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21 August 2013

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

Request for Rule Change – Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities

As you are aware, the AER has been very active in the debate surrounding the implications of congestion-related disorderly bidding. Indeed, the AER made several submissions to the Australian Energy Market Commission's (AEMC) Transmission Frameworks Review (TFR). In addition, in December 2012 the AER published a Special Report entitled *The impact of congestion on bidding and inter-regional trade in the NEM* ([attached](#)) and in March 2013 the AER made a submission to the Productivity Commission's *Electricity Network Regulatory Frameworks Review* entitled *Possible options for interim solutions to congestion-related disorderly bidding* ([attached](#)).

Disorderly bidding is bidding by generators in a non-cost reflective manner, typically in response to transmission congestion. For example, if the market price is high, but congestion means certain generators have to generate less, those generators have an incentive to find ways to keep generating. They might bid in at prices well below their costs or restrict the speed at which the output of their plant can be lowered.

Over the last three years in particular the increasing prevalence of disorderly bidding has led to inefficient dispatch and created unnecessary price volatility which is impossible to predict. This unnecessarily increases the wholesale spot market price risk faced by retailers and generators. The 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 more difficult for retailers and generators to hedge across region

boundaries. This lowers the competitiveness of the wholesale market with longer-term flow-on effects to efficiency and prices.

In addition, there is a clear productive efficiency loss from disorderly bidding through high-cost generation being dispatched in place of low-cost generation. This loss is most obvious in situations where disorderly bidding leads to counter-price flows on interconnectors (i.e. electricity flows from a high-price region into a low-price region), and consumers in the low-price region have to fund the shortfall.

The TFR Final Report recommended the Optional Firm Access (OFA) Model as a longer term solution to managing congestion in the National Electricity Market (NEM). The AER is supportive of further consideration of this approach. However, it is widely acknowledged that implementing the OFA Model represents a significant body of work and would take several years to implement. Given the seriousness of the disorderly bidding problem and the high costs for consumers, we consider an interim “partial fix” is required earlier.

We are proposing a rule change which would require generators to submit ramp rates (at all times) that reflect the maximum the generator is safely capable of achieving. This rule change proposal would apply equally to scheduled and semi scheduled generators, scheduled network services and scheduled loads.

As a related matter, this rule change proposal also seeks to ensure that when a fast start inflexibility profile (FSIP) is submitted, it is reflective of actual plant limitations at the time.

We consider that the rule change will ensure that there is alignment between the treatment of ramp rates/FSIP, and the treatment of frequency control ancillary services parameters and inflexible declarations. The current rules are clear that frequency control ancillary service parameters must reflect the technical parameters of the plant and that generators can only declare their plant inflexible based on technical limitations. Our rule change seeks to make the rules consistent with respect to the remaining technical parameters of a bid.

At times, generators have used ramp rates and FSIPs to achieve commercial outcomes. In particular, if a generator is required to be constrained off by the Australian Energy Market Operator (AEMO) due to network constraints during a period of high prices, the generator is incentivised to bid its ramp rate down to very low levels to minimise the extent to which it is constrained off. This leads to inefficiencies in dispatch and fluctuations in price. This Rule change proposal will demonstrate that the use of ramp rates to achieve commercial outcomes is not transient behaviour, but commonplace. Requiring generators to bid in their maximum safe ramp rate will significantly address the issue.

We consider that the rule change will also improve the security of the NEM when there is network congestion, as AEMO will be able to move the output of generators at a faster rate to address network constraints. AEMO will not breach a generator’s technical parameters (which includes ramp rates and FSIPs) as it does not have any other information about a plant’s capability. Indeed, AEMO may violate some network constraints before it breaches a plant’s technical parameters. Therefore, having technical parameters that are the maximum a generator can safely attain will assist AEMO to maintain security.

It is important to note that the AER is supportive of market participants achieving their commercial objectives. However, the use of technical parameters to achieve commercial

objectives can be harmful both in terms of inefficient market outcomes and the ability for AEMO to manage system security in an optimal fashion. To this end, this rule change proposal seeks to clarify the distinction between the technical and commercial parameters of bids.

Requiring participants to submit a ramp rate at all times that reflects their maximum safe capability is an extension of the AEMC's 2009 rule change (in response to a rule change proposal by the AER) which saw the minimum ramp rate increase from 1 MW/min to 3 MW/min or the technical maximum if that is less. Given the concerns with network congestion and associated disorderly bidding, the AER considers it appropriate to make ramp rates a technical parameter at all times.

We appreciate that given the very technical nature of ramp ramps, concerns may be raised with respect to how such a change may be enforced. To this end, the rule change proposal recommends that the AER revise its *Rebidding and Technical Parameters Guideline*, through the formal consultation process, outlining how such a requirement would operate in practice. This is discussed in more detail in the body of this rule change proposal.

Should you have any queries in relation to this matter, please don't hesitate to contact Tom Leuner, General Manager, Wholesale Markets, on 03 9290 1890.

Yours sincerely



Andrew Reeves
Chair

National Electricity Rules

Proposal to change clause 3.8.3A (Ramp rate) and clause 3.8.19 (Dispatch inflexibilities).

A Name and address of person making the request

Australian Energy Regulator
Level 35
360 Elizabeth St
MELBOURNE VIC 3000

B Description of proposed rule

This proposal relates to clauses 3.8.3A (Ramp rates) and 3.8.19 (Dispatch inflexibilities) of the National Electricity Rules (rules).

The AER considers that incentives for disorderly bidding are a significant problem with the current NEM design. This Rule change proposal proposes a partial solution to mitigate the most egregious cases of disorderly bidding. The AER considers this can be achieved by requiring scheduled network services, scheduled loads and scheduled and semi-scheduled generating units to provide a technical ramp rate at all times. Essentially this means requiring the relevant participant to submit a ramp rate that is the maximum the plant can safely attain at the time. This would put beyond doubt the status of ramp rates as technical parameters of a bid.

The AER also considers that in some circumstances fast start generators can use their dispatch inflexibility profile (more commonly referred to as fast start inflexibility profile or FSIP) to achieve commercial outcomes. Although not explicitly stated in the rules, as with ramp rates, a fast start unit's FSIP is considered to be a technical parameter of a bid and therefore not to be used for commercial purposes. To ensure the rules reflect this, this rule change proposal seeks to make it a requirement that fast start generators submitting an FSIP must ensure that the FSIP reflects the technical limitations of their plant at the time.

As previously mentioned, the AER considers ramp rates and FSIPs to be technical characteristics of a bid; therefore it is appropriate to address the perceived anomalies in the rules in relation to both as one rule change proposal package.

Ramp rates

Clause 3.8.3A relates to ramp rates, the rate at which the output of a generating unit may be varied up or down. The clause provides that participants must provide an up ramp rate and a down ramp rate to AEMO that is at most the relevant maximum ramp rate provided in accordance with clause 3.13.3(b)¹ and at least:

- 3MW/min in the case of a scheduled network service or scheduled load, or

¹ Clause 3.13.3(b) is a civil penalty provision and provides that "All *Scheduled Generators, Semi-Scheduled Generators* and *Market Participants* must provide AEMO with the *bid and offer validation data* relevant to their *scheduled loads, scheduled network services* and *generating units* in accordance with schedule 3.1".

- the lower of 3MW/min or 3 per cent of the unit's maximum generation in the case of a scheduled or semi-scheduled generating unit,

unless there is a technical limitation preventing this.

This rule change proposal seeks to require relevant participants to submit a ramp rate that reflects the maximum safe capability at all times. The focus of the ramp rate component of this rule change proposal is on the bidding and rebidding of ramp rates by generators. However, for the sake of consistency, the rule changes are proposed to cover all participants to whom obligations regarding ramp rates apply.

The proposed revised drafting of clause 3.8.3A is contained in Appendix D.

Dispatch inflexibility profile

A slow start generator is defined in the rules as being a generator that is unable to synchronise and reach minimum loading within 30 minutes. In contrast, those generators that can satisfy these requirements, by default, are referred to as fast start plant. The rules provide a mechanism for fast start plant to inform the dispatch process of minimum start and stop times, and of capacity inflexibilities. This mechanism is known as the FSIP and is contained in Clause 3.8.19(e) of the rules.

This rule change proposal seeks to make it a requirement that those generators submitting an FSIP must ensure that the FSIP reflects the technical limitations of their plant at the time.

The proposed revised drafting of clause 3.8.19 is contained in Appendix D.

C Statement of Issues

Background

On 21 April 2008, the AER submitted a rule change proposal relating to the ability of relevant scheduled generators and market participants to bid and rebid technical parameters, including ramp rates, market ancillary service offers, and dispatch inflexibility profiles, in pursuit of commercial objectives when power system security could be compromised.

The proposal was precipitated by an AER investigation into the events of 31 October 2005. On that day, the National Electricity Market Management Company (NEMMCO), now AEMO, invoked network constraints to manage the impact of a transmission outage, which had the effect of constraining the dispatch of some generation in the vicinity. The AER found that some generators took action to minimise the commercial impact of these constraints by rebidding their ramp rates to very low levels. This limited the rate that NEMMCO was able to reduce the dispatch levels of those generators, thus hindering NEMMCO's ability to effectively manage power system security during that event.

In 2009, the AEMC made a rule (*Ramp Rates, Market Ancillary Services Offers, and Dispatch Inflexibilities*, No.1 2009) which in effect separated the commercial parameters of an offer or bid (price and availability, which are both required to be rebid in "good faith") from the technical parameters (ramp rate, dispatch inflexibilities and frequency control ancillary services trapezia).

The resulting rule change moved towards aligning the way in which these parameters were treated in the dispatch arrangements. It made clear that generators can use the commercial parameters of a bid for commercial purposes (i.e. reaching their desired output), but the NEM dispatch engine (NEMDE) will override them if required (i.e. by backing off low priced plant out of merit order in response to congestion). On the other hand, the technical parameters (including ramp rates) are required to ensure the safe operation of plant can be maintained. In support of this, NEMDE will not breach technical parameters under almost any circumstances. The distinction between technical and commercial parameters of an offer or bid is discussed further under the section *Technical versus commercial parameters of a bid*.

Problems associated with disorderly bidding

The way network congestion is managed was examined in detail by the AEMC in the TFR. Scarce transmission capacity in a given region can limit the ability of some generators to sell their energy at the regional wholesale price. During times of congestion, generators have an incentive to offer their electricity in a non-cost reflective manner (so-called “disorderly bidding”), which may lead to the dispatch of higher priced generation.

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.

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. All regions have been impacted by disorderly bidding in the past.²

The AER considers that incentives for disorderly bidding are a significant problem with the current NEM design. While the AEMC’s TFR Final Report proposed solutions to manage network congestion, those solutions, if implemented, would take many years to come into effect. This Rule change proposal does not represent a holistic solution to manage network congestion. Instead, it proposes a partial, easier to implement solution to help mitigate the most egregious cases of congestion-related disorderly bidding.

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.

What is disorderly bidding?

Network constraint equations are used in NEMDE together with generator bids to determine the optimal economic dispatch of generators to meet customer demand, subject to ensuring the system is secure.³

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. Generators with a negative coefficient in the constraint equation 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. Generators with a positive coefficient in the constraint equation can rebid capacity into negative price bands to reduce the extent to which their dispatch levels will be decreased.⁴ As NEMDE seeks the optimal way to manage the constraint (based on generator offer prices as a proxy for cost), rebidding capacity in this way will influence NEMDE's outputs, including generator dispatch levels, interconnector flows and regional prices.

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 increase price volatility in a region. When a constraint binds, regional prices can increase rapidly as NEMDE dispatches higher cost generation at their ramp rates to satisfy the constraint. Disorderly bidding can then initially lead to spot prices significantly higher than forecast, with offers further up the supply curve dispatched because of low ramp rates for lower priced offers and some peaking generators having insufficient time to react to ensure they are dispatched. The price can then fall significantly once the constraint no longer binds or lower priced offers with lower ramp rates are able to be utilised.

Impacts of disorderly bidding on interconnector flows

Disorderly bidding can also cause counter-price flows on interconnectors. According to the NEM design, in the normal course of events electricity will flow from low priced regions across interconnectors into higher price regions. However, when electricity is exported from a high price region into a lower priced region in order to manage congestion, counter-price

³ A detailed explanation of how constraints operate is contained in the AER's *Special Report – The impact of congestion on bidding and inter-regional trade in the NEM* (attached), an excerpt of which appears in Appendix C of this document.

⁴ 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.

flows occur. Under these conditions, NEMDE determines that the optimal outcome to manage congestion in one region is to force the flow of electricity into an adjoining region. This outcome is exacerbated by the fact that interconnectors are effectively not limited by ramp rates, which allows for the flow of electricity over interconnectors to be changed very quickly.⁵

The most egregious examples of counter-price flows on an interconnector when the regional price differentials and flows are large are caused by disorderly bidding by generators close to an interconnector, when congestion arises between that generator and the regional reference node (RRN).

The AEMC is currently undertaking a review into the management of negative inter-regional settlements residues, and published an issues paper in April 2013.⁶ In its submission to the issues paper, AEMO stated that the vast majority of negative settlement residue events result from constrained generators bidding at the market floor price, causing a spill-over across interconnectors.⁷

Inter-regional settlement residues

Inter-regional settlement residues occur when the prices between regions separate. Generators in the exporting region are paid at their regional spot price while retailers in the importing region 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).

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. In turn, the TNSP recovers this expense through higher network service fees, which are paid by customers.⁸

Tables A1 and A2 in Appendix B detail 23 occasions where disorderly bidding at the time of network congestion has led to significant counter-price flows between Victoria and New South Wales since December 2009. Collectively these events led to almost \$35 million in negative settlement residues. Table A3 lists each event where congestion in the Gladstone region and disorderly bidding led to more than \$150 000 in negative settlement residues in New South Wales. In total these events led to more than \$14 million in negative settlement residues.

⁵ 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.

⁶ AEMC 2013, [Issues Paper, Management of negative inter-regional settlements residues](#), 18 April 2013, Sydney.

⁷ AEMO 2013, [Comments on Issues Paper, Management of negative inter-regional settlements residues](#), p3, 31 May 2013, Melbourne

⁸ 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.

Interconnector flows and SRAs

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.

Counter-price flows, however, decrease the value of holding SRA units.⁹ 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 a lower cost, brought about by competition. 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 (i.e. not the “spot price” region) of the NEM is exposed to the risk of price separation between the regions. When significant divergence occurs, that counter-party is subject to financial loss. 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 price region into a high price region are constrained due to disorderly bidding, the amount of inter-regional settlement residues that accrue (the price difference multiplied by the flow of energy) 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.¹⁰

The impact of disorderly bidding on interconnector flows and settlement residues greatly reduces the value of SRA units and makes SRA units a less firm method of managing risks associated with inter-regional contracting.

Technical versus commercial parameters

The parameters a participant submits as part of its offer are designed to reflect its commercial objectives. Certain elements, however, are required by the rules to reflect the technical characteristics of the plant such as those related to ancillary service parameters or when a generator declares itself inflexible and is unable to follow dispatch instructions.

The rules are currently silent on other technical elements submitted, such as ramp rates (except when these rates are very low) and circumstances where a generator decides to commit its generator using the fast start inflexibility provisions (FSIP). This is despite the dispatch process treating these parameters as if they do reflect the technical characteristics of plant.

⁹ 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 500 then it would receive one-fifth 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.

¹⁰ 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. The settlement residues returned to SRA unit holders under these conditions is zero.

The purpose of this rule change is to align all of the rules related to technical parameters to ensure they at all times they reflect the true characteristics of plant and cannot be manipulated for short term commercial gain in the spot market .

Figure 1 shows how NEMDE prioritises the constraint violation penalties (CVP) associated with various selected constraints. CVPs (expressed as a multiple of the price cap) represent the incremental cost incurred if a constraint equation is violated. Higher CVPs are associated with higher priority constraint types. NEMDE prioritises the order for relaxing constraints that cannot be simultaneously satisfied.

Figure 1: Constraints and Constraint Violation Penalties

| Constraint type | CVP | Comment |
|---------------------------------|------------|---|
| Ramp rate | 1155 | NEMDE takes as given as it cannot second guess generator capability |
| FSIP (T1, T2, T3, T4) | 1130 | NEMDE cannot second guess generator capability |
| Minimum and fixed loading level | 380 | NEMDE cannot second guess generator capability |
| Satisfactory network limit | 360 | Beyond this may damage equipment |
| Secure network limit | 35 | Beyond this may damage equipment following a credible contingency |

Figure 1 highlights that ramp rates and dispatch inflexibility profiles are considered high priority constraints (indeed, ramp rates are the highest order constraint). This is because AEMO is dependent on what generators submit. The importance of these constraints is evidenced by the fact that ramp rate and FSIP constraints have higher CVPs than satisfactory and secure network limits.

The AER considers this conflict in the role of ramp rates and FSIPs must be resolved. Arguably, requiring generators to limit their ramp rate bids and rebids and FSIPs to levels that correspond to the actual physical or technical capability of their plant, is just a refinement to meet the original intent of the 2008 rule change and would make the treatment of these parameters in the rules consistent with the inflexibility requirements of 3.8.19(a) and frequency control ancillary service offers in 3.8.7A. The AER considers that, if made, this rule change proposal would further enhance system security and significantly reduce the impact of disorderly bidding.

Ramp Rates

Current Rules

Clause 3.8.6(a)(2)(iii) requires a scheduled generator’s dispatch offer to specify for each of the trading intervals in a trading day, an up ramp rate and a down ramp rate. This enables AEMO to issue dispatch instructions to generators to vary their output to match supply and demand consistent with the offer. Participants have the ability to rebid their ramp rates during a dispatch interval with effect from the next dispatch interval.

Under clause 3.8.3A generators must specify a ramp rate that is 3MW/min or higher (or 3 per cent for generators below 100 MW in capacity) unless there is a technical limitation on

their plant.¹¹ For most generators this requirement is towards the lower end of its technical capability. Generators must provide a reason to AEMO electronically whenever a rebid is submitted. In the event the ramp rate is less than 3MW/min, the reason must reflect the technical reason why a higher ramp rate cannot be achieved. AEMO publishes the reasons submitted by participants and the AER monitors them.

The 3 MW/min minimum requirement followed a proposal from the AER in 2008 to amend the relevant clauses of the rules (the rule became effective from January 2009).¹² Prior to this rule change, generators were able to offer or rebid ramp rates as low as 1 MW/min. The level of 3 MW/min was chosen as a pragmatic compromise between the maximum technically possible and ensuring enough ramping capability was available to AEMO to manage system security.

Example of the implications of the current Rules

Snowy Hydro's Tumut facility is registered as a single aggregated unit (despite being made up of 6 generation units) and has a maximum capacity of 1800 MW.

Most of the time, Tumut's ramp down rate is in the order of 30 MW/min. However, its offer is often 200 MW/min. This means it can ramp down from maximum output to zero in less than 10 minutes. However, if it reoffers its ramp rate to 3 MW/min, the current minimum allowed, (e.g. for commercial reasons such as when prices are high and a constraint is binding that is trying to force Tumut to lower output levels), it would take 10 hours to ramp down to zero output. The AER considers this demonstrates how generators can use ramp rates (a technical parameter) to their commercial advantage.

The use of ramp rates for commercial rather than technical reasons is a systemic, long-standing issue. The AER has written of many instances (in Spot prices above \$5000/MWh reports and Weekly Market Analysis reports¹³) where ramp rates have been used for commercial reasons rather than technical reasons. Several of these examples are included in the following.

Spot price events above \$5000/MWh in New South Wales, 2009 and 2010

Congestion in New South Wales in late 2009 and into mid 2010 (primarily associated with the repeated binding of the N>>N-NIL_S constraint) saw the spot price in New South Wales exceed \$5000/MWh on 7 and 17 December 2009, 4 and 22 February 2010 and 10 August 2010.¹⁴ On several of these days the spot price exceeded \$5000/MWh for several

¹¹ For simplicity, whenever the minimum ramp rate is stated it should be read as 3MW/min or 3 per cent for generators below 100 MW in capacity.

¹² AEMC 2009, *Ramp Rates, Market Ancillary Service Offers, and Dispatch Inflexibility*, Rule Determination, 15 January 2009, Sydney.

¹³ In accordance with clause 3.13.7 of the rules, the AER is required to monitor and report on significant variations between forecast and actual prices. The AER provides this in its weekly electricity reports including detailed analysis when the spot price exceeds three times the weekly average in a region and \$250/MWh or is less than -\$100/MWh. In addition the AER is required to publish a report when the spot price in a region exceeds \$5000/MWh.

¹⁴ This constraint managed flows across one of the Mt Piper to Wallerawang 330 kV lines in the event of the loss of the second Mt Piper to Wallerawang line.

trading intervals.¹⁵ Common to each day was the use of ramp rates by generators for commercial reasons, which amplified the market impact of the congestion.

Rebidding of down ramp rates by Delta Electricity (from 5 MW/min) to the minimum allowable of 3 MW/min at its Mt Piper units and a reduction in available capacity at its Wallerawang units significantly contributed to the high price events in December and February.¹⁶ On three of the four days they also shifted substantial capacity into high price bands.

Given their close proximity to the relevant network elements, the Mount Piper and Wallerawang units' coefficients on the constraint were much greater than for other generators or interconnectors.¹⁷ By reducing the ramp down rate to a low value, the ability for NEMDE to 'constrain-off' these generators is limited. As a result, to manage flows on the network other generators and interconnectors needed to be constrained, but by a larger amount. This saw large quantities of low-priced generation constrained off and limitations on the interconnectors, thus limiting imports into New South Wales.

At the same time as it reduced the ramp down rates on its Mt Piper units, Delta Electricity increased its ramp up rate from 5 MW/min to 10 MW/min. Increasing its ramp up rate meant that when the constraint ceased binding (it was not binding continuously) NEMDE would ramp the generator up again at a faster rate only to then ramp it down at a slower rate when it bound again. On 7 and 17 December and 4 February the rebid reasons relating to the change in ramp rates related to constraint management. On 4 February, the rebid reason related to the trip of another unit in its portfolio. In other words, the rebid reasons reflected commercial considerations, not technical plant reasons.

The rebidding by Delta Electricity exacerbated the already tight supply conditions. For example, import capability from Victoria and Queensland on 7 December was up to 2200 MW lower than forecast 12 hours ahead and about 600 MW of low-priced New South Wales generation was constrained off. On 7 December around \$586 000 of negative settlement residues accrued, \$356 000 of which accrued across the New South Wales to Queensland interconnector (into Queensland) and around \$230 000 was accrued across the Victoria to New South Wales interconnector (into Victoria).

Other generators also rebid their ramp rates opportunistically for commercial reasons to take advantage of the tight market conditions in New South Wales on these days. For example, on 7 December and 4 February, Macquarie Generation rebid the ramp down rates of its Bayswater and Liddell units from 5 MW/min and 4MW/min respectively to the minimum allowable of 3 MW/min to reduce the impact of the constraint on its dispatch. At the same time it increased its ramp rate up rate from 4 MW/min to 6 MW/min and 12 MW/min respectively. The reason given for these change in ramp rates related to constraint management.

The largest change in ramp rates for commercial reasons during this period was by Snowy Hydro at Tumut Three on 4 February. To prevent being constrained off, Snowy Hydro rebid

¹⁵ The relevant *Spot prices above \$5000/MWh* reports can be found by clicking [here](#).

¹⁶ In 2011 the New South Wales Government sold the electricity trading rights of some state owned power stations. Energy Australia has the trading rights for Mt Piper and Wallerawang power stations.

¹⁷ The effects of these coefficients have been written about in detail in the relevant *Spot prices above \$5000/MWh* reports, which can be found by selecting the "\$5000 report" category [here](#).

its ramp rate from 200 MW/min to the minimum allowable of 3 MW/min. Snowy undertook similar behaviour on 10 August 2010 when the spot price in New South Wales exceeded \$5000/MWh in two occasions. On the day, Snowy Hydro rebid the ramp down rate at Tumut Three and Upper Tumut from 200 MW/min and 130 MW/min, respectively, to the minimum allowable level of 3 MW/min. The reason for the rebids related to previously un-forecast prices at the price cap. They also bid capacity to the price floor.

Spot price event above \$5000/MWh in Victoria, 22 April 2010

The events of 22 April 2010 saw the price in Victoria exceed \$5000/MWh for seven trading intervals.¹⁸ 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, Snowy Hydro's Murray generator was being constrained down from high output levels at 3 MW/min. Murray's ramp down rate had been 200 MW/min prior to the high price periods, which Snowy Hydro changed through a rebid. The reason for the rebidding of the ramp rates related to prices being higher than forecast – i.e. commercial reasons. Around the same time as Snowy Hydro rebid its ramp rates it moved capacity into negative prices. 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.

High Queensland prices during 2011, 2012 and 2013

Congestion on the transmission lines between Calvale-Wurdong and Calvale-Stanwell (in the vicinity of Gladstone) has led to highly volatile prices in Queensland and significant negative settlement residues since July 2011.

Analysis by the AER shows that the use of ramp rates for commercial reasons has exacerbated the market impacts of this network congestion. In December 2012 the AER published a Special Report entitled *The impact of congestion on bidding and inter-regional trade in the NEM*.¹⁹

The report explained how, as a result of a restructure in July 2011, CS Energy now operates the power stations located on either end of the Calvale-Wurdong line (Gladstone and Callide power stations). CS Energy can contribute to causing congestion 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. This can then cause the constraint to bind, leading to the constraining on or constraining off of generators and QNI. At times CS Energy would rebid to reduce Callide's ramp down rates so that when the constraint bound Callide can only be decreased at a slow rate (3 MW/min).

¹⁸ AER 2010 [Spot prices above \\$5000/MWh report, Victoria, 22 April 2010](#)

¹⁹ In December 2012 the AER published a Special Report entitled *The impact of congestion on bidding and inter-regional trade in the NEM* and in March 2013 the AER made a submission to the Productivity Commission's *Electricity Network Regulatory Frameworks Review* entitled *Possible options for interim solutions to congestion-related disorderly bidding*. Both reports are [attached](#).

Analysis of the commercial use of ramp rates causing or exacerbating network congestion

The AER has reported numerous examples of network congestion leading to large changes in the dispatch of generation and price fluctuations. During such periods, some generation is ramped up and other generation is ramped down but the changes for each unit are always limited by the ramp rate being offered. This can lead to a large dislocation of dispatch and a large un-forecast change in price (with the price often jumping to close to the price cap). The price spike often disappears as quickly as it arose, as over the following dispatch intervals sufficient generation has ramped to new levels so that economic dispatch for most generation can resume.

To attempt to quantify the impact of generators having higher ramp rates during these periods, the AER analysed several individual dispatch intervals during December 2012 and January 2013 when short-term congestion-related price spikes occurred. Using AEMO's NEMDE-queue facility, very small increases to the ramp up or down rate of generators were made. The results showed that with only small changes to the offered ramp rates of a limited number of generators,²⁰ the increased degree of freedom available to the dispatch algorithm meant that the extreme price volatility did not occur.

Relative advantage of large aggregated generators

As it currently stands, the 3 MW/min rule creates an advantage for large aggregated generators that can significantly exacerbate the market impacts of network congestion. Large aggregated generators, such as Snowy Hydro's upper and lower Tumut facilities (and the Murray facilities), which are capable of a ramp rate of 200 MW/min, on occasion rebid their ramp down rates to the minimum allowable of 3 MW/min in the presence of congestion. In the AER's view this results in a disproportionate burden on other generators or interconnectors as their output is changed instead of Tumut. This in turn increases the risk profile of those other generators and lessens their ability to hedge. The large impact on the flows across interconnectors when certain constraints bind also reduces the effectiveness of inter-regional settlements residues to purchasers of those rights, which reduces the ability to hedge between regions. Had the rapid reduction in ramp rate down not occurred, flows would not have been counter price and negative settlement residues would not have occurred (which in turn flows through to transmission use of service (TUoS) prices).

The issue of fairness/equity between generators has been considered by the AEMC previously. In the AER's 2008 rule change proposal (where the AER proposed that the 1MW/min minimum be changed to 3MW/min minimum), the AEMC's draft decision proposed that the minimum apply to the individual generating units that form part of an aggregated unit. Therefore, taking Tumut as an example, Tumut would have been treated as six units, so its minimum ramp rate would be 18 MW/min. However, Snowy (and others) argued against this, and the AEMC moved away from this approach in its final decision, so that aggregated units such as Tumut are treated, in effect, as a single unit. The AER understands this is the approach taken by participants, including Snowy specifying the maximum ramp rates requirements of Schedule 3.1 of the rules.

²⁰ Generators with high coefficients in the constraint equations have the greatest impact on relieving congestion, so it was these generators which the AER focussed on. For more explanation of coefficients in constraint equations, see Appendix C.

Proposed Ramp Rate Rule change

The AER has considered a range of different options in relation to ramp rate rule changes, including four alternatives to achieve the objective of placing a greater restriction on generator ramp rates (the arguments for and against each approach is contained in Appendix A).

The AER's preferred option (and the subject of this Rule change proposal) is to require generators to always submit ramp rates that reflect their technical capability at the time. This essentially means providing a ramp rate to AEMO that is the maximum the generator can safely attain at that time. The rule change proposal would apply equally to scheduled and semi-scheduled generators, scheduled network services and scheduled loads. Proposed changes to clause 3.8.3A to achieve this are contained in Appendix D. The AER's proposed approach to monitoring and enforcing compliance with this requirement is described under *AER's proposed approach to compliance*.

Dispatch inflexibility profile

Clause 3.8.19(d) provides a fast start generator with the discretion to provide an FSIP as part of its dispatch offer. Essentially, an FSIP is data that market participants (including generators) may provide to AEMO to specify dispatch inflexibilities in respect of their units. This mechanism is used by fast start plant such as gas turbines, to inform the dispatch process of minimum start and stop times, and of minimum safe operating levels.

Like ramp rates, an FSIP is a set of technical parameters that is used in the dispatch process to restrict the way a generator can be dispatched. The AER considers that like ramp rates, the intention of clause 3.8.19(e) is that a generator submits an FSIP that reflects its technical capabilities. AEMO must endeavour to dispatch the generator within these technical capabilities. As shown in figure 1 above, the CVP associated with violating an FSIP constraint is higher than for satisfactory and secure network limits.

However, the rules are imprecise and participants can change these dispatch inflexibility profiles through the rebidding process for any reason. That is, as the rules currently stand, participants can use these technical parameter for commercial advantage.

This rule change proposal seeks to require fast start generators to submit an FSIP that reflects the technical limitations of the plant. On the basis that this was the original intention of the clause, the AER does not consider that this proposed rule change proposal would create unnecessary hardships for fast start generators. Proposed changes to clause 3.8.19(d) to achieve this are contained in Appendix D. The AER's proposed approach to monitoring and enforcing compliance with this requirement is described under *AER's approach to compliance*.

AER's proposed approach to compliance

The AER appreciates that, given the variable and technical nature of ramp ramps, concerns may be raised with respect to how such a change to the rules may be enforced. Accordingly, to provide further clarity on how the proposed rule would operate in practice and how the AER would enforce it, the AER would amend its *Rebidding and Technical Parameters*

Guideline. The AER would consult on this in accordance with the rules consultation procedures.

Generally speaking, registered participants would be required to ensure the ramp rate being offered reflects the maximum the generator can achieve under the conditions at the time, or expected output of the plant under anticipated conditions in the forecasting horizons. As outlined in the *Rebidding and Technical Parameters Guideline* ramp rates may be provided through other mechanisms, including directly from the power station through the Supervisory Control And Data Acquisition (SCADA) system. This must also reflect the maximum the generator can achieve under the conditions at the time. The more limiting of the offer and that provided through SCADA is used in dispatch. If the ramp rate provided through SCADA is more restrictive than a rebid to reflect this must be made as soon as possible.

The AER recognises that when submitting offers, bids or rebids for a future timeframe (i.e. in the pre-dispatch timeframe), it may be difficult for generators to precisely determine the maximum ramp rate at that future point in time. In this case the AER would expect participants to submit ramp rates that are typical of what the generator could achieve based on the forecast conditions. However, the AER would expect that closer to the dispatch timeframe participants would be more aware of the maximum capability of their plant and that their offered ramp rate should be refined to reflect this.

In considering compliance with the proposed rule it is instructive to consider the obligation that currently exists in the rules for compliance with dispatch instructions. In 2006 the AER issued a compliance bulletin outlining its approach to monitoring the responsibilities of participants to follow dispatch instructions as required by clause 4.9.8(a) of the rules.²¹ The objective of this compliance bulletin was to clarify the AER's expectations, including the approach the AER intends to take with respect to monitoring compliance with these provisions of the Rules. The bulletin states:

The AER also recognises that while Registered Participants must endeavour to comply with dispatch instructions exact compliance with dispatch instructions in every dispatch interval is a physical impossibility. Accordingly, the AER does not intend to pursue a breach of clause 4.9.8(a) with respect to minor departures from dispatch instructions that occur despite the best endeavours of a Registered Participant to comply.

In a similar way the approach the AER intends to take with respect to monitoring compliance with proposed rule would be outlined in a revised version of the *Rebidding and Technical Parameters Guideline*. In principle this would require that if the expected ramp rate in the offer differed materially from its technical maximum capability then it would be required to submit a rebid to vary its ramp rate.

Currently under the rules, if a participant provides a ramp rate under 3 MW/min it must simultaneously provide AEMO with a brief, verifiable and specific reason. The brief, verifiable and specific reason must relate directly to the technical reason preventing the relevant generating unit, scheduled load or scheduled network service from attaining the required minimum ramp rate. However, under this rule change proposal, each time a participant determines that the offered ramp rate differs materially from its technical

²¹ AER 2006, [Compliance Bulletin No 1 - complying with dispatch instructions](#)

maximum capability then it would be required to submit a rebid to vary its ramp rate, and the brief, verifiable and specific reason would need to directly relate to the technical reason for doing so. The amended *Rebidding and Technical Parameters Guideline* will outline when a change in ramp rate warrants a technical rebid reason. As is the case under the current rules, the AER would be entitled to require that the generator provide additional information to substantiate and verify the reason provided.

As a matter of principle, the AER would take a pragmatic approach to monitoring and enforcing compliance with proposed clause 3.8.3A. Specifically, we would generally not be examining precise ramp rate values at all times, and we would not expect to pursue a breach of clause 3.8.3A with respect to minor variations in offered ramp rates. Instead we would focus our attention on ramp rates under certain market conditions where there may exist a driver to rebid a ramp rate for commercial rather than technical reasons. For example, the AER would be likely to check the ramp rates of generators when there are high prices and network congestion is causing NEMDE to limit their output, to assess whether they appear within the range of their typical maximum ramp rate. Where appropriate the AER may also engage independent experts to verify actual plant capabilities.

When deciding on an appropriate response upon the discovery of a potential breach of clause 3.8.3A, the AER would, as it does with all potential breaches, take into account all relevant facts including:

- (a) the nature and extent of the breach;
- (b) the nature and extent of any loss or damage suffered as a result of the breach;
- (c) the circumstances in which the breach took place; and
- (d) whether the relevant participant has engaged in any similar conduct.²²

On the basis of these factors, the AER will determine an appropriate response. If the new clause 3.8.3A remains a civil penalty provision (which the AER would support), the AER could (as is currently the case under 3.8.3A(d)) issue an infringement notice or institute legal proceedings.

In terms of the proposed changes to the clauses relating to FSIPs, new proposed clause 3.8.19(h) (as shown in Appendix D) would require participants who submit an FSIP to ensure the parameters reflect the actual MW capacity and time inflexibilities of the generating unit at the time. As for the case for ramp rates, the AER would take a pragmatic approach to monitoring and enforcing compliance with the requirement to submit a “technical” FSIP. Again, the AER would not examine precise FSIP parameters at all times. Instead we would focus our attention on FSIPs under certain market conditions where there may exist a driver to rebid an FSIP for commercial rather than technical reasons. For example, we may examine whether the unit’s “T” times are a true reflection of its technical capability under high price conditions. Reinforcing the importance of this proposed clause, it would also attract a civil penalty.

²² AER 2010 [Compliance and Enforcement Statement of Approach](#), December 2010

D How the proposal contributes to the National Electricity Objective

The national electricity objective (the objective) is stated in section 7 of the National Electricity Law as being:

to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to –

(a) price, quality, safety, reliability and security of supply of electricity;

(b) the reliability, safety, and security of the national electricity system.

The AER considers the proposed Rule change will contribute to the objective in several key ways, as follows.

System security

Requiring generators to bid a technical ramp rate at all times will provide AEMO with the ability to move generators more quickly to alleviate a constraint. Under the section *Example of the implications of the current Rules*, (above) it was highlighted that if large generators like Snowy Hydro's Tumut facility reset their ramp rate to 3 MW/min, the current minimum allowed, (e.g. for commercial reasons such as when prices are high and a constraint is binding that is trying to force Tumut to lower output levels), it would take 10 hours to ramp down to zero output. However, Snowy Hydro's Tumut facility is also generally capable of achieving a ramp-down rate of 200 MW/min. Requiring the generator to bid the maximum ramp rate it is technically capable of achieving at the time would enable the constraint to be alleviated more quickly, hence enhancing system security. This contributes to the objective through improving the safety, reliability and security of supply of electricity and the national electricity system.

Price of supply of electricity

As discussed above, over the last three years 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. The increased prevalence of counter price flows has also led to increased transmission use of service (TUOS) charges in importing regions (which ultimately flows through to consumers' energy bills).

Some retailers own generation assets as a "physical" hedge to mitigate spot market exposure. However, because the price spikes associated with disorderly bidding are often unforecast and occur at short-notice, peaking plants (which typically take longer than 5 minutes to start) are not as effective at hedging which increases costs.

Further, increased volatility in the wholesale market affects the price of hedge contracts, which will flow through to retail tariffs. Prices for hedge contracts are based on the market's

expectation of spot prices adjusted by a risk premium. Increased spot volatility leads to an expectation of similar volatility in the future, which can lead to an increase in the risk premium.

Efficient investment in transmission infrastructure

A costly approach to addressing the problem of congestion related disorderly bidding would be to “build the problem out” through increased investment in transmission infrastructure. The AER considers that implementing this partial solution (of requiring generators to bid and rebid the maximum ramp rate they are capable of achieving) while the AEMC undertakes the work required to potentially implement the longer term solution of the optional firm access model may negate short-term inefficient investment in transmission infrastructure, thereby promoting longer term efficient investment in transmission infrastructure.

E Costs and benefits and potential impacts on those likely to be affected

Potential costs

Plant wear and tear

Some participants may argue that there are costs associated with requiring their plant to operate at the technical ramp rate limits at all times (compared with the current lower limit of 3 MW/min). Operating plant at, or close to, its technical ramp rate limits can lead to rapid changes in output up or down from time to time. It could be argued that in the extreme, this could increase wear and tear and result in associated increased maintenance costs.

However, the AER does not consider this to be a valid argument because generators have the ability to rebid volumes within price bands to limit the amount and the frequency by which their output changes, thereby negating potential wear and tear. For example, if a generator is the marginal unit in the region (or the NEM) then it could be ramped up and then down and then up again from dispatch interval to dispatch interval. To avoid this, the generator could decrease its availability in the price band that it is currently being varied within.

Potential to de-engineer plant

It may also be argued that requiring generators to bid their technical limits at all times may give them the incentive to “de-engineer” their plant to reduce the technical ramp rate capability. However, the AER considers it is unlikely this would happen. The reason is, for the vast majority of the time (apart from periods of local congestion leading to disorderly bidding) generators have an incentive to maintain flexible plant so they can respond quickly to high or low prices. The AER understands, however, that when constraints bind, this ability to be moved rapidly can be financially damaging, because generators can be constrained off when they would rather be generating and receiving a high price. However, this is using ramp rates as a commercial parameter.

Benefits of Rule change

The AER considers that, if made, this rule proposal would mitigate the most egregious cases of disorderly bidding and would have broad and long term benefits to the market as a whole. The benefits, as discussed above, would be a reduced ability for generators to manufacture

congestion, reduced spot price volatility (and a resultant improved ability for intra-regional hedging), reduced counter price flows across interconnectors, improved firmness across interconnectors during high spot price events (and a resultant improved ability for inter-regional hedging), a reduction in negative inter-regional settlement residues and an improvement in SRA proceeds. The AER considers there would be an improvement in interregional competition, and ultimately end-use consumers would benefit through lower prices.

Another strong advantage of requiring generators to bid in their technical ramp rates is that it would also help to ensure that AEMO has at its disposal the highest level of flexibility that the market can provide to aid in the management of system security and promote the efficiency of dispatch. A large number of short duration price spikes occur following relatively small step changes in supply or demand (reductions in either network or generator capacity or increases in demand). Limited ramp rate capability results in the dispatch of higher priced capacity than would otherwise occur and can lead to system security issues when NEMDE does not have enough capability to move generators to resolve network constraints.

Alternatives for a greater restriction on generator ramp rates

Approach A: 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 on the 2008 rule change proposal). 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. The disadvantage to this approach is that large individual units would still be able to submit a very low ramp rate compared to its technical capability.

Approach B: One approach might be to change the Electricity Rules 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 C: A further alternative would be to change the 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/min, 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 D.

Approach D: This approach would require generators to bid a technical ramp rate at all times. This is the preferred approach and is explained in detail in the main body of this paper.

Appendix B

Tables A1 and A2 show that on 23 occasions since December 2009 disorderly bidding as a result of network congestion has led to significant counter price flows between Victoria and New South Wales. Tables A1 and A2 list each event where disorderly bidding led to more than \$150 000 in negative settlement residues into New South Wales and 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 occurred.

Table A1: Summary of high cost recent examples of counter price flow into New South Wales

| Date | Maximum spot price (\$/MWh) | Maximum counter price flow (MW) | Negative settlement residue (\$) |
|--------------|------------------------------------|--|---|
| 9/02/2010 | 7847 | 560 | 1 150 000 |
| 10/02/2010 | 1489 | 497 | 717 000 |
| 21/04/2010 | 2093 | 496 | 1 143 000 |
| 22/04/2010 | 9999 | 641 | 17 491 000 |
| 21/06/2010 | 1756 | 894 | 259 000 |
| 22/10/2010 | 2470 | 1108 | 983 000 |
| 28/11/2010 | 115 | 1417 | 157 000 |
| 31/01/2011 | 9597 | 174 | 440 000 |
| 30/05/2011 | 1814 | 1039 | 1 032 000 |
| 31/05/2011 | 166 | 908 | 226 000 |
| 2/07/2012 | 4364 | 126 | 172 000 |
| 11/09/2012 | 2221 | 769 | 1 325 000 |
| 13/12/2012 | 2185 | 316 | 229 000 |
| 18/02/2013 | 1937 | 259 | 261 000 |
| 28/05/2013 | 1426 | 309 | 212 000 |
| Total | | | 25 797 000 |

Table A2: Summary of high cost recent examples of counter price flow into Victoria²³

| Date | Maximum spot price (\$/MWh) | Maximum counter price flow (MW) | Negative settlement residue (\$) |
|--------------|------------------------------------|--|---|
| 7/12/2009 | 7715 | 37 | 230 000 |
| 22/01/2010 | 4514 | 205 | 214 000 |
| 4/02/2010 | 5541 | 1365 | 5 025 000 |
| 11/02/2010 | 1998 | 152 | 173 000 |
| 26/03/2010 | 1836 | 226 | 205 000 |
| 13/04/2010 | 3081 | 529 | 805 000 |
| 29/06/2010 | 4987 | 194 | 472 000 |
| 9/11/2011 | 6498 | 685 | 1 734 000 |
| Total | | | 8 858 000 |

²³ The 16 October 2012 event is not included as negative settlement residues were less than \$150 000.

Table A3 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 A3: Significant counter price flows related to congestion around Gladstone

| Date | Maximum spot price (\$/MWh) | Maximum counter price flow (MW) | Negative settlement residue (\$) |
|------------|-----------------------------|---------------------------------|----------------------------------|
| 5/09/2011 | 2117 | 569 | 371 000 |
| 12/01/2012 | 1757 | 917 | 993 000 |
| 15/01/2012 | 228 | 1148 | 183 000 |
| 27/01/2012 | 509 | 966 | 303 000 |
| 29/01/2012 | 2080 | 1257 | 1 272 000 |
| 14/02/2012 | 360 | 876 | 222 000 |
| 20/02/2012 | 503 | 667 | 185 000 |
| 21/02/2012 | 392 | 1004 | 196 000 |
| 22/02/2012 | 438 | 772 | 256 000 |
| 2/03/2012 | 317 | 872 | 308 000 |
| 3/03/2012 | 265 | 854 | 272 000 |
| 4/03/2012 | 339 | 491 | 165 000 |
| 5/03/2012 | 289 | 1155 | 248 000 |
| 6/03/2012 | 268 | 898 | 202 000 |
| 9/03/2012 | 260 | 1079 | 278 000 |
| 10/03/2012 | 196 | 1118 | 234 000 |
| 23/03/2012 | 396 | 969 | 297 000 |
| 25/08/2012 | 646 | 785 | 346 000 |
| 30/08/2012 | 463 | 900 | 179 000 |
| 31/08/2012 | 311 | 1147 | 302 000 |
| 1/09/2012 | 603 | 1078 | 293 000 |
| 3/09/2012 | 370 | 1112 | 512 000 |
| 8/09/2012 | 408 | 978 | 246 000 |
| 27/10/2012 | 1085 | 934 | 410 000 |
| 5/12/2012 | 368 | 826 | 359 000 |
| 2/01/2013 | 1953 | 692 | 743 000 |
| 12/01/2013 | 879 | 654 | 272 000 |
| 13/01/2013 | 2918 | 547 | 206 000 |
| 14/01/2013 | 2499 | 606 | 858 000 |
| 16/01/2013 | 451 | 342 | 171 000 |
| 17/01/2013 | 550 | 894 | 590 000 |

| | | | |
|-------------------|------|------|-------------------|
| 18/01/2013 | 1989 | 808 | 808 000 |
| 19/01/2013 | 544 | 678 | 169 000 |
| 20/01/2013 | 1345 | 832 | 835 000 |
| 8/02/2013 | 278 | 900 | 338 000 |
| 10/02/2013 | 297 | 1057 | 199 000 |
| 14/02/2013 | 214 | 674 | 313 000 |
| 15/02/2013 | 385 | 779 | 335 000 |
| Total | | | 14 469 000 |

How constraint equations operate

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 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.²⁴ 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.²⁵ A binding constraint equation affects dispatch until the constraint no longer binds.²⁶

²⁴ If the constraint equation is not satisfied it is termed as 'violated'.

²⁵ Constraint equations can be expressed as $LHS \leq RHS$ or $LHS \geq RHS$. For the purposes of this report, the descriptions of constraint equations are limited to $LHS \leq RHS$. These are the most common types of constraint equations used to manage network limits.

²⁶ 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.

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.

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'.

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 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.²⁷

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 *Constraint Formulation Guidelines*.²⁸ 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).

²⁷ 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.

²⁸ AEMO 2010, [Constraint Formulation Guidelines](#)

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.

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/min or higher unless there is technical limitation on their plant. An interconnector is treated as having no ramp rate and therefore NEMDE can rapidly change the level and direction of flows on interconnectors.

Suggested drafting

Suggested amendments to clause 3.8.3A (Ramp Rates) of the National Electricity Rules

Amend clause 3.8.3A as follows (insertions underlined and deletions in strikethrough):

3.8.3A Ramp Rates

(a) This clause 3.8.3A applies to a *Scheduled Generator, Semi-Scheduled Generator or Market Participant* with *generating units, scheduled network services* and/or *scheduled loads* providing *ramp rates* to AEMO in accordance with the following clauses:

(1) with respect to notification of scheduled capacity prior to *dispatch*:

- (i) clause 3.8.4(c);
- (ii) clause 3.8.4(e);
- (iii) clause 3.8.4(d);

(2) with respect to offers for *dispatch*:

- (i) clause 3.8.6(a)(2);
- (ii) clause 3.8.6(g);
- (iii) clause 3.8.6A(b);
- (iv) clause 3.8.7(c); and

(3) with respect to *rebids*, clause 3.8.22(b)

Amend clause 3.8.3A(b) as follows:

(b) ~~Subject to clauses 3.8.3A(e) and 3.8.3A(i), a~~ A *Scheduled Generator, Semi-Scheduled Generator or Market Participant* to which this clause 3.8.3A applies must provide an up *ramp rate* and a down *ramp rate* to AEMO for each *generating unit, scheduled network service* and/or *scheduled load* that is the maximum the relevant generating unit, scheduled load or scheduled network service can safely attain at that time.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

(1) **[Deleted]**

(2) **[Deleted]**

Note [Deleted]

(c) **[Deleted]**

(d) **[Deleted]**

(e) **[Deleted]**

- (c) ~~(f)~~ The *AER* may require, upon written request, the *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* to provide such additional information as it may require from time to time to substantiate and verify the ~~reason~~ ramp rates provided in accordance with clause 3.8.3A~~(e)~~(b).
- (d) ~~(g)~~ The *AER* must exercise its powers under clause 3.8.3A~~(c)~~(f) in accordance with any guidelines issued by the *AER* from time to time in accordance with the *Rules consultation procedures*.
- (h) **[Deleted]**
- (i) **[Deleted]**
- (j) **[Deleted]**

Note **[Deleted]**

Suggested amendments to clause 3.8.19 (Dispatch inflexibilities) of the National Electricity Rules

Amend clause 3.8.19(e) and insert new clauses 3.8.19(h) (a civil penalty provision), 3.8.19(i) and 3.8.19(j) as follows (insertions underlined and deletions in strikethrough):

- (e) A *dispatch inflexibility* profile for a *generating unit* must contain the following parameters to indicate its MW capacity and time related *inflexibilities*:
- (1) The time, T1, in minutes, following the issue of a *dispatch instruction* by *AEMO* to increase its loading from 0 MW, which is required for the *plant* to begin to vary its *dispatch* level from 0 MW in accordance with the instruction;
 - (2) The time, T2, in minutes, that the *plant* requires after T1 (as specified in subparagraph (1)) to reach ~~a specified~~ its minimum MW *loading level*;
 - (3) The time, T3, in minutes, that the *plant* requires to be operated at or above its minimum MW *loading level* before it can be reduced below that level;
 - (4) The time, T4, in minutes, following the issue of a *dispatch instruction* by *AEMO* to reduce loading from the minimum MW *loading level* (specified under subparagraph (2)) to zero, that the *plant* requires to completely comply with that instruction;
 - (5) T1, T2, T3 and T4 must all be equal to or greater than zero;
 - (6) The sum (T1 + T2) must be less than or equal to 30 minutes; and
 - (7) The sum (T1 + T2 + T3 + T4) must be less than 60 minutes.

- (f) A *dispatch inflexibility profile* for a *scheduled load* must contain parameters to indicate its MW capacity and time related *inflexibilities*.
- (g) AEMO must use reasonable endeavours not to issue a *dispatch instruction* which is inconsistent with a *Scheduled Generator's*, *Semi-Scheduled Generator's* or *Market Participant's dispatch inflexibility profile*.
- (h) In the event that a *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* provides AEMO with a *dispatch inflexibility profile* in accordance with clause 3.8.19(d), the parameters provided in accordance with clause 3.8.19(e) and clause 3.8.19(f) must reflect the actual MW capacity and time *inflexibilities* of the *generating unit* at that time.

Note

This clause is classified as a civil penalty provision under the National Electricity (South Australia) Regulations. (See clause 6(1) and Schedule 1 of the National Electricity (South Australia) Regulations.)

- (i) The AER may require, upon written request, the *Scheduled Generator*, *Semi-Scheduled Generator* or *Market Participant* to provide such additional information as it may require from time to time to substantiate and verify the information provided in accordance with clause 3.8.19(e) and clause 3.8.19(f).
- (j) The AER must exercise its powers under clause 3.8.19(i) in accordance with any guidelines issued by the AER from time to time in accordance with the *Rules consultation procedures*.