AUSTRALIAN ENERGY
REGULATOR

GPO Box 520
Melbourne VIC 3001
Telephone: (03) 9290 1444
Facsimile: (03) 9663 3699
www.aer.gov.au

Our Ref: 48613
Contact Officer: Mark Wilson

22 March 2013

Philip Weickhardt
Presiding Commissioner
Productivity Commission
Locked Bag 2 Collins Street East
MELBOURNE VIC 8003

Dear Mr Weickhardt

Submission on potential interim solutions to address disorderly bidding

Please find attached a supplementary submission from the Australian Energy Regulator (AER) regarding short term solutions to congestion issues.

This submission is further to a request from the Commissioners at the Productivity Commission's public hearing for the Electricity Network Regulatory Frameworks Review in Sydney in December 2012. As set out in the attached submission, the AER is supportive of a range of possible interim solutions being considered. The AER considers that the solutions that are likely to have the most merit in the short term would be a combination of, firstly, National Electricity Rule changes so that generators must bid in their technical ramp rate, and secondly, a review by the Australian Energy Market Operator (AEMO) of the minimum coefficients for interconnectors in transmission constraint equations. The AER also considers that a simplified congestion management mechanism should be considered as a priority. This could be a stepping stone to the full Optional Firm Access proposal being considered by the Australian Energy Market Commission (AEMC), or could be an effective stand alone mechanism that assists in addressing the concerns.

The AER would be pleased to provide further assistance to the Commission on this important area of work.

Yours sincerely

Andrew Reeves
Chair
Australian Energy Regulator

AER Submission

Possible options for interim solutions to congestion-related disorderly bidding

March 2013

Contents

1 What is congestion-related disorderly bidding?

In December 2012 the AER published a special report *"The impact of congestion on bidding and inter-regional trade in the NEM"*.[1] That report concluded that, over the last three years in particular, the increasing prevalence of disorderly bidding has created unnecessary price volatility, led to inefficient dispatch and created counter price flows across interconnectors. As a result, the ability of market participants to manage risk across interconnectors has reduced and with it competition between regions. This submission should be read in conjunction with attached special report.

The special report focussed on the impacts of inter-regional trade between Queensland, New South Wales and Victoria. Shortcomings in the market design incentivise disorderly bidding by generators when faced with being constrained. Network constraints can occur anywhere in the NEM and accordingly any interconnector, not just the Queensland to New South Wales interconnector and Victoria to New South Wales interconnector (VIC-NSW), is at risk of counter price flows precipitated by disorderly bidding. All regions have been impacted by disorderly bidding in the past.[2]

Disorderly bidding and counter price flows associated with congestion around Gladstone in Queensland has continued into 2013. In the first three weeks of January, for example, there were 80 occasions when the spot price exceeded $300/MWh, with 16 of those over $1000/MWh.[3] These price spikes were not driven by excessively high demand but rather network constraints and the last minute rebidding behaviour by CS Energy and Stanwell generators. Once again there have been persistent counter price flows from Queensland into New South Wales during the periods of high prices, leading to almost $8 million in negative settlement residues into New South Wales during January and February 2013. New South Wales customers ultimately pay for these negative settlement residues through charges for transmission.

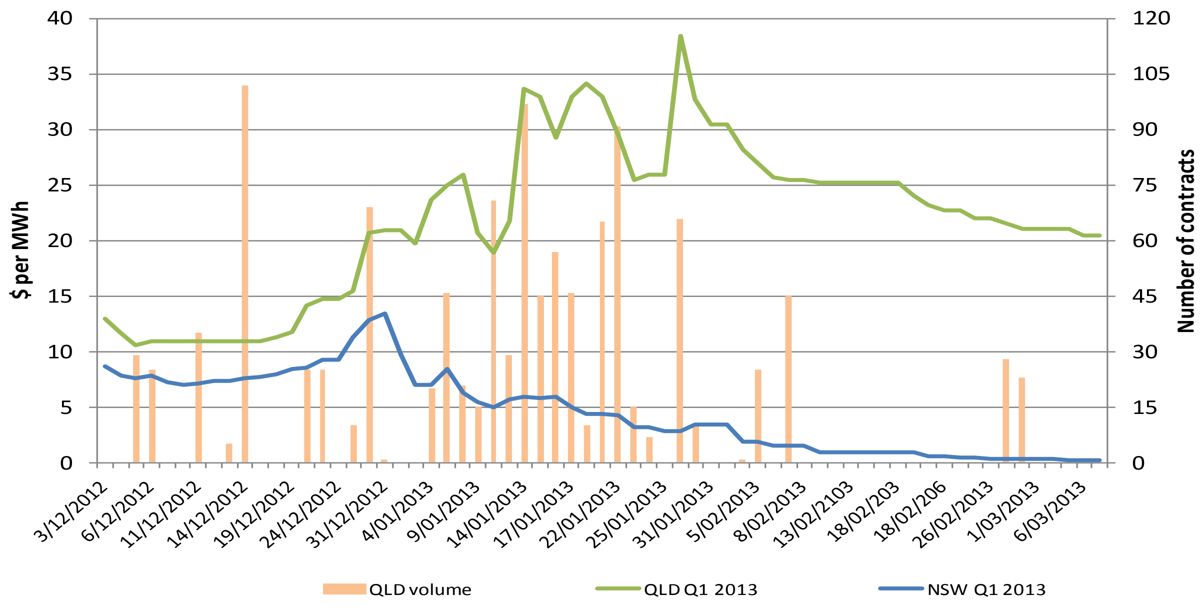
The impacts of these volatile prices are reflected in the value of the futures market in Queensland. The price of Queensland $300 cap contracts (i.e. the premium paid by the buyer to enter into the contract) for Q1 2013 diverged from the prices in other regions during the quarter. Figure 1 sets out prices for Q1 2013 $300 cap contracts for Queensland and New South Wales for comparison, along with the volume traded for the Q1 2013 Queensland caps, from December to early March.

1 The report is available at http://www.aer.gov.au/node/18855

2 Disorderly bidding by the Basslink Market Network Service Provider interconnector has led to it gaining an advantage over Victorian generators, which is the subject of a rule change currently under consideration by the Australian Energy Market Commission *"Negative offers from scheduled network service providers"*. Imports into South Australia can reduce following low priced bidding by South Australian generators located close to Victorian border.

3 In addition to these 80 spot prices, a further 36 prices above $300/MWh occurred as a result of tight supplies in Queensland or step changes in supply following large generator unplanned outages.

Figure 1: Prices for Q1 2013 $300 cap contracts on the ASX



Source: ASX/d-cyphaTrade www.d-cyphatrade.com.au

Disorderly bidding is an example of a prisoner's dilemma. In the event of network congestion, if one generator rebids capacity to very low prices and reduces the rate at which it can be ramped down, then its competitors must also do the same to avoid being constrained off more than would have otherwise occurred. This then leads to more volatile pricing and dispatch outcomes. The AER considers that disorderly bidding magnifies, and at times extends, the effects of congestion.

2 The costs of disorderly bidding

The AER considers that the outcomes associated with the recent disorderly bidding in Queensland illustrates some of the economic inefficiencies that can arise. During these events, high priced peaking plant running on liquid fuel was dispatched instead of lower priced coal plant (due to a combination of physical and economic withholding predominantly at coal power stations and/or generators being unable to be ramped up/down sufficiently due to low rates of change). In some instances, peaking plant were unable to respond quickly enough to unforecast high prices (at times set by strategically high priced coal plant) to run, which imposes costs on those market participants. Anecdotally the AER is aware that, in response to the frequency of unforecast high prices, some market participants ran peaking plant in anticipation of a high price (that did not always eventuate) or for periods longer and more frequently than that usually observed. The AER considers that the level of output from peaking plant in Queensland during these periods was unusual given the associated levels of demand.

However, the production inefficiencies associated with high-cost plant operating instead of lower-cost plant and counter-price flows on interconnectors are, in the AER's view, only one aspect of the costs associated with disorderly bidding. The AER considers that disorderly bidding caused by congestion can create very random large fluctuations in the price that are impossible to predict. This increases the risk profile of customers, retailers and generators. This higher risk profile is a cost which ultimately flows through to consumers through higher energy charges. The AER also considers that disorderly bidding greatly reduces the effectiveness of interconnectors, making it much harder for retailers or generators to hedge across region boundaries. This lowers the competitiveness of the wholesale market with longer-term flow on effects to efficiency and prices.

3 Possible long term solution

The Australian Energy Market Commission's (AEMC) Transmission Frameworks Review (second interim report) has recommended changes to the settlement of generators that are located at mispriced connection points through its Optional Firm Access (OFA) model. The AER welcomes the AEMC's work to develop the OFA proposal. It aims to address a range of important issues, including increasing the firmness of interconnector availability, in order to improve energy contract liquidity and competition. While the AEMC has made significant progress, there are many important areas of detail that are yet to be developed.

4 Possible interim approaches

As the AEMC is tackling a range of very complex issues, it is likely that any reforms will take a long time to implement. Therefore, the AER considers that, given the significant and pressing issues associated with disorderly bidding and resultant restricted or counter-price interconnector flows, interim changes should be implemented in the short to medium term to at least partially address the problem. These interim changes would mitigate the egregious cases of disorderly bidding, and improve firmness across interconnectors during high spot price events.

The list below provides a range of possible approaches that would assist in addressing the issue. The first approach addresses the market design issue. It could be a stepping stone towards the OFA model, or it could stand on its own as a solution to disorderly bidding even if the OFA model is never implemented. However, it is potentially controversial and so it may prove difficult to implement in the short term.

The other approaches aim to limit generators' response to some of the incentives the market creates rather than addressing those incentives. These approaches are simpler to implement requiring very little systems implementation, thereby allowing the most rapid introduction. However they are less effective and therefore less preferable.

The approaches are not mutually exclusive. The AER considers that adopting several of the different approaches would be optimal.

4.1 Approach 1: A simplified congestion management mechanism

One approach would be to introduce a simplified congestion management mechanism based on the Shared Access Congestion Pricing (SACP) model proposed in the AEMC's first interim Transmission Frameworks Review report. In the AER's submission to the first interim report we proposed a modified version of the SACP mechanism.[4] The SACP-like mechanism would be able to be implemented via relatively straightforward changes to AEMO's settlement systems. The mechanism could, in effect, be a stepping stone towards the full OFA model and would deliver significant gains. In particular, it could address much of the disorderly bidding problem, which would have flow on effects in terms of improving interconnector flows, the firmness of inter-regional hedges and with it improved competition across the market.

As a stepping stone towards OFA it would also provide valuable lessons to inform the design of the more complex aspects of the OFA model such as transmission network service provider (TNSP) incentive arrangements. It would also provide real world insights for generators prior to the requirement for those generators to choose whether or not to commit to firm access.

The SACP mechanism is relatively easy to implement from a technical perspective. However the allocation of rights to the intra regional settlement surpluses that accrue is contentious. The SACP

[4] AER *Submission to First Interim Report - Transmission Frameworks Review*, January 2012.

mechanism proposed allocation of access to settlement residues based on available generation capacity. However this results in low allocations for interconnectors when all available generation wishes to be dispatched (as evidenced during congestion events where very low or counter price interconnector flows occur). An alternative allocation that could improve the proportion of residues to interconnectors and therefore competition between regions would be to use annual average output for generators and average flow levels for interconnectors. The allocations could be determined annually by AEMO at the same time as transmission loss factors, which are required to be published by 1 April each year.

4.2 Approach 2: A greater restriction on generator ramp rates

A short term approach may include a greater restriction on generators lowering their ramp rates. At the moment, generators must specify a ramp rate that is 3 megawatts (MW) per minute or higher (or 3 per cent for generators less than 100 MW in capacity) unless there is a technical limitation on their plant. For large generators this is a very low ramp rate.

For example, Snowy Hydro's Tumut facility is treated as a single aggregated unit by the NEM dispatch engine, NEMDE, (despite being made up of 6 generation units) and has a maximum capacity of 1800 MW. If it is operating at 1800 MW (which it can reach from zero in less than 10 minutes with a ramp up rate of 200 MW/minute) and bids in a 3 MW/minute ramp down rate, it will take 10 hours to ramp down to zero output. Similarly, the 1500 MW Murray facility (with 14 generation units) is treated as a single aggregated unit by NEMDE.

The events of 22 April 2010 saw the price in Victoria exceed $5000/MWh for seven trading intervals. During the event there were 36 five-minute dispatch intervals where the five minute dispatch price in Victoria was close to the price cap. For every one of those dispatch intervals, the Murray generator was being constrained down from high output levels at 3 MW/minute. Murray's ramp down rate had been 200 MW/minute prior to the high price periods, which Snowy Hydro changed through a rebid. Counter-price flows across the VIC-NSW interconnector occurred for the entire period and resulted in $17.5 million of negative residues, the largest-ever single accrual of negative settlement residues.

The 3 MW/minute minimum requirement followed a proposal from the AER in 2008 to amend the relevant clauses of the National Electricity Rules (the rule became effective from January 2009).[5] Prior to this rule change, generators were able to offer or rebid ramp rates as low as 1 MW per minute. The level of 3 MW per minute was chosen as a compromise between the maximum technically possible and ensuring enough ramping capability was available to AEMO to manage system security.

The 3 MW/minute rule creates an advantage for large or aggregated generators that can significantly exacerbate the disorderly bidding problem. The AEMC's draft decision to change the relevant rules determined that ramp rates would apply to individual physical generating units.[6] Where physical generating units were aggregated, the ramp rates applicable to each separate generating unit were to be added together. In response to that draft decision, a number of participants with aggregated units responded that linking ramp rates to individual generating units placed a disproportionate burden on aggregated generators where a number of smaller generating units have been aggregated.[7] The AEMC's final decision, moved from its draft decision on aggregation to require a minimum ramp rate of the lower of 3 MW/minute or 3 per cent of the registered unit size to apply to both aggregated and non-aggregated generating units (as opposed to individual physical generating units). The AEMC stated that the risk of non-aggregated units applying to AEMO to become aggregated (in order to gain

[5] AEMC 2009, *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility,* Rule Determination, 15 January 2009, Sydney.

[6] AEMC 2009, *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility,* Rule Determination, 15 January 2009, Sydney.

[7] The participants were Snowy Hydro (14 units at Murray and 6 units at Tumut for example are aggregated for a combined capacity of 1500 MW and 1800 MW respectively), Hydro Tasmania and AGL (that each have a number of smaller aggregated hydro units).

this advantage) was mitigated by the requirement for AEMO to only approve aggregation if system security was not materially affected (clause 3.8.3(b)).

Aggregated generators, such as Snowy Hydro, which usually offer a ramp-down rate of 200 MW per minute rebid their ramp down rates to 3 MW per minute in the presence of congestion. This results in a disproportionate burden on other generators that are not aggregated – in contradiction to the equity argument put by Snowy Hydro (and others) in its submission to the AEMC's draft decision.

Approach 2A: One approach might be to change the minimum allowable ramp rate so that it would apply to individual physical generating units rather than aggregated units (consistent with the AEMC's draft decision). This would increase the minimum ramp rate for a number of large units (in particular Murray and Tumut, which are the largest units in the NEM) and reduce the prevalence of counter price flow resulting from disorderly bidding.

Approach 2B: The AER has considered whether the Electricity Rules should be changed to additionally require that when a network constraint binds, each generator on the left hand side (LHS) has to bid in their maximum technical ramp rate. Evidence of rapid rebidding that occurs in response to congestion (with congestion given as the reason), suggests that generators are fully aware when a network constraint is binding. Such an approach would also assist system security as NEMDE would be able to select the most effective method of addressing congestion in the network.

The disadvantage of this approach is it requires generators to rebid once they become aware a constraint is binding. There is a question of how long a generator would need to maintain the ramp rates at the technical limit level. In a worst case scenario, the rebidding of ramp rates could alleviate the constraint such that it no longer binds. If generators then rebid ramp rates back to their previous level, in some circumstances this could trigger a circular situation where the same constraint starts binding again within a short time frame.

Approach 2C*:* A further alternative would be to change the Electricity Rules so that generators must specify a ramp-rate of at least a certain percentage (say 3 per cent) of their capacity (unless there is technical limitation on their plant). This would lower the inefficiencies caused by disorderly bidding. A minimum of 3 per cent per minute ramp-rate would mean that any generator could be ramped down to zero in around 33 minutes (subject to technical limitations).

The disadvantage of this approach is that it represents a large increase in the minimum ramp rate for the larger thermal generators to a level possibly beyond their technical capability. For example, the 560 MW brown coal Loy Yang A units would be required to increase their ramp rate to 16 MW/minute, which is above their technical capability, so the (lower) technical limitation based ramp rate would have to apply. Therefore many units may be affected by this change and would be required to operate at their technical limitation based ramp rate. This led the AER to consider approach 2D.

Approach 2D*:* A final ramp-rate related rule change approach the AER has considered is to require generators to bid a technical ramp rate at all times. Arguably this is just a refinement to meet the original intent of the 2008 rule change, which separated the commercial parameters of a bid (price and availability, which are both required to be rebid in "good faith") from the technical parameters of a bid (ramp rate, dispatch inflexibilities and frequency control ancillary services trapezia). The reason for this is that generators can utilise the commercial parameters of a bid to determine their desired output. On the other hand NEMDE treats all technical parameters, including ramp rates, in the same way and honours them under almost all circumstances, including by violating network constraints. However, the current actions by generators during disorderly bidding utilise the ramp rates to reduce the effect of congestion on their output for commercial purposes. This creates a situation whereby generators can use a technical element of a bid to achieve a commercial outcome. This conflict in the role of ramp rates must be resolved.

One potential disadvantage of this approach is the possible incentive to "de-engineer" the plant and reduce the technical ramp rate capability. However the likelihood of this perverse outcome is low. For most of the time (apart from periods of local congestion leading to disorderly bidding) generators have an incentive to maintain flexible plant that can respond quickly to high or low prices.

Recognising that the technical ramp rate of plant is not always precisely definable, and to reduce the regulatory uncertainty of this rule change, the definition of technical ramp rate would need to be specified by the AER. The Electricity Rules could therefore require the AER to publish guidelines on this definition and how it would monitor compliance with the obligation to provide a technical ramp rate at all times. If a generator materially changes its ramp rate then the generator would be required to rebid and provide the reasons to AEMO. The AER should be entitled to require that the generator provide additional information to substantiate and verify the reason provided, as is currently the case when generators specify a ramp rate below 3 MW/minute (see 3.8.3A).

4.3 Approach 3: A review of constraint formulation guidelines

In the AER's special report on congestion we explain how transmission constraint equations operate. There is a threshold below which it is deemed that variable inputs, including generators and interconnectors, will not be included in the LHS of constraint equations. The purpose of the threshold is to exclude those inputs, such as the output of a generator, whose variance would not materially enhance system security due to the size of their coefficient. This threshold is determined by AEMO in its Network Constraint Formulation Guidelines.[8] The guideline specifies that if an input has a coefficient of less than 0.07 then it will not be optimised or controlled, but its output will be taken as given (as determined by normal economic dispatch).

The threshold was determined by AEMO calculating the smallest coefficient for a generator (the relevant generator) below which a small change in the output of one generator would require an unacceptably large swing in the output of a small coefficient generator on the same constraint. No specific consideration, however, was given to interconnectors, which can change rapidly. The same threshold for generators and interconnectors was used for consistency reasons only.

It is worth emphasising that including smaller coefficient terms in constraint equations has a perverse outcome in that, in the presence of disorderly bidding, the generators and interconnectors with the least impact on the constraint are moved the most. This can lead to rapidly changing levels and direction of interconnector flows, five-minute dispatch prices and output from individual generators. Many of the most egregious events (particularly the New South Wales events involving the western Sydney 70/71 lines and the Gladstone congestion in Queensland) result from very small coefficients, with interconnectors being moved many multiples of the volume of plant that was moved by disorderly bidding. The threshold selection involves a trade off, in that more controllable terms (i.e. the lower the threshold) should in theory result in more secure dispatch, but in the presence of disorderly bidding it results in less efficient and more volatile dispatch.

Consideration should be given to AEMO reviewing the constraint formulation guidelines to assess whether a different minimum threshold should be applied to determine if interconnectors are co-optimised. This could prevent rapid changes in interconnector dispatch outcomes that result from network congestion that is remote from the interconnector. Such a change would assist in addressing the changes on interconnectors where the interconnector is only a minor contributor to the congestion (such as for the Queensland congestion issues around Gladstone, and the New South Wales congestion issues around western Sydney). However, it would not solve counter price flows between Victoria and New South Wales that occur as a result of disorderly bidding by Snowy Hydro, as the VIC-NSW interconnector has a high coefficient. (In other words, because the VIC-NSW interconnector

[8] See: http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Dispatch/Constraint-Formulation-Guidelines

will always have a high coefficient, changing the minimum threshold will not alter the constraint equation).

There is a potential risk to system security if interconnectors are not co-optimised. This is because NEMDE will not be able to change the interconnector flow to resolve the constraint and therefore have fewer options available to it. However, this proposal would only apply to congestion that is electrically remote from the interconnector (as evidenced by the small coefficient), which would be readily resolved through changing the dispatch of generators close to the constraint. The current arrangements, where rapid changes in output from many generators and interconnectors results in large swings in power flows and voltage levels, also has the potential to cause power system instability.

If approach 3 were to be combined with approach 2D, NEMDE will have significantly improved ability to resolve congestion issues by changing the dispatch of generators close to the constraint (given the changes to ramp-rates proposed in approach 2D), which would therefore alleviate any security concerns arising from introducing approach 3.

The AER accepts that approach 3 would be a complicated piece of work for AEMO, as security of the system may need to be trading off against efficiency benefits. It would most likely take some time to implement. However, once the Network Constraint Formulation Guidelines were amended, reformulating individual constraint equations (for example, certain constraint equations in Queensland) could be done quickly.

Special Report

The impact of congestion on bidding and inter-regional trade in the NEM

December 2012

AUSTRALIAN ENERGY REGULATOR

Inquiries about this report should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001
Tel: (03) 9290 1444
Fax: (03) 9290 1457
Email: AERInquiry@aer.gov.au

AER reference: 48613 - D12/169524

Introduction and Summary

This report outlines the current National Electricity Market (NEM) arrangements for managing transmission network congestion and how generators respond to that congestion. It analyses how generators' response to congestion has led to inefficiencies, price volatility and has reduced the ability for market participants to manage risk between regions. The analysis focuses on recent congestion events in Queensland, New South Wales and Victoria. The analysis shows how the prevalence of congestion can be increased through generator rebidding (known as 'disorderly bidding').

We conclude that the current arrangements are leading to significant inefficiencies and lessening competition between regions. The AER considers that incentives for disorderly bidding are a serious problem with the current NEM design. While the optional firm access model proposed in the Australian Energy Market Commission's (AEMC) *Transmission Frameworks Review* should address the concerns, those reforms will take a long time to implement. We recommend fast tracked changes to protect the integrity of the market in the interim. Such changes could include changes to the arrangements for settlement of generators or changes to the bidding rules. In addition, we consider that the Australian Energy Market Operator (AEMO) should review how interconnectors are treated in the *Network Constraint Formulation Guideline*.

The AER has reported on the impacts of congestion and disorderly bidding in many past reports, including its $5000/MWh reports and weekly electricity reports.[1]

Congestion in the NEM

Transmission networks transport electricity from generators to large customers and load centres served by distribution networks. Transmission networks also connect different regions, allowing for the interregional flow of electricity in the NEM.

Congestion occurs when the incremental increase in the amount of electricity that can flow over a particular line or other transmission system element is constrained by physical or system limitations.[2] These limitations usually reflect the ratings of transmission equipment (generally referred to as 'lines' in this report). The ratings of transmission lines are not always constant and are affected by ambient weather conditions.

Congestion impacts on market participants and market outcomes by distorting the economic dispatch of generators and hence market price outcomes. Despite these impacts, a certain level of congestion is expected in an efficient market where the cost of expanding the network to eliminate congestion is greater than the cost of congestion.

[1] For example, see the 7 December 2009 $5000 report when rebidding by Snowy of capacity at Tumut and Upper Tumut into low prices led to counter-price flows into Victoria, which is published at www.aer.gov.au.

[2] Under the National Electricity Rules (the Electricity Rules), AEMO is required to operate the power system in a secure state. This means that the power system is operated such that it is able to withstand a credible contingency without damaging or destabilising the power supply.

Management of constraints

Constraint equations

One of AEMO's responsibilities as the market and system operator is to manage the network to ensure that transmission elements are not overloaded and system security is maintained. Where transmission elements become congested, they are referred to as being constrained. To manage network flows AEMO utilises constraint equations in the NEM dispatch engine (NEMDE), which runs every five minutes. A constraint equation is used to determine the optimal dispatch of generators based on their offers (or bids) to manage flows on specific transmission lines (and other equipment) for each five minute dispatch interval.

Each constraint equation consists of a Left Hand Side (LHS) and a Right Hand Side (RHS). The RHS signifies the outer point of an outcome, beyond which a line could become overloaded in the event of the 'credible contingency' the constraint is designed to manage.[3] A 'credible contingency' includes, for example, the loss of another line or a generator. The RHS contains all of the inputs that cannot be varied by NEMDE. These inputs include demand and the rating of the relevant transmission line (i.e. how much energy the line can carry without damaging the line or causing unsafe conditions). The LHS contains all of the inputs that can be varied by NEMDE to deliver an outcome that satisfies the requirement of the RHS. These inputs include output from generators and flow on interconnectors.

How NEMDE deals with constraints

Constraint equations are used in NEMDE together with generator bids to determine the optimal economic dispatch of generators to meet customer demand. All else being equal, if the flow over a particular element of the transmission system is within the requirements of the RHS, then the relevant constraint equation does not affect NEMDE dispatching generators in accordance with 'merit order' or 'economic dispatch' (by 'merit order' or 'economic dispatch' the AER means least-price offers of generation capacity are dispatched first). When the LHS of a particular constraint equation is equal to the RHS, the constraint is considered to be at its limit and is 'binding'. In this situation, NEMDE may need to affect dispatch outcomes to satisfy the constraint in preference to economic dispatch.

NEMDE is designed to avoid or minimise violating a constraint equation. Violations occur on the rare occasion when the LHS is greater than the RHS; that is, the flow over the line could be greater than its rating if the relevant credible contingency occurs in the next five minutes.[4] A binding constraint equation affects dispatch until the constraint no longer binds.[5]

To control the flow over a bound line to avoid violating the constraint, NEMDE attempts to change the LHS inputs. For example, NEMDE may try to increase (out of merit order) the output of generators or interconnectors closer to a relevant load/demand centre ('constrain on' a generator or interconnector). By increasing generation closer to the load/demand, it can in effect reduce the congestion on the transmission system. Alternatively, NEMDE can reduce (out of merit order) the output of generators or interconnectors that are a source of the flow over the transmission line ('constrain off' a generator or interconnector). NEMDE may also adopt a combination of these actions, depending on the specific constraint equation that is binding.

---

3 If the constraint equation is not satisfied it is termed as 'violated'.

4 Constraint equations can be expressed as LHS ≤ RHS or LHS ≥ RHS. For the purposes of this report, the descriptions of constraint equations are limited to LHS ≤ RHS. These are the most common types of constraint equations used to manage network limits.

5 The constraint may stop binding due to for example an increase in line rating (which can be influenced by ambient weather conditions) or changes in generator offers.

While the priority is system security and avoiding violations of constraints, NEMDE still attempts to find the least cost way of dispatching generation out of the options available. Therefore if, for example, there are several generators that could be ‘constrained on’, it will choose the lowest cost combination taking into account the prices offered and the coefficients (see discussion of coefficients below). The ability of the system to change generator outputs and interconnector flows to manage network congestion is termed ‘fully co-optimised dispatch’ (see Appendix A).

When NEMDE changes flows over an interconnector (by ‘constraining on’ or ‘constraining off’ an interconnector), NEMDE changes the output of generators in adjoining region(s). This does not involve constraining particular generators, rather NEMDE reduces or increases the level of supply that is sourced from interstate generators.

Coefficients in constraint equations

As was noted earlier, the LHS of constraint equations contain all of the inputs that can be varied by NEMDE to avoid violating the constraint, such as output from generators and flow on interconnectors. Each generator or interconnector on the LHS has a coefficient, which reflects the impact it has on the constrained transmission line. In other words, the effect of a one megawatt (MW) change in the output of a particular generator (or flow on a particular interconnector) on flows over the constrained line is reflected in the coefficient assigned in the LHS. For example, if a one MW reduction in output of a generator decreases flow on the constrained line by one MW, the coefficient is +1. A positive coefficient means that a generator may be ‘constrained-off’ when the constraint binds, while a negative coefficient means a generator is ‘constrained-on’. The further away a generator or interconnector is located from the constrained line, the greater the change in output required to achieve a one MW change in flow over the constrained line. This is reflected by a smaller coefficient.[6]

There is a threshold below which it is deemed that variable inputs, including generators and interconnectors, will not be included in the LHS of constraint equations. The purpose of the threshold is to exclude those inputs, such as the output of a generator, whose variance would not materially enhance system security due to the size of their coefficient. This threshold is determined by AEMO in its *Network Constraint Formulation Guidelines*.[7] The guideline specifies that if an input has a coefficient of less than 0.07 then it will not be optimised, but its output will be taken as given (as determined by normal economic dispatch).

The threshold was determined by AEMO calculating the smallest coefficient for a generator (the relevant generator) below which a small change in the output of one generator would require an unacceptably large swing in the output of a small coefficient generator on the same constraint. No specific consideration, however, was given to interconnectors, which can change rapidly as set out below. The same threshold for generators and interconnectors was used for consistency reasons only.

[6] Note that coefficients are normalized, which means that sometimes a coefficient of 1 may not mean a 1 MW change in flows on the constrained line, but a generator or interconnector with a coefficient of 1 has the largest impact.

[7] http://www.aemo.com.au/en/Electricity/Market-and-Power-Systems/Dispatch/Constraint-Formulation-Guidelines

Technical limitations when constraining on/off

As noted earlier, when a constraint binds NEMDE tries to find the optimal outcome (which prioritises the dispatch of low priced generation) to manage the constraint. A further requirement NEMDE must incorporate is adherence to the technical limitations of the relevant generators. When submitting offers, generators have to specify the rate at which their plant can increase or decrease the level of output in MW per minute. This rate of change is referred to as the ramp rate. Generators must specify a ramp rate that is 3MW/minute or higher unless there is technical limitation on their plant.[8] An interconnector is treated as having no ramp rate and therefore NEMDE can rapidly change the level and direction of flows on interconnectors.

Disorderly bidding

Incentives for disorderly bidding

When a constraint equation binds, NEMDE dispatches constrained generators out of merit order. In other words, there will not be economic dispatch because not all low priced capacity will be dispatched, with some higher priced capacity dispatched in preference. A constrained-on generator may be dispatched at a price that is lower than the price at which it offered its capacity.[9] A constrained-off generator may be dispatched at levels that are below its desired level given the price. The desired level of output for a generator often reflects its hedge market contractual obligations. If a generator cannot generate to cover its contractual position, it risks losing significant revenue.

AEMO publishes information in pre-dispatch systems that forecasts demand levels, price outcomes and dispatch targets for generators. AEMO publishes two pre-dispatch forecasts, one on a half hourly resolution every half hour for the remainder of the trading day and a five minute pre-dispatch forecast on a five minute resolution for the next hour ahead. This enables generators to identify the likely impact of forecast binding constraints on their plant.

Generators that are forecast to be constrained have an incentive to rebid their capacity in order to limit the impact of a binding constraint on their dispatch outcomes. Generators with a negative coefficient can rebid capacity into higher price bands and/or as unavailable to reduce the possibility (or the magnitude) of an increase in output as a result of being constrained-on.[10] Generators with a positive coefficient can rebid capacity into negative price bands to reduce the extent to which their dispatch levels will be decreased. As NEMDE is seeking to manage the constraint most optimally (based on generator offer prices as a proxy for cost), rebidding capacity in this way will influence NEMDE's outputs.

---

[8] The minimum ramp rate for generators with a capacity less than 100MW is equivalent to 3 per cent of capacity per minute. This rule requirement followed a rule change proposal from the AER in 2008 (the Rule became effective from January 2009). Prior to this rule change, generators were able to offer or rebid ramp rates as low as 1 MW per minute. The level of 3 MW per minute was chosen as a compromise between the maximum technically possible and the minimum of zero.

[9] Under clause 3.9.7(a) of the Electricity Rules, the dispatch offer of a generator that is 'constrained-on' may not be taken into consideration when determining the dispatch price for the relevant dispatch interval.

[10] If a constrained-on generator is bid unavailable AEMO can direct the generator on to assist with managing security. This occurs rarely, but in this case the directed generator is compensated based on costs incurred.

Generators can also rebid to change their technical parameters such as ramp rates to limit the rate and extent to which their existing output levels can be decreased or increased. Generators with a negative coefficient can rebid to reduce the ‘ramp up’ rate to reduce the possibility (or the magnitude) of an increase in output as a result of being constrained-on. Generators with a positive coefficient can rebid to reduce the ‘ramp down’ rate to reduce the extent to which their dispatch levels would be decreased. When generators rebid their ramp rate, NEMDE may have to constrain other generators or interconnectors in order to satisfy the constraint.

This type of bidding, when the network is constrained, is referred to as ‘disorderly bidding’. By engaging in disorderly bidding, generators are seeking to influence what outcomes NEMDE will choose to manage the constraint.

Impacts of disorderly bidding on generators and price

Disorderly bidding can serve to increase the number of generators that have to be constrained in order to manage the constraint. Where generators that are closest to the constraint (those that have the largest coefficient and therefore have the greatest impact on relieving the constraint) engage in disorderly bidding, NEMDE may have to constrain generators and interconnectors that are further away from the constraint to a greater extent than what it would otherwise have done. Remote generators and interconnectors with smaller coefficients are constrained to a greater extent than generators closest to the constraint in order to achieve the same outcome.

Disorderly bidding can also increase price volatility in the affected region(s). When a constraint binds, regional prices can increase rapidly as NEMDE dispatches higher cost generation to prevent violating the constraint. In situations where constrained-off generators rebid capacity to negative price bands to increase dispatch, the price can drop to negative levels when the constraint ceases to bind (due to the large quantity of capacity shifted to negative prices).

Disorderly bidding can then initially lead to spot prices significantly higher than that forecast, with some peaking generators having insufficient time to react to ensure they are dispatched to cover their contractual obligations, and then the price can fall significantly.

Impacts of disorderly bidding on interconnector flows

Congestion can also cause counter-price flows on interconnectors. In the normal course of events, electricity will flow from low priced regions across interconnectors into higher price regions. Counter-price flows occur when electricity is exported from a high price region into a lower priced region in order to manage congestion. This occurs when NEMDE determines that the optimal outcome to manage congestion located in one region is to force the flow of electricity into an adjoining region. This possibility is enhanced by the fact that interconnectors have no ramp rates, which allows for the flow of electricity over interconnectors to be changed very quickly.[11]

Counter-price flow on an interconnector is commonly caused by disorderly bidding by generators close to an interconnector, which is discussed further in the *Examples of disorderly bidding* section.

[11] The rate of change for the interconnector is limited only by the aggregate ramp rate of all generators on the other side of the interconnector.

Inter-regional settlement residues

Inter-regional settlement residues occur when the prices between regions separate. Generators are paid at their regional spot price while retailers pay the spot price in their region. The difference between the price paid in the importing region (by retailers) and the price received in the exporting region (by generators), multiplied by the amount of flow across the interconnector, is called a settlement residue. The rights to these residues are auctioned by AEMO in settlement residue auctions (SRAs). (See the *Interconnector flows and SRAs* section of this report).

When a counter-price flow occurs, however, AEMO has paid out more money to the generators in the exporting region than it has received from customers/retailers in both the exporting and importing regions. This is known as negative inter-regional settlement residue. The cost of funding these negative residues falls on the relevant transmission network service provider (TNSP) in the importing region. The TNSP recovers this expense through higher network service fees.[12]

AEMO is required under the rules to use reasonable endeavours to manage the accumulation of negative inter-regional settlement residues when the accumulation reaches $100 000. This is achieved by invoking constraints on interconnectors to limit or ‘clamp’ exports from the high priced exporting region into adjoining region(s). At times this is ineffective (with counter-price flows continuing to occur) as power system security (the management of network elements and generator technical parameters such as ramp rates) takes precedence over the management of counter-price flows. Even when clamping is successful and counter-price flows are reduced to zero, there are market inefficiencies as there are zero imports into the high priced region, which means that the return to SRA unit holders is zero.

[12] The proceeds of SRAs are paid to TNSPs, which then reduces the transmission use of system (TUOS) payments charged to the TNSP’s customers. Negative settlement residues reduce the SRA proceeds that otherwise offset TUOS payments.

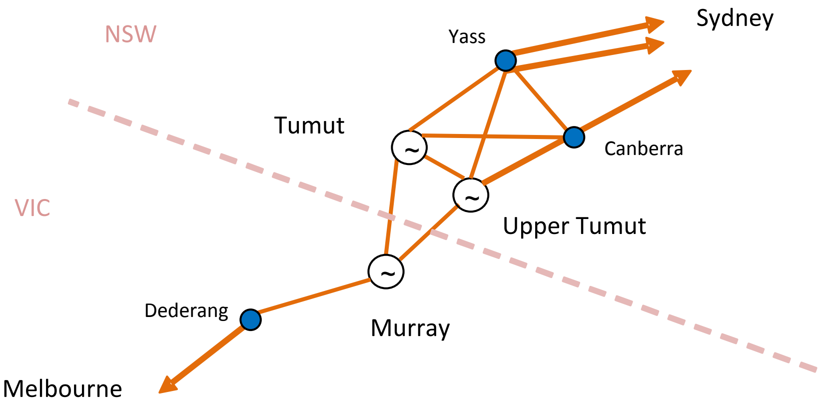
Examples of disorderly bidding

Congestion around Snowy – counter price flows into Victoria or New South Wales

The Snowy situation is one example of how disorderly bidding by participants in response to constraints can materially impact on spot price outcomes and interconnector flows between New South Wales and Victoria.

Snowy Hydro owns and operates a number of hydroelectric power stations, including Murray, Tumut and Upper Tumut, which straddle either side of the Victoria – New South Wales region boundary. Murray is located in the Victorian region, while the Upper Tumut and Tumut generators are located in the New South Wales region. Murray's pathway to major Victorian load/demand centres is southwards on the Murray-Dederang 330 kV transmission lines. Tumut and Upper Tumut are linked to major New South Wales load/demand centres northwards by three main transmission pathways. This is illustrated in Figure 1.

Figure 1: Simplified transmission network around the Snowy generators



The Murray and Tumut generators have a combined maximum summer rating of just under 4000 MW. Due to their size and position, the Murray and Tumut power stations effectively act as gatekeepers for cross border flows, in that their output strongly influences the direction of flow between New South Wales and Victoria. During periods where transmission lines between the Snowy generators and Melbourne or Sydney load centres are constrained, Snowy Hydro has the ability to rebid the capacity of its Murray and Tumut generators, to maximise its own dispatch. However, this often causes the counter-price flow of electricity from the high-price region into the low-priced region. Other generators close to Snowy Hydro, in particular Origin Energy's Uranquinty station, also contribute to counter-price flows into Victoria. [13]

Two recent examples reported in AER weekly reports of counter-price flows into Victoria and into New South Wales are outlined below.[14] However, these are not isolated examples, with 20 similar occasions since December 2009 when disorderly bidding by Snowy Hydro has led to significant counter-priced flows between Victoria and New South Wales.

---

[13] Uranquinty is located, in an electrical sense, very close to the Tumut generator.

[14] The AER is required under the Electricity Rules to determine whether there is a significant variation between the forecast spot price published by AEMO and the actual spot price and, if there is a variation, why the variation occurred. The AER publishes weekly reports that provide this analysis. Further information is provided when the spot price exceeds three times the weekly average and is above $250/MWh or less than -$100/MWh.

16 October 2012 – counter price flows into Victoria

An example of counter-price flows from New South Wales into Victoria occurred on 16 October 2012. At 5.05 am constraints to manage the planned outage of the 330 kV Dapto to Marulan line in New South Wales were invoked.[15] The Dapto to Marulan line is between the Sydney load centre and the southern New South Wales generators (including the Tumut generators). This meant that to manage the network constraint, the southern generators needed to be reduced in output and/or the VIC-NSW interconnector needed to flow southwards.

At 1.58 pm, rebidding by generators in New South Wales saw the forecast price for 3.30 pm to 5 pm increase from around $60/MWh to $290/MWh. Following the increase in the forecast price, Snowy Hydro and then Origin Energy rebid over 3100 MW, the total capacity of generation in southern New South Wales, to prices near the price floor:

- Over 8 rebids between 2.12 pm and 3.49 pm a total of 2520 MW of capacity at Tumut, Upper Tumut and Guthega (another Snowy Hydro generator in the region) was shifted by Snowy Hydro from prices above zero to close to the price floor. This resulted in the start up of the Tumut generator, which was generating 1800 MW by 4 pm. The rebid at 2.46 pm also reduced the 'ramp down' rate of the three stations to the minimum allowed of 3 MW/min. The rebids were effective immediately. The reasons given for the rebids related to congestion on the Dapto to Marulan line.

- Following the very large rebids into negative prices by Snowy, NEMDE forecasts showed a significant reduction in the output of all four Uranquinty generators, which were already running at full output. Origin Energy rebid 240 MW and 664 MW of capacity at Shoalhaven and Uranquinty, respectively, from prices above $47/MWh to close to the price floor. This resulted in the start up of the Shoalhaven generator, which was generating 240 MW by 3.25 pm. The rebids were effective from 3.05 pm and 3.10 pm and the reason given related to management of the congestion on the Dapto to Marulan line.

At 2.50 pm the constraint managing the planned outages bound. The large negative rebids for the Snowy Hydro and Origin Energy generators saw the output from their generators increase by 1200 MW and 200 MW respectively. As a result the flow across the Victoria to New South Wales interconnector changed from imports of 706 MW into New South Wales to forced counter-price exports by 3.10 pm, reaching 875 MW into Victoria by 3.25 pm.

To manage (or 'clamp') the accrual of negative residues as a result of the counter price flows AEMO invoked a further constraint. This commenced reducing flows into Victoria from 3.50 pm, with flows reaching zero by 4.20 pm. This required the output from a number of generators south of the constraint to reduce:

- Tumut (Snowy Hydro), which commenced generating at 2.10 pm and reached 1800 MW at 3.30 pm, reduced from 1797 MW to 1760 MW (at 3 MW per min);

- Upper Tumut (Snowy Hydro) reduced from 652 MW to 577 MW (at 3 MW per min);

- Guthega (Snowy Hydro) reduced from 53 MW to zero (at 3 MW per min);

- Uranquinty (Origin Energy) reduced from 644 MW to 461 MW;

[15] The 330 kV Liddell to Tomago line was also taken out of service at the same time. This outage had a minor impact on flows from Queensland to New South Wales, reducing imports into New South Wales.

- Shoalhaven (Origin Energy), which commenced generating at 3.10 pm and reached 244 MW at 3.30 pm, reduced to 202 MW. At 4.05 pm Origin Energy rebid to reduce the ramp down rate to zero, which meant that its dispatch could not be reduced. The reason given was that it could not be further reduced as it had reached its technical minimum; and
- the Woodlawn and Gunning wind farms were shut down from 10 MW and 53 MW.

There were 27 New South Wales 5-minute prices above $250/MWh between 3 pm and 5.30 pm and around $90 000 of negative settlement residues across the New South Wales to Victoria interconnector accrued over the period. This is only one recent example. There are many examples where the impacts were far more significant outlined in Table 1.

11 September 2012 – counter price flows into New South Wales

Snowy Hydro can engage in similar bidding behaviour at its Murray power station in Victoria that results in counter-price flow into New South Wales. Snowy Hydro engaged in such behaviour on 11 September 2012, when the spot price in Victoria exceeded $2000/MWh for the trading intervals ending 9 am and 9.30 am. The spot price in South Australia exceeded $1400/MWh for the same trading intervals.

At 8.05 am as a result of a scheduled outage of the Lower Tumut to Wagga line (just inside the New South Wales region) a group of constraints were invoked. At 8.20 am, as the line was taken out of service, the constraint to manage flows on the Murray to Dederang lines (towards Melbourne) bound. Given its proximity to the Murray-Dederang line, the Murray generator has the greatest direct impact on flows on the line, reflected in its +1 coefficient. This means that reduced output from Murray assists managing the constraint on a one-for-one basis. The VIC to NSW interconnector has a coefficient of minus 1. This means that flows from Victoria towards New South Wales also assists with managing the constraint on a one-for-one basis.

At 8.43 am, Snowy Hydro rebid the entirety of its offered capacity at Murray of 1437 MW from prices above $30/MWh to zero to take effect for the dispatch interval ending 8.50 am. One minute later, Snowy Hydro rebid the ramp down rate for the Murray generators, reducing it from 50MW/minute to 3MW/minute, to take effect from the 8.55 am dispatch interval. The reason provided for the rebid was to avoid Murray being constrained off.

At 8.49 am, effective from 9 am, AGL rebid 270 MW of capacity at Eildon and McKay from prices below $74/MWh to above $12 700/MWh. Following this rebid, the dispatch price in Victoria increased from $73/MWh at 8.55 am to $12 890/MWh at 9 am (the price in South Australia also increased from $72/MWh to $9602/MWh).

As a result of Snowy Hydro rebidding its capacity to a price of zero, Murray's dispatch was increased from 900 MW at 8.45 am to 1437 MW at 8.50 am.[16] The combination of Murray's increase in output and the constraint on the Murray to Dederang lines caused the flows from Victoria to New South Wales to increase significantly from 181 MW at 8.45 am to 724 MW at 8.50 am.

These flows were counter price on the Vic-NSW interconnector, which saw negative settlement residues of around $1.1 million accrued in one hour. At 9.10 am a constraint that was invoked by AEMO to 'clamp' the accrual of negative settlement residues was violated as Murray could not be ramped down quickly enough to cease the counter-price flows.

[16] Murray has a ramp up rate of 200 MW per minute, but at the same time had the minimum allowable ramp down rate of 3 MW per minute.

Counter-price flows between Victoria and New South Wales

These very recent events are examples of the disorderly bidding as a result of network congestion that, on 20 occasions since December 2009, has led to significant counter-priced flows between Victoria and New South Wales. Tables 1 and 2 list each event where disorderly bidding led to more than $150 000 in negative settlement residues into New South Wales and into Victoria respectively. The tables outline for each event the maximum counter price flow, the maximum price in the higher priced region and the negative settlement residues that accrued.

Table 1: Summary of high cost recent examples of counter price flow into New South Wales

Date	Maximum spot price	Maximum counter price flow (MW)	Negative settlement residue
9/02/2010	$7847	560	$1 150 342
10/02/2010	$1489	497	$717 410
21/04/2010	$2093	496	$1 143 255
22/04/2010	$9999	641	$17 490 818
21/06/2010	$1756	894	$258 606
22/10/2010	$2470	1108	$982 967
28/11/2010	$115	1417	$156 831
31/01/2011	$9597	174	$439 729
30/05/2011	$1814	1039	$1 032 369
31/05/2011	$166	908	$225 632
2/07/2012	$4364	126	$172 325
11/09/2012	$2221	769	$1 324 546
Total			**$25 094 829**

Table 2: Summary of high cost recent examples of counter price flow into Victoria[17]

Date	Maximum spot price	Maximum counter price flow (MW)	Negative settlement residue
7/12/2009	$7715	37	$230 066
22/01/2010	$4514	205	$214 457
4/02/2010	$5541	1365	$5 025 392
11/02/2010	$1998	152	$173 259
26/03/2010	$1836	226	$205 485
13/04/2010	$3081	529	$804 754
29/06/2010	$4987	194	$471 903
9/11/2011	$6498	685	$1 733 523
Total			**$8 858 839**

[17] The 16 October 2012 event is not included as negative settlement residues were less than $150 000.

As is discussed later, the negative settlement residues are only one aspect of the inefficiencies that arise from disorderly bidding. There are larger impacts in terms of non-economic dispatch and through increasing the risk profile of all NEM participants, both customers and generators.

Congestion in Queensland around Gladstone – counter price flows into NSW

Congestion associated with the transmission lines between Calvale-Wurdong and Calvale-Stanwell has seen highly volatile prices in Queensland and significant negative settlement residues during 2011 and 2012. These outcomes have occurred during both high demand and moderate demand periods in Queensland. The AER considers that step changes in the dynamic line ratings for the relevant lines, significant disorderly bidding and the inclusion of the Queensland to New South Wales (QNI) interconnector with a small coefficient in the relevant constraint equations are key contributing factors.

The constraints at the centre of the issue are:

- Q>>NIL_855_871, which is designed to prevent the Calvale-Wurdong line from overloading should the Calvale-Stanwell line trip/fail; and
- Q>>NIL_871_855, which is designed to prevent the Calvale-Stanwell line from overloading should the Calvale-Wurdong line trip/fail.

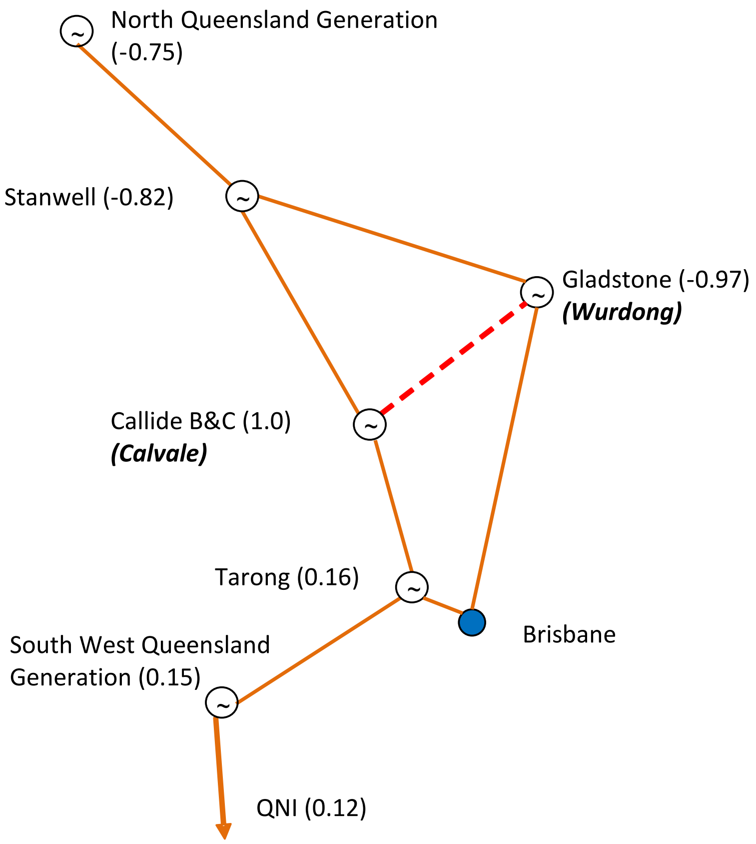
The constraint to manage the Calvale-Wurdong line binds more frequently than for the Calvale-Stanwell line, so this analysis will concentrate on the former. (Although the impacts of the two constraints are very similar). Figure 2 is a simplified representation of the transmission network around Gladstone in Queensland. The Calvale-Wurdong line is represented by the red dashed line. There are four key generators situated close to the Calvale-Wurdong and Calvale-Stanwell lines: Callide B, Callide C, Gladstone and Stanwell.

The majority of Queensland generators and flows on the QNI interconnector can influence the flows on the Calvale-Wurdong line. Included in Figure 2 are the relevant coefficients for generation stations and the QNI interconnector according to the Q>>NIL_855_871 constraint.

As the closest generators, Callide and Gladstone have the largest coefficients, followed by Stanwell. In general, power flows in a northerly direction from Callide towards Gladstone. The direction of the power flow means that if flows on the line have reached the limit it is necessary to increase or ‘constrain-on’ the Gladstone generators (with a -0.97 coefficient) and the Stanwell generators (-0.82 coefficient) and reduce or ‘constrain-off’ the Callide generators (1.0 coefficient). However, the amount and rate at which a generator is constrained on or off is limited by the offered availability and ramp rate of those generators.

The generators located in northern Queensland have the next highest coefficients. The majority of these generators are small capacity, fast-start peaking plant. The larger generators in south-west Queensland and QNI have lower coefficients due to their distance from the constraint. If the maximum constraining on or off of the Callide, Gladstone and Stanwell generators is reached (for example, due to low generator ramp rates), then other generators and the interconnector will need to be constrained on or constrained off. However, the smaller coefficients associated with these other generators and the interconnector means that there needs to be a larger change to dispatch to manage flows to the same degree.

Figure 2: Simplified transmission network around Gladstone



Background on dynamic transmission line ratings and Queensland generation ownership

In July 2011 the Queensland government restructured ownership and operation of its generating assets. In this restructure, Gladstone Power Station was transferred from Stanwell to CS Energy. CS Energy also owned Callide B and half of Callide C. The Tarong Power Stations (near Brisbane) were transferred to Stanwell Corporation.[18]

In 2011, Powerlink, the Queensland TNSP, implemented “dynamic” ratings on the Calvale-Wurdong and Calvale-Stanwell lines. This means that local weather conditions are used to determine the rating of the line. The introduction of dynamic ratings is usually beneficial for congestion as the maximum dynamic ratings for a line are often higher than the static rating (which assumes worst case weather conditions). In the case of the Calvale-Wurdong and Calvale-Stanwell lines, the introduction of dynamic ratings has generally increased the rating from around 800 MVA to in excess of 900 MVA. However, dynamic ratings of lines can fluctuate according to weather conditions, including wind speed and direction.[19] Step reductions in ratings as a result of a change in wind speed for example can cause the relevant constraints to bind at short notice.

[18] An earlier version of this report incorrectly stated that Wivenhoe was transferred to Stanwell Corporation. Wivenhoe was transferred to CS Energy.

[19] The thermal rating of a transmission line is influenced by weather conditions because airflow across a conductor can cool it and allow a higher power flow. Therefore ambient temperature, wind speed and wind direction (air flow across the conductor provides more cooling than along the conductor) can alter the maximum safe power flow.

Binding Calvale constraints, disorderly bidding and counter-price flows

Since July 2011 there were 24 occasions when the constraints used to manage overloading of the Calvale-Wurdong (and/or Calvale-Stanwell lines) have bound and led to significant counter-price flows into New South Wales. Congestion on these lines has been triggered on each occasion by a combination of changes in the dynamic ratings of the line and/or rebidding of the Gladstone or Callide stations by CS Energy.

As a result of the restructure of generation in Queensland, CS Energy operates the power stations which are located on either end of the Calvale-Wurdong line (Gladstone and Callide power stations). CS Energy can contribute to causing the constraint to bind by increasing the northerly flow on the line. It can do this by increasing output at Callide, reducing output at Gladstone (which also results in more northerly flow across the line) or both. A generator can change its likely dispatch level by changing the offer price, so CS Energy can increase the flow on the Calvale-Wurdong line by rebidding capacity at Callide into lower prices or by rebidding Gladstone into high prices. If the change in offer price is accompanied with a high ramp rate then the change in dispatch level can be quite rapid. This can then cause the constraint to bind, leading to the constraining on or constraining off of generators and QNI.

As noted earlier, if the constraint binds economic dispatch is interrupted. NEMDE attempts to avoid the constraint violating by constraining on and off generators, however, NEMDE still finds the lowest cost way of dispatching generation based on the generator bids. This means that if the offer prices of Gladstone increase significantly then NEMDE will dispatch other generators in preference even though Gladstone has a large coefficient (i.e. it doesn't need to shift output very much to relieve the constraint). This means the outputs from generators or flows over QNI are changed by a large amount.

It was also noted earlier that the ability for the constraint to be managed by changing the dispatch of a generator depends on the ramp rate offered for that generator. At times CS Energy has been rebidding to reduce Callide's ramp down rates so that when the constraint binds Callide can only be decreased at a slow rate (3 MW/min). After Gladstone, the next highest coefficient generators are then dispatched at their ramp rates. The next highest coefficients are for Stanwell Power Station, which is generally 'ramped up' (at 60 MW per 5 minutes), and the smaller northern generators (which are generally constrained-on, requiring the generators to start up, but often rebid as unavailable to avoid uneconomic dispatch).

This is not, however, sufficient to satisfy the constraint. Therefore low priced generation in south west Queensland is also reduced. Southerly flows across QNI into New South Wales also assist in managing the loading on the line. However, the lower coefficients for the south west Queensland generators and QNI mean that the magnitude of the southerly changes are very large – for example QNI must be changed by 8 MW (1/0.12) for every 1 MW that Callide does not change.

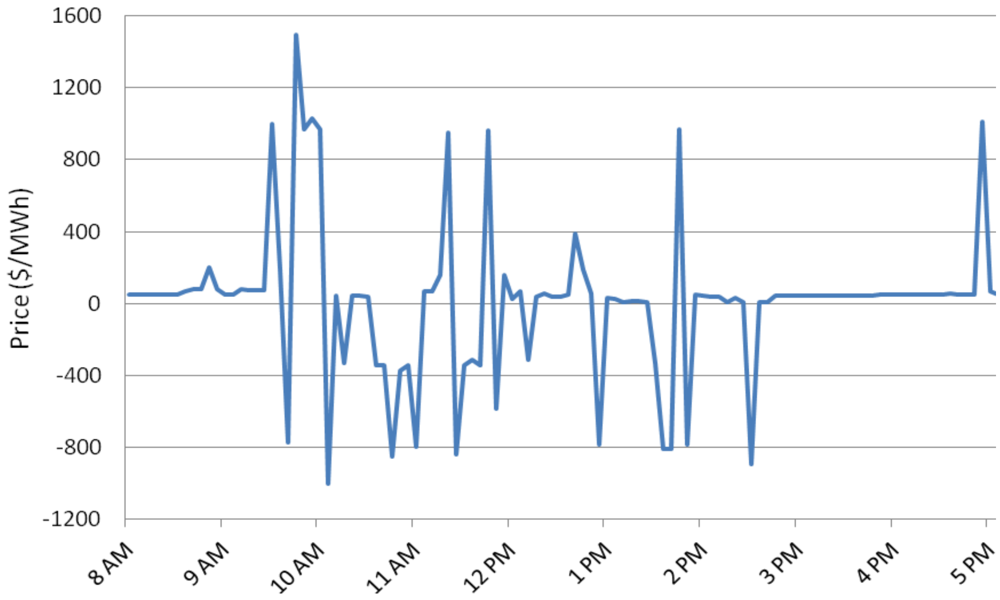
The reduction in the dispatch of low priced south west Queensland generation and dispatch of high priced capacity at Gladstone leads to a high Queensland spot price. Flows on QNI change, with flows being forced south (counter-price), and negative settlement residues accrue. These high price outcomes often occur for only one or two dispatch intervals until Stanwell's (lower-priced) generation ramps up sufficiently to be dispatched, relieving the constraint.

Price volatility in Queensland

The bidding behaviour of participants in response to the binding constraints has contributed to a significant amount of price volatility in Queensland. For example between January and March this year, Queensland spot prices exceeded $100/MWh 72 times (with two prices above $2000/MWh), and sixteen negative spot prices (including three below -$100/MWh) followed these high prices.

As illustrated by the events of 25 August, the dispatch prices can fluctuate from very high prices to the price floor. In Figure 3 it can be seen that between 9 am and 2.30 pm (and for a further dispatch interval at 4.55 pm), Queensland 5-minute prices were extremely volatile, fluctuating between $1493/MWh and -$1000/MWh. The 5-minute price exceeded $900/MWh on nine occasions and fell below -$300/MWh on 21 occasions.

Figure 3: Five-minute Queensland prices on 25 August 2012



Such volatility can lead to market uncertainty and cause inefficient dispatch of generation. It also makes it more difficult and expensive for retailers and generators to hedge against volatility. These market conditions can deter new retail entry and new generation investment.

Constraint formulation

Fully co-optimised constraints have been used for all constraint formulations since mid 2004 (as detailed in Appendix A). The outcomes discussed above, including the accrual of negative settlement residues, are symptomatic of the use of fully co-optimised constraints under certain conditions. One of the factors AEMO took into consideration in specifying the smallest coefficient on a fully optimised constraint at 0.07 was to prevent significant swings for the relevant input. Nevertheless there have been large step changes in flows over the QNI interconnector as a result of disorderly bidding associated with congestion around the Gladstone region. In its May 2012 report on congestion issues in Queensland, AEMO acknowledged an alternative to the current arrangements would be for interconnectors to have a different threshold than other variables.[20] AEMO considered that in doing so, the relevant constraint equation would require a larger operating margin – i.e. would have to bind

[20]See http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Market-Event-Reports/NEM-Operations-Review-Queensland-Summer-2012-855-871-Congestion

at a lower level – to ensure that system security was maintained. Fully co-optimised constraints are discussed in more detail in Appendix A.

Recent accrual of negative settlement residues

Table 3 lists each event where congestion in the Gladstone region and disorderly bidding led to more than $150 000 in negative settlement residues into New South Wales. The table outlines for each event the maximum counter price flow, the maximum price in the higher priced region and the negative settlement residues that accrued.

Table 3: Significant counter price flows related to congestion around Gladstone

Date	Maximum spot price	Maximum counter price flow (MW)	Negative settlement residue
5/09/2011	$2117	569	$371 303
12/01/2012	$1757	917	$992 763
15/01/2012	$228	1148	$183 147
27/01/2012	$509	966	$302 697
29/01/2012	$2080	1257	$1 271 630
14/02/2012	$360	876	$221 795
20/02/2012	$503	667	$184 699
21/02/2012	$392	1004	$195 922
22/02/2012	$438	772	$255 562
2/03/2012	$317	872	$307 724
3/03/2012	$265	854	$271 734
4/03/2012	$339	491	$165 025
5/03/2012	$289	1155	$247 736
6/03/2012	$268	898	$201 920
9/03/2012	$260	1079	$278 325
10/03/2012	$196	1118	$233 506
23/03/2012	$396	969	$297 466
25/08/2012	$646	785	$346 152
30/08/2012	$463	900	$178 514
31/08/2012	$311	1147	$301 895
1/09/2012	$603	1078	$293 140
3/09/2012	$370	1112	$511 862
8/09/2012	$408	978	$245 893
27/10/2012	$1085	1034	$433 501
Total			**$8 293 909**

As was noted earlier, negative settlement residues are only one aspect of the inefficiencies that arise from disorderly bidding.

Interconnector flows and SRAs

Interconnection of the regions of the NEM via the transmission network allows regions with tight supply/demand balances to import low priced electricity, reducing the need to dispatch high priced capacity within the region. This interconnection benefits customers/retailers through lower wholesale energy costs and enables generators with spare capacity to generate more electricity than they otherwise would, leading to the more efficient use of generation assets and a reduction in the ability of local generators to exercise market power. The effective operation of interconnectors plays a significant role in facilitating interregional trade and competition, to the benefit of market participants and end users of electricity.

As illustrated by the *Congestion in Queensland around Gladstone* section of this report, physical or security limitations of interconnectors are not the only factors that influence the amount of energy that can flow over the interconnector. Constraint equations designed to manage flows over other parts of the transmission network utilise interconnector flows as a variable input. As demonstrated by the events in Queensland, flows over an interconnector that is located a significant distance away from the relevant transmission line can be significantly impacted as a result of disorderly bidding and the constraint formulation.

Risk management and hedging

The reduction in flows over an interconnector as a result of disorderly bidding causes inefficient pricing and generation outcomes in affected regions. Counter-price flows impose significant costs on TNSPs. In addition, counter-price flows impact on the value of holding SRA units.[21] One of the reasons that market participants purchase SRA units is to facilitate inter-regional hedging. Inter-regional hedging facilitates competition between generators in different regions and is efficiency enhancing as customers/retailers can hedge for less cost. Inter-regional hedging occurs when a party enters into a hedge contract with a counterparty located in another region of the NEM. The terms of hedge contracts are usually struck with reference to the spot price of a specified region. The counterparty that is located in a different region of the NEM is exposed to the risk of price separation between the regions. Where significant divergence between the two spot prices occurs, one party bears the risk of the price difference. Purchasing a sufficient amount of SRA units to match the hedge contract quantity and capture the price difference between regions is one way to mitigate that risk.

When the flows over an interconnector from a low priced region into a high priced region are constrained due to disorderly bidding, the amount of inter-regional settlement residues that accrue (the price difference multiplied by the energy that flowed) is reduced. As settlement residues are divided equally amongst SRA unit holders, this means that unit holders receive a lower than expected return for the price difference between the two regions for the relevant trading intervals. When counter-price flows occur, the value to SRA unit holders is zero.[22]

SRA units for interconnector flows during a specified quarter are auctioned in advance. The number of units sold for an interconnector direction is set with reference to the nominal capability of the interconnector. The price which bidders are prepared to pay is informed by an assessment of the

[21] Inter-regional settlement residues are allocated to holders of SRA units on a pro rata basis. If a participant has purchased 100 MW of SRAs out of a possible 1200 then it would receive one-twelfth of the inter-regional settlement residues that accrue on that interconnector for every trading interval (provided the residue is positive). SRAs are sold for each quarter of the year.

[22] If counter-price flows occur, then negative inter-regional settlement residues will accrue. Under rule changes which commenced in July 2010, the TNSP in the importing region is responsible for funding negative inter-regional settlement residues.

potential price divergence between two adjacent regions during the relevant quarter and an assessment of the level of average flows over the interconnector during periods of high prices.

The variability of average flows over interconnectors during periods of high price divergence between regions since 2009 is demonstrated by Table 4. The table shows for each of the 2009-10 to 2011-12 financial years (and the first four months of 2012-13) the number of trading intervals when spot prices in one region are at least $100/MWh higher than the neighbouring region and, of those intervals, the number when the interconnector flowed counter-price. The table also shows average inter-regional flows during these high priced periods. It also shows for comparison the quantity of settlement residue units available for purchase in the settlement residue auction. If the average flow is negative then, on average, flows have been counter-price. In these cases the value of the SRA units will be low.

Table 4: Imports across the major interconnectors during high price periods since 2009

Relative regional spot prices	Number of trading intervals (number of counter price flow intervals)				Average flow (MW)				Available SRA units
	2009-10	2010-11	2011-12	2012-13 YTD	2009-10	2010-11	2011-12	2012-13 YTD	
$Qld_{\$}$>$NSW_{\$}$	41 (9)	19 (19)	60 (48)	17 (17)	27	-255	-255	-415	550
$NSW_{\$}$>$Qld_{\$}$	131 (24)	63 (2)	5 (0)	20 (0)	193	459	299	444	1200
$NSW_{\$}$>$Vic_{\$}$	172 (23)	108 (3)	6 (2)	5 (4)	221	396	96	-92	1500
$Vic_{\$}$>$NSW_{\$}$	69 (27)	9 (9)	1 (0)	6 (4)	59	-260	52	-67	1300
$SA_{\$}$>$Vic_{\$}$	110 (1)	34 (0)	27 (2)	9(1)	179	207	176	112	700

The table analyses interconnector metered flows for trading intervals where neighbouring region prices differ by more than $100/MWh. Figures for 2012/13 current as at 14 November 2012.

SRA firmness

Disorderly bidding during high price events has had a significant impact on New South Wales to Queensland flows and flows between Victoria and New South Wales. This is demonstrated by Table 4 which shows that when prices in Queensland were higher than prices in New South Wales (19+60+17 or 96 trading intervals), interconnector flows have been predominantly counter-price since 2010-11 (19+48+17 or 84 trading intervals), reflected in a negative average flow (255, 255 and 415 MW south, which is counter price). The majority of these counter-price flows have occurred during times of congestion around Gladstone in central Queensland. This means that the utility of SRAs to manage high Queensland prices is severely diminished. The negative settlement residues that accrued during high priced periods associated with central Queensland congestion are detailed in Table 3.

In contrast, during the same period when New South Wales prices were high there were rarely counter-price flows from Queensland, with positive average interconnector flows (however, still well below the 1200 MW of SRA units sold). However, there were lower average flows from Queensland into New South Wales during 2009/10 due to significant counter-priced flows (24 out of 131 high priced trading intervals). These counter-price flows related to disorderly bidding associated with congestion caused by TransGrid's large scale upgrade of the transmission network west of Sydney.[23]

[23] The AER published a number of $5000 reports covering these events, including the 7 December 2009 event when rebidding by Snowy into low prices at Tumut and Upper Tumut led to counter-price flows into Victoria.

Disorderly bidding by Snowy Hydro has at times led to counter-price flows both northwards and southwards between Victoria and New South Wales, although to a lesser extent than for the New South Wales to Queensland interconnector. Table 4 shows that although there were few occasions when the price in Victoria was higher than New South Wales (69+9+1+6 or 85 trading intervals) a high proportion of the time flows were counter price (9 out of 9 in 2010-11 and 4 out of 6 so far this financial year).

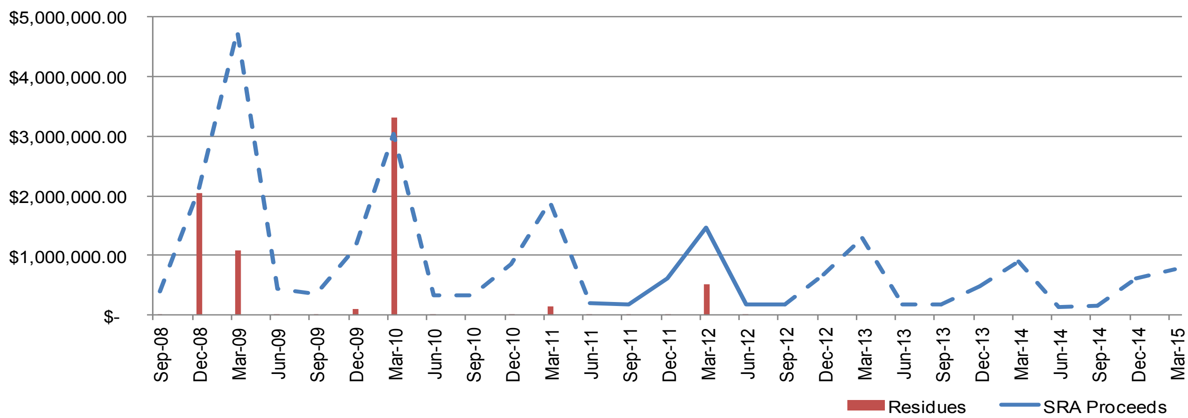
The effect of disorderly bidding on interconnector flows and settlement residues is difficult to predict. As a consequence of the uncertainty, the price that market participants are willing to pay for SRA units can be affected.

The AER considers that the recent significant reduction in utility of settlement residues as a result of 'disorderly bidding' has seen a noticeable reduction in the SRA proceeds, reflecting the reduced market valuation of this mechanism. This is evident from Figure 4, which shows quarterly auction proceeds as a blue line for New South Wales to Queensland settlement residues and, with estimated proceeds for future quarters (based on tranches already sold) as a dashed blue line. A possible indicator of the auction value is the historical quarterly settlement residues, which are shown as red columns.

It is possible that expectations of lower demand and low prices have influenced future SRA proceeds. However, as noted earlier, the value of inter-regional settlement residues is determined by the price difference and the interconnector flows. The AER believes the potential for extreme price differences in the summer periods going forward is not likely to diminish materially, as this is driven by infrequent extreme demand (as a result of high temperatures in south east Queensland or tight supply conditions). Therefore the AER considers that the reduced market valuation is primarily caused by an expectation of reduced interconnector flows and counter-price flows during price differential events.

Figure 4 shows that for New South Wales to Queensland flows the SRA proceeds have fallen and are projected to continue to fall – consistent with the increasing prevalence of counter-price flows.

Figure 4: New South Wales to Queensland quarterly SRA proceeds and residues



It should be noted that New South Wales to Queensland flows have had the most significant decline in SRA proceeds. However, the forecast proceeds for the interconnectors between Victoria and New South Wales are also declining for both directions; the AER considers that disorderly bidding by Snowy Hydro is a contributing factor.

Summary of impacts

The AER has observed an increased prevalence of disorderly bidding associated with network congestion in the last three years. Disorderly bidding has a detrimental impact on the efficient operation of the NEM through increased price volatility, inefficient dispatch and reduced inter-regional trade. While it is extremely difficult to quantify the impacts of disorderly bidding, the AER does consider that the costs of disorderly bidding, such as counter-price flows, have risen with the increase in frequency. The AER considers that a number of factors have contributed to disorderly bidding including constraint formulation, generation ownership changes, the abolition of the Snowy region as well as network issues.

The NEM, being an energy only market, relies on efficient price signals to encourage and reward investment in generation. Interconnectors provide an important facilitator in the NEM by allowing excess low cost generation in a neighbouring region to supply into a region where tighter supply conditions result in high spot prices. Customers pay for the shared transmission network as they benefit from improved efficiency in dispatch of low cost generation. Generators are not, however, obligated to offer to the market at cost. NEMDE considers generator offers as a proxy for cost, which means that negative offers that arise through disorderly bidding and are not reflective of generator costs are dispatched, which can lead to inefficient dispatch and counter-price flows.

While the out of merit order dispatch is a significant cost inefficiency in and of itself, the AER also considers price volatility associated with disorderly bidding is an additional source of inefficiency. High prices driven by congestion can distort the price signals to trigger new investment in generation, as well as potentially reducing the return on existing generation assets. Price volatility also adds to the risk profile of retailers/customers, which increases costs through the supply chain. The extent to which to this price volatility can be managed through SRAs is also affected by disorderly bidding.

The AER considers that disorderly bidding has a detrimental impact on SRA firmness by reducing interconnector flows. In this regard, the effect of disorderly bidding can be two-fold in that the bidding has caused the high prices in the first instance while simultaneously reducing the protection of SRAs by reducing interconnector flows. That is, disorderly bidding has created the risk that SRAs are designed to manage, whilst simultaneously reducing the value of that risk management tool. The AER considers that the reduction of firmness of SRA units imposes potential long term costs on market participants and end users. Inter-regional hedging can play a significant role in ensuring that there is a competitive tension between generators. The effectiveness of inter-regional hedging is, however, dependent on the firmness of SRA units in mitigating the risk of price separation between regions.

In addition, end users may have to pay higher network tariffs than what they otherwise would have absent the conduct. TNSPs receive the proceeds from SRA auctions, which go to offset the TUOS fees TNSPs charge end users. When negative settlement residues accrue, the TNSP in the importing region is required to fund the shortfall, which is sourced from end users. Where disorderly bidding affects the value of SRA units, TNSPs receive lower proceeds from SRA auctions. Accordingly, disorderly bidding reduces the extent to which SRA proceeds offset TUOS fees.

Conclusion

Over the last three years in particular the increasing prevalence of disorderly bidding has created unnecessary price volatility, led to inefficient dispatch and created counter price flows across interconnectors. As a result the ability for market participants to manage risk across interconnectors has reduced and with it competition between regions. This has been most prevalent between Queensland, New South Wales and Victoria. The market design incentivises disorderly bidding by generators when faced with being constrained. Network constraints can occur anywhere in the NEM and accordingly any interconnector, not just QNI and VIC-NSW, is at risk of counter price flows precipitated by disorderly bidding.

The AEMC’s *Transmission Frameworks Review* has recommended changes to the settlement of generators that are located at mispriced connection points and engage in disorderly bidding through its Optional Firm Access (OFA) proposal. The AER welcomes the AEMC's work to develop the OFA proposal. It aims to address a range of important issues, including increasing the firmness of interconnector availability, in order to improve energy contract liquidity and competition. While the AEMC has made significant progress, there are many important areas of detail that are yet to be developed. The success of the model will, in part, lie in the detail.

As the AEMC is tackling a range of very complex issues, it is likely that any reforms will take a long time to implement. Therefore, the AER considers that, given the significant and pressing issues associated with disorderly bidding and counter-price interconnector flows, fast-tracked changes should be implemented in the short term to at least partially address the problem. One option would be to introduce a simplified congestion management mechanism via relatively straightforward changes to AEMO’s settlement systems. This could, in effect, be a stepping stone towards the full OFA model. A congestion management mechanism would deliver significant gains. In particular, it could address much of the disorderly bidding problem, which would have flow on effects in terms of improving interconnector flows and the firmness of inter-regional hedges. Alternatives may include a greater restriction on generators lowering their ramp rates. At the moment, generators must specify a ramp rate that is 3MW/minute or higher unless there is technical limitation on their plant. For large generators this is a very low ramp rate. For example, Snowy Hydro’s Tumut facility is treated as a single unit by NEMDE and has a capacity of 1800 MW. If it is operating at its maximum capacity of 1800 MW, (which it can reach from zero in less than 10 minutes with its ramp up rate of 200 MW/min) and bids in a 3MW/minute ramp down rate, it will take 10 hours to ramp down to zero output. Changing the rules so that generators must specify a ramp-rate of at least a certain percentage (say 3 per cent) of their capacity would significantly lower the inefficiencies caused by disorderly bidding. There may be alternatives, such as restrictions on bidding into negative prices during times of congestion, which could also assist.

The AER also recommends that AEMO commence reviewing the constraint formulation guidelines to assess whether a minimum threshold should be applied to determine if interconnectors are co-optimised. This could prevent rapid changes in interconnector dispatch outcomes that result from network congestion that is remote from the interconnector. Such a change would assist somewhat in addressing the Queensland to New South Wales flow issues discussed in this report. However, it would not solve counter price flows between Victoria and New South Wales that occur as a result of disorderly bidding by Snowy Hydro, as the VIC-NSW interconnector has a high coefficient. (In other words, because the VIC-NSW interconnector will always have a high coefficient, changing the minimum threshold will not alter the constraint equation).

A Background on the full co-optimisation of network constraints

In late 2000, the commissioning of the Queensland to New South Wales interconnector (QNI) created the first situation where management of joint inter-regional and intra-regional network flows had the potential to become a significant issue.

To pursue a solution a Network Constraints Reference Group was established in April 2001. This group published an options paper in January 2002 indicating that the then National Electricity Market Management Company (NEMMCO), now the AEMO, preferred an Option 4 formulation where both inter-regional and intra-regional flows were co-optimised according to the generator offers.

Following further consultation and the granting of a derogation under the then National Electricity Code (now the National Electricity Rules), from July 2004, NEMMCO began to adopt the fully co-optimised constraint formulation for all constraint equations. In this formulation, all terms (both generators and interconnectors) are placed on the left hand side of the constraint equation and therefore may be directly controlled by the NEMDE. Having direct control of as many of the variables in the dispatch process as possible allows AEMO to achieve a more optimal dispatch of all possible control variables and thereby improves AEMO's ability to manage system security, with flow on benefits of reduced safety margins in network constraint equations.

In May 2005, the Ministerial Council on Energy (MCE) endorsed NEMMCO's formal adoption of the fully co-optimised constraint formulation. Formalising the requirement that NEMMCO use the fully co-optimised constraint formulation was also endorsed by most market participants as part of the consultation process for the AEMC's Congestion Management Review (CMR). The CMR Final Report (published in June 2008) recommended that the constraint formulation be formalised in Chapter 3 of the Rules. The Rule commenced on 1 September 2009.

A risk with fully optimised constraints is that they can lead to counter-priced flows and therefore inter-regional settlement deficits if remote intra-regional generation is offered at a lower price than a neighbouring region. This can occur when generators are constrained and rebid to the price floor – which has come to be known as disorderly bidding. This in turn leads to AEMO to intervene to manage excessive accumulation of negative residues by clamping interconnectors. At times this is ineffective (with counter-price flows continuing to occur) as power system security (the management of network elements and generator technical parameters such as ramp rates) takes precedence over the management of counter-price flows. Even when clamping is successful, however, and counter-price flows are reduced to zero, there are zero imports into the high priced region, which means that the return to SRA unit holders is zero.