relation to a load, l

The meaning of the remaining terms should be clear from the context.



The diagram above expands upon the simple constraint example used earlier. Now included are the operating costs ("SRMC") and the bid prices of each generator. Also shown is generation at the RRN, whose SRMC sets the RRP.

Under current dispatch arrangements, when the constraint binds, all affected generators will bid as low as possible (-$1000) to avoid being constrained off. NEMMCO then "tie breaks" in proportion to capacity. These proportional dispatch quantities form the basis for CSC allocation.

In this example, the 3 generators have different SRMC and, once CSP/CSC is introduced, have an incentive to bid cost-reflectively. The result is that:

- firstly, the generators will be differentially dispatched according to their bidding order; and
- secondly, the local reference price falls to the bid price of the marginal generator behind the constraint.

As emphasised earlier, the CSC allocation does not constrain the dispatch solution; the two allocations are largely independent. Whilst it might be argued that no generator would wish to be dispatched below its CSC allocation, this could be addressed by the generators bilaterally trading CSC-derivatives to adjust their effective hedging position.

Section 6: the complete model

Financial Impact on Simple Constraint

CSCs do not stifle generation competition…

$000s	NOW	CSP/CSC
TOTAL RETAILER PAYMENTS	60.0	60.0
DISPATCH COST	36.0	34.5
TOTAL SURPLUS	**24.0**	**25.5**
shared between		
RRN GENERATOR PROFIT	0.0	0.0
G1 ($5/MWh) PROFIT	10.0	11.0
G2 ($10/MWh) PROFIT	8.0	8.5
G3 ($15/MWh) PROFIT	6.0	6.0
SETTLEMENT RESIDUE (to customers)	0.0	0.0
TOTAL	**24.0**	**25.5**

Gens see congestion price through CSPs → Gens bids better reflect costs → Dispatch cost is reduced → Trading Surplus Increases → CSCs “fix” gen profit at previous dispatch → Gens compete to receive the additional surplus

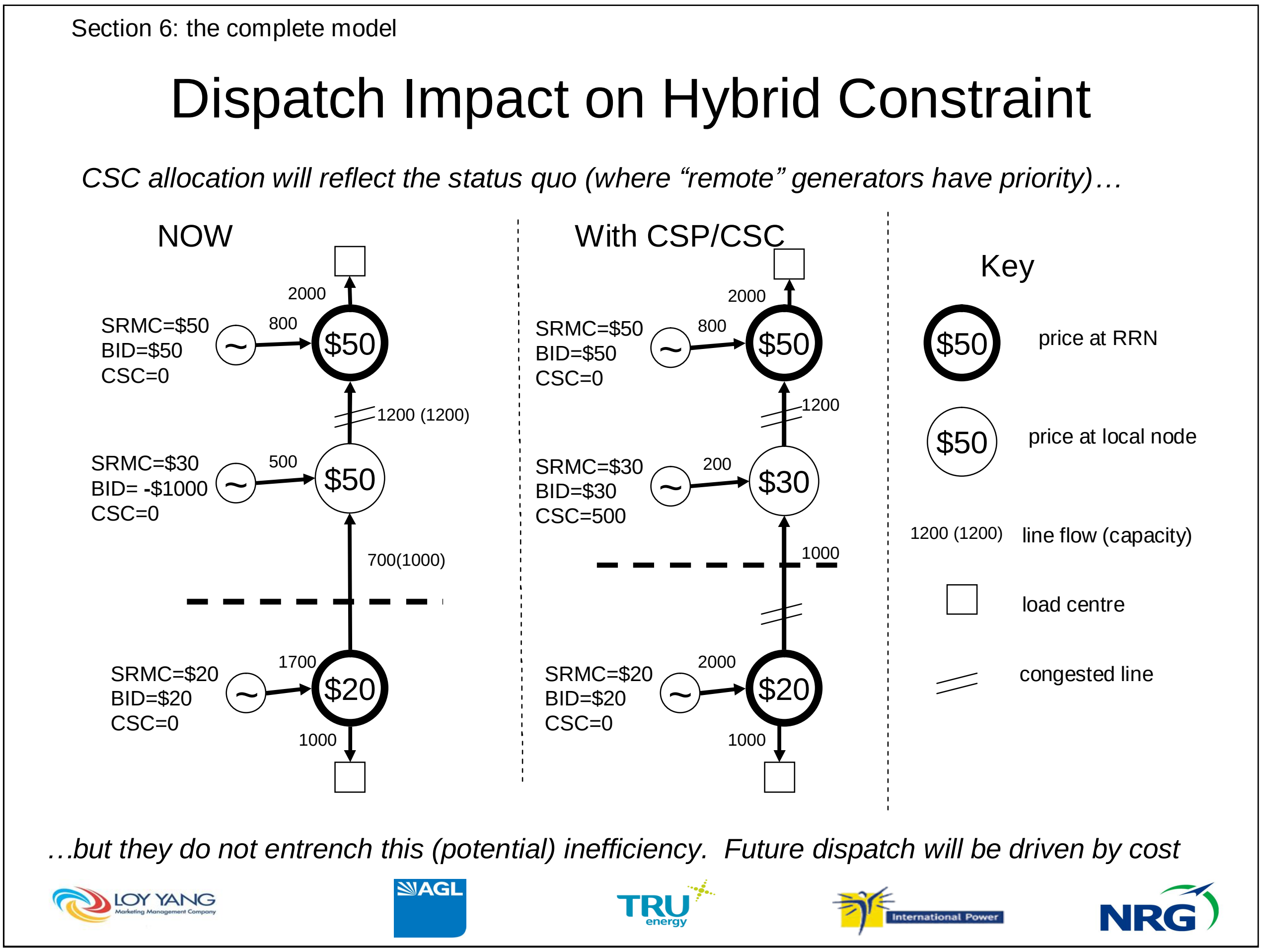
… but provide a platform upon which future competition takes place

This slide shows the financial impact of CSP/CSC introduction on the three generators. It looks at the size of the producer surplus – the difference between the total retailer payments to NEMMCO and the cost of dispatch (at SRMC) – and determines how this is allocated.

Because, in this example, it is assumed that the CSP/CSC has no effect on the RRP, the total retailer payments remain the same. However, dispatch cost goes down, as the lower-cost generator increases its output and the higher-cost generator decreases its output. Therefore, the producer surplus increases.

In both scenarios, the producer surplus is allocated between the 3 “remote” generators. However, in the second scenario, both the aggregate and distribution of the surplus change. Whilst the CSCs prevent any individual generator from being worse off, the distribution of the efficiency gains will depend upon the bidding and dispatch of the individual generators.

Thus, CSCs do not lock-in existing inefficiencies, nor do they stifle future competition. They simply protect generators from arbitrary and unmanageable loss of value over the transition to the new regime.



The diagram above shows a similar scenario to the hybrid constraint example provided earlier, but also expands this to show generation and load at the two RRNs and the bidding and SMRC of the three generators.

Currently, the “remote” generator will bid as low as necessary to avoid being “constrained-off” by the intra-regional constraint. CSCs are allocated to the remote generator and the interconnector according to this dispatch.

Under the CSP/CSC regime, the generator would no longer have an incentive to under-bid the interconnector and could be expected to bid closer to its SRMC (in fact, in this simple example, where it is the only generator, it could maximise profit by bidding just above $20, but in a more realistic example it would bid closer to $30 as shown). The interconnector then becomes fully utilised and constrained.

Dispatch efficiency has improved as 300MW of inter-regional generation costing $20 has replaced the remote generation costing $30.

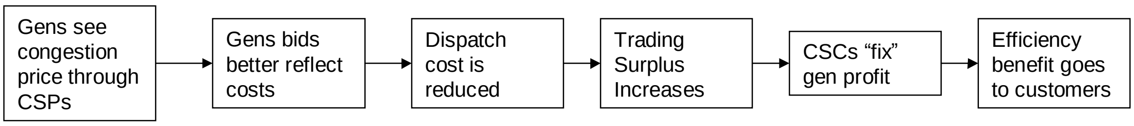
Although the two examples use simple, radial networks, broadly similar outcomes will arise on looped networks.

Section 6: the complete model

Financial Impact on Hybrid Constraint

CSCs protect generators from any downside, but the game is not “zero sum”.

$000s	NOW	CSP/CSC
TOTAL RETAILER PAYMENTS	120	120
DISPATCH COST	89	86
TOTAL SURPLUS	**31**	**34**
shared between		
“REMOTE” GENERATOR PROFIT	10	10
RRN GENERATORS PROFIT	0	0
SETTLEMENT RESIDUE (to customers)	21	24
TOTAL	**31**	**34**



Savings from dispatch improvements will generally flow to customers

The table above shows the commercial consequences of these two dispatch scenarios. As before, the producer surplus is the difference between retailer payments and dispatch costs. However, this surplus is now shared between the remote generator and the inter-RSR. Although the inter-RSR is distributed to SRA holders, the auction fees payable by these holders – which is paid to the relevant TNSPs and ultimately to customers – will reflect the level of the inter-RSR. In short, we can assume that in the longer term any changes to the level of inter-RSR are passed through to customers.

Although the remote generator’s local reference price and dispatch level has reduced, the allocated CSC protects it from any downside. However, the efficiency benefits are allocated in their entirety to the inter-RSR and thence to the customer.

In practice, generators will have varying degrees of market power and, as a consequence, may not necessarily bid at SRMC and may obtain a share of the efficiency benefits. However, as the local price is now transparent, any ongoing ability of the remote generator to maintain the local reference price above generating costs may, in time, attract new entrants. In the longer term, therefore, a large share of the efficiency benefits is likely to accrue to customers.

Section 6: the complete model

Evaluate full CSP/CSC against AEMC themes

We have previously evaluated are proposals against our own principles

		The Full CSP/CSC Model
Improve Certainty and Practicality	✓	The model provides a complete, comprehensive and stable congestion management regime. Once implemented – and once CSCs have been allocated – there is likely to be little need for future review or reform. CSC allocation and CSP calculation are simple and transparent to all participants
Facilitate Risk Management	✓	The regional forward markets are protected by preservation of current RRNs and RRPs and through CSP allocation, meaning that generators – like retailers – continue to have their primary exposure to these prices. The SRA process is largely unaffected, except that allocation of CSCs to interconnectors will prevent future negative settlement residues and provide some improved firmness to the SRA instruments. Simple and common terms for the CSCs means that these are also potentially "tradeable" as derivatives.
Ensure NEM Efficiency	✓	The model ensures that all constraints are priced to generators and there is no risk (as there is under the "gradual" model") that administrative delays may prevent timely creation of new CSPs. Thus improve static efficiency is ensured. Furthermore, a single, one-off allocation of CSCs to existing generators means that future generators will face the full cost of any congestion that they create. Thus, dynamic efficiency is also improved
Protect System Security	✓	The model is based around the "Option 4" constraint formulation, but could equally operate under a "full network model" if NEMMCO decided this needed to be introduced. The model places no limitations on NEMMCO introducing new or revised constraints – of any form – should the need arise.

…but our proposal also addresses all of the AEMC's objectives and concerns

In developing the model described in this report, we have been guided by the six principles previously articulated. In the table above, we return to the AEMC's four "themes" and evaluate our model against these.

Firstly, because the full CSP/CSC provides a complete and (long-term) sustainable model for congestion management – irrespective of where congestion may occur in the future – it removes the uncertainty that the market has faced for the last 8 years: around if, when or where new constraint prices (whether through region change or CSP) may be introduced.

The model may be comprehensive, but it is not complex. Indeed, we have shown how, operationally, it is much simpler than the "gradual" approach, in both the CSP and CSC elements.

The continuation of existing RRP pricing for retailers – together with CSC allocation for generators – ensures that the regional forward markets will continue to prosper and allow spot price risks to be managed.

NEM efficiency is ensured as *all* congestion – "material", "enduring" or occasional – is priced. In the short-term, this ensures price-based rationing of scarce transmission capacity. For the long-term, it provides efficient locational signals to new generation.

Last but not least, system security is protected, by allowing NEMMCO to get on with the job of formulating constraints that represent the physics of the power system, without constantly having to "look over their shoulder" to consider the commercial or policy implications.

Section 7: relationship with other areas of NEM reform

Relationship with other areas of NEM reform

We have developed our model in the context of congestion management…

- constraint formulation
  - model supports Option 4 formulation
  - could also operate under a full network model
- negative inter-regional SR
  - allocation of CSCs to interconnectors should prevent negative SR arising
- region boundary review
  - since constraints are priced for generation, the benefits of region change will be substantially reduced
  - in particular, region change will not affect generation dispatch
  - if region change were to occur, the CSCs could either be left as they are, or could be re-specified to reference the generators *new* local RRN
- TNSP performance incentives
  - a shortfall of transmission capacity is reflected in an ability of the intra-regional SR to "fund" the nominal CSC payments
  - thus, this "revenue inadequacy" is a measure of the impact of transmission outages on the market and could be used in any incentive arrangement
  - one approach could be to require the TNSP to make good a proportion of the inadequacy and so "firm up" the CSCs
  - however, this is speculative and does not form part of our current model
- Regulatory Test & LRPP
  - the model provides a faster and (generally) cheaper mechanism than transmission augmentation for managing intra-regional congestion and so makes timely transmission investment less critical
  - nevertheless, transmission investment can, should and will still occur when it is economic according to the Regulatory Test
- transmission pricing: Generation Side
  - the CSPs provide a long-run locational signal for new generation investment
  - this relieves much of the concern about the inadequacy of existing signals
- transmission pricing: demand side
  - if region change is less likely to occur (as is expected) then an alternative mechanism is required to provide locational signals to the demand side
  - this can be done through the appropriate design of TUoS pricing
- ancillary services
  - CRA suggested the possibility of extending the CSP/CSC model to network control ancillary services (NCAS)
  - this could be considered, once the "energy" CSP/CSCs are in place and participants are comfortable with them

…but it also provides a framework for considering and addressing other areas of NEM reform

As the AEMC notes, there are several NEM developments taking place in parallel with the congestion management review. *Not* coincidentally, most of these relate to different ways of managing congestion. They either deal with the side effects of unmanaged congestion (eg constraint formulation, negative IRSR) or search for other ways of dealing with it (Regulatory Test, LRPP, TNSP performance incentives, region boundary review)

With the full CSP/CSC model, we think that there will be:

- no business case for further region change;
- no future problems with negative inter-RSR;
- no contention surrounding constraint formulation;
- a reduced emphasis on transmission investment and the Regulatory test;
- a framework for considering the pricing and allocation of TUoS;
- a framework which can be potentially extended to network control ancillary services (as CRA originally proposed);
- a rationale for TUoS pricing to the demand-side: to provide the intra-regional locational signals that are missing from the spot market; and
- financial benchmarks – such as the extent to which CSC nominal quantities must be scaled back – against which TNSP performance can be measured

A "big picture" – a coherent model of NEM development – begins to emerge.

Conclusions

We think we have developed a compelling blueprint…

We have considered and evaluated the various design options available to address the problem of congestion management in the NEM. We have come to the view that the best way forward is a "full" CSP/CSC approach, which includes allocation of CSCs to existing generators, predicated on existing dispatch arrangements.

We have described our preferred model, at a high level, in this report. Doubtless, much work remains to develop and implement the model. We urge the AEMC to adopt our approach and to undertake this remaining work in the course of this congestion management review. We offer our full support in this process.

…the next stage is to build and implement

We have developed our proposals in accordance with the "themes" articulated by the AEMC which, ultimately, connect back to the NEM objective and economic efficiency. Whilst we would not deny that there are aspects of the model which are important to our own generation interests, we believe that implementing our approach will bring benefits to all sectors of the market and ultimately, of course, to the electricity consumer.

Of course, more work remains to be done and we have indicated in this report areas where some further analysis may be required. Doubtless, unexpected problems will emerge which will need to be addressed. However, in the light of the successful implementation of the Snowy Trial, we do not expect any "showstoppers". It is more a case of tailoring the high-level theory to the complex practicalities of managing an electricity spot market.

We hope that the AEMC will share our appreciation of the merits of our proposed model, will adopt it as the preferred approach, and will undertake with vigour the "heavy lifting" needed to develop and implement it. We offer them our full support in this task.