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9 October 2014

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

Dear ~~Mr Pierce~~ John

Submission on National Electricity Amendment – Generator ramp rates and dispatch inflexibility in bidding

Please find attached the Australian Energy Regulator's (AER) submission regarding the AEMC's Draft determination published in August 2014.

We would be pleased to provide further assistance to the Commission on this important area of work. If you would like to discuss any aspect of this submission please contact Mr Peter Adams, Acting General Manager, Wholesale Markets, on (03) 9290 1465.

Yours sincerely

Paula Conboy
Chair
Australian Energy Regulator

AER Submission

National Electricity Amendment

Generator ramp rates and dispatch inflexibility in bidding

October 2014

AER reference 48613-D14/123566

Contents

1 Summary

The AER welcomes the opportunity to respond to the AEMC's draft determination on the Rule change in respect of *Generator ramp rates and dispatch inflexibility in bidding*.

In part, the AER's rule change proposal sought to require generators to bid the maximum ramp rate they are capable of achieving at the time, and, in the case of fast start plant, to submit a fast start inflexibility profile (FSIP) that reflects the technical capability of the plant. This would have aligned the operation of these parameters with other parameters that reflect the technical capability of a plant, namely ancillary services and a general inability to follow dispatch instructions due to abnormal plant conditions or other abnormal operating requirements.

We maintain that, contrary to the conclusions in the draft determination, ramp rates and fast start inflexibility profiles (FSIP) were envisaged and implemented in the market systems as representing technical characteristics of an offer or bid. The AER considers there would be value in ensuring that the treatment of such parameters in dispatch is consistent with the AEMC's interpretation.

The AEMC's draft determination is to require generators to submit a minimum ramp rate of at least one per cent of the unit's maximum capacity. The AER considers there is merit in this approach, as it will also deliver a solution to the disorderly bidding problem. Participants unable to meet one per cent will be required to submit a ramp rate that reflects the maximum the relevant generating unit, scheduled load or scheduled network service can safely attain at that time. This is consistent with our original proposal and reinforces the "technical" nature of the parameters.

Our submission shows that the AEMC's preferred rule would increase minimum available aggregate ramp rates in New South Wales, Victoria and Queensland. However, our analysis suggests that the preferred rule may lead to a reduction in minimum aggregate ramp rates under certain conditions in South Australia and Tasmania which may warrant closer examination before the AEMC reaches its final decision.

The Australian Energy Market Operator (AEMO) has indicated that it will be able to manage system security, having the power to issue directions if necessary. AEMO's use of this "safety net" power to maintain system security indicates that the market has not delivered a solution. Where the preferred rule change allows participants to reduce their offered minimum ramp rates, it may increase price volatility or lead to a more frequent need to use AEMO's direction powers.

History suggests that under certain conditions, generators selectively reduce their ramp rates to limit financial exposure. While this possibility would appear to have been reduced in New South Wales, Queensland and Victoria, under the preferred rule change the opportunity for this type of behaviour may increase in South Australia and Tasmania. South Australia has the highest penetration of intermittent renewables (wind and solar). It is not uncommon for only three or four conventional thermal units to be operating in the region. Most generators offer ramp rates higher than the minimum prescribed under the Rules. However, if the market conditions are right, under the preferred rule participants in South Australia and Tasmania could offer lower minimum ramp rates than currently apply and may be able to manage the price, thereby increasing volatility. The likelihood and materiality of this is difficult to assess.

While price volatility in and of itself is not bad, South Australia already is susceptible to limited ramping capability and has the highest volume weighted wholesale price of any NEM region. Increased price volatility may exacerbate that situation. We note that in the last 12 months, a lack of ramp up capability has cause high prices six times in South Australia, and fifteen times in

Queensland. If the draft rule is adopted the AER expects this to increase in South Australia where many generators are already only offering the minimum required by the current rule. The AER considers that in reaching its final decision, the AEMC must be certain that in line with the principle of doing no harm, the benefits gained in some regions do not come at the expense of artificially creating unnecessary volatility and adverse outcomes in South Australia and Tasmania.

We agree with the AEMC that the preferred rule would be relatively easy for participants to manage from a systems and administrative point of view, which would be beneficial to the market. It will increase the available ramp rate in most regions.

Finally, in its draft decision the AEMC highlighted that a complex rule change or onerous requirement may pose a potential deterrent to new developments. However, the AER understands that ramp rates are a very low order consideration in an investment decision compared to, for example, fuel sources, plant and equipment costs, or connection arrangements and congestion. Further, should a generator not be physically capable of achieving the required minimum ramp rates, there are prescribed processes available to advise the AER.

2 Discussion

2.1 AEMC analysis of regional aggregate minimum ramp rates

Table 4.2 in the draft determination presents the results of a desk top analysis to show the regional change in aggregate minimum ramp rate requirements should the AEMC's preferred rule be adopted. The AER has replicated the AEMC's methodology and the data from Table 4.2 is reproduced in rows A, C and F in Table 1.

Table 1: Regional change in aggregate minimum ramp rate requirements (MW/min)

	Region	NSW	QLD	SA	TAS	VIC
A	Current weighted average minimum (AEMC)	3	2.9	2.7	2.6	2.9
B	Current weighted average minimum with existing “exemptions”	2.8	2.7	2	2.3	2.6
C	Draft rule weighted average minimum (AEMC)	7.3	4	2.6	3.1	5.7
D	Draft rule weighted average minimum with existing “exemptions”	7.2	3.7	1.8	2.1	5.3
E	Draft rule weighted average minimum with existing and potential “exemptions”	5.3	3.2	1.8	2.1	4.8
F	Difference between draft rule weighted average minimum and current weighted average minimum (D-A) (AEMC)	4.4	1.1	0	0.5	2.8
G	Difference between draft rule weighted average minimum with existing and potential “exemptions” and current weighted average minimum with existing “exemptions” (E-B)	2.5	0.5	-0.2	-0.2	2.2

The AEMC's analysis assumes that all generators in each region are available to provide minimum ramp rates in accordance with the current rule. However, seven power stations[1] are currently permitted lower minimum ramp rates for technical reasons[2]. In addition, wind farms are unlikely to be able to provide ramp up[3] capability when most needed by the market. Taking these factors into account, Row B shows the reduced average minimum ramp rates for the current rules with the “exemptions” applied and ramp up rates for wind generators set to zero.

[1] These are Hazelwood, Milmerran, Playford, Osborne (only when in peaking mode), Lake Echo, Tarraleah and Yarwun. For the purposes of this paper, we say these generators have “exemptions”.

[2] Clause 3.8.3A (d) –requires an alternate ramp rate. That is the participant must provide a ramp rate to AEMO that is the maximum the relevant generating unit, scheduled load or scheduled network service can safely attain at that time.

[3] Unless a wind farm has been constrained down it is unlikely that a wind generator will be able to ramp up as their output is governed by the speed at which the wind is blowing at the time. Wind generators therefore tend to operate to the full capacity of the wind (i.e. they have no room to change their output in response to market conditions if needed).

Row C shows the AEMC's assessment of regional aggregate minimum ramp rates under the draft rule change. Like for Row B, Row D accounts for current exemptions and sets ramp up rates for wind generators to zero.

The results in Row D are lower than Row C for all regions.

We understand that additional generators may seek to rely on clause 3.8.3A(c) under the preferred rule as they would have difficulty in achieving ramp rates of one per cent of maximum capacity. As a result, these generators will be required to submit a ramp rate to AEMO that is the maximum the relevant generating unit, scheduled load or scheduled network service can safely attain at that time. Our analysis suggests that around eight additional power stations may seek to rely on clause 3.8.3A(c) under the draft rule. Row E applies these "exemptions" in addition to the those that currently rely on this provision and sets ramp up rates for wind generators to zero. This results in a further reduction in minimum aggregate ramp rates for New South Wales, Queensland and Victoria

Row F shows the difference between the existing rule and the draft rule according to the AEMC's analysis. The AEMC suggests that based on the results in this row, and on advice from AEMO, system security would be maintained under its preferred rule.

Row G shows the difference between row E and row B, delivering lower results for all regions than the AEMC's results in Row F. In line with what we see in the Medium Term Projected Assessment of System Adequacy (MTPASA), for South Australia we have assumed that one of the Pelican Point units is unavailable.

It is important to note, however, that the above is a desktop analysis and as such it can only provide a broad view of aggregate minimum ramp rates. Since this analysis assumes all units are able to contribute to the ramp requirement at all times it doesn't effectively account for real situations where low ramp availability occurs in a region. For this reason the AER has undertaken more detailed analysis, as follows.

2.2 Regional 2013-2014 5 minute dispatch analysis

To assess the minimum ramp up and down rate available in each region we generated two data sets of actual five minute data for the 2013-14 financial year. One of these data sets applies minimum ramp rates under the current rules while the other applies the minimum under the proposed draft rule. For the AEMC's draft rule data set we adjusted down ramp rates for the eight stations we consider would be likely to apply a maximum ramp rate less than one per cent of maximum capacity.

Table 2 shows the assumptions underpinning how the minimum ramp rate values were determined.

Table 2: AER approach to deriving minimum ramp rates by dispatch type

Generation type	*Treatment to establish the minimum in the data set*	
	Ramp up	*Ramp Down*
Mothballed plant and not operating scheduled generation	*0*	*0*
Scheduled Generation not operating	*0*	*0*
Semi scheduled wind generation	*0*[4]	*Ramp rate from rule or exemption*
Scheduled generation operating at minimum	*Ramp up from Rule or exemption*	*0*
Scheduled generation operating at Maximum	*0*	*Ramp rate from rule or exemption*
Operating Scheduled generation	*minimum of headroom*[5] *and Ramp rate from rule or exemption*	*Minimum of footroom*[6] *and ramp rate from rule or exemption*

The resulting data sets were used to derive the following curves for each region.

The curves below compare the regional aggregate minimum ramp rate for each region under the current rules (three MW/min or three per cent for generators under 100 MW) represented by the blue curve, to the AEMC's preferred rule of one per cent of maximum capacity, represented by the red line.

In interpreting the charts it must be remembered that they represent worst case scenarios. In other words, the curves examine what would be the likely impact on each region in the event all generators bid their ramp rates to the allowable minimums.

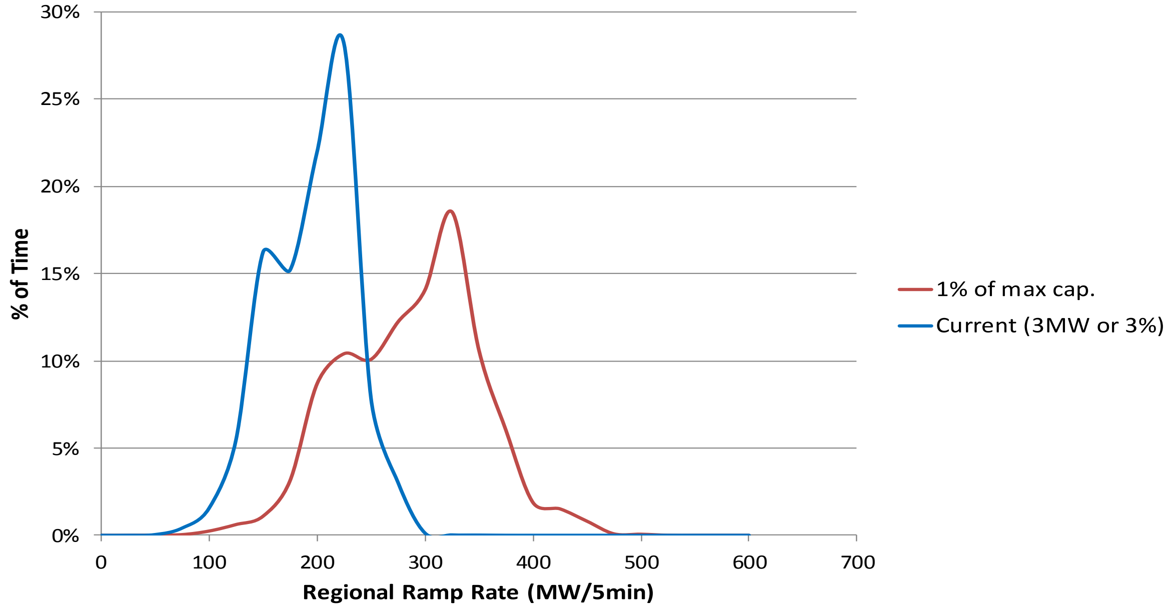
Our analysis shows that the AEMC's preferred rule may lead to an improvement in minimum aggregate ramp rates in New South Wales, Victoria, and Queensland compared to the current rules, as indicated by the red curves being to the right and wider compared to the blue curves. In other words, it is possible that the preferred rule could deliver higher minimum aggregate ramp rates for longer. However, Figure 1 toFigure 5 suggest that there may be a potential worsening (especially at critical times) in Tasmania and South Australia. These results are consistent with those shown in Table 1 above.

4 Semi-scheduled wind generators could provide ramp up when they are constrained away from the full potential of the wind, however, we considered that this was a relatively uncommon occurrence.

5 We define headroom as the difference between the generators current level of output and the maximum available in their offer.

6 We define floor space as the difference between the generators current level of output and the normal minimum level of generation above which the units operate. This is defined by either their minimum as defined in the AEMO NTNCP modelling dataset or, for fast start plant, the MW level for T2 in their FSIP.

Figure 1: Distributions of NSW minimum aggregate ramp rates



As can be seen from the red curve in Figure 1, our modelling suggests that the AEMC's preferred rule may result in higher aggregate minimum regional ramps in New South Wales for longer periods for ramp rates above 250 MW/5min (or 50 MW/min). This reflects improvements that would be gained under the preferred rule by requiring for example Snowy Hydro's Tumut 1800 MW aggregated generator to bid a ramp rate of at least 90 MW/5 min or 18 MW/min, compared to 3 MW/min currently..

Figure 2: Distributions of Victorian minimum aggregate ramp rates

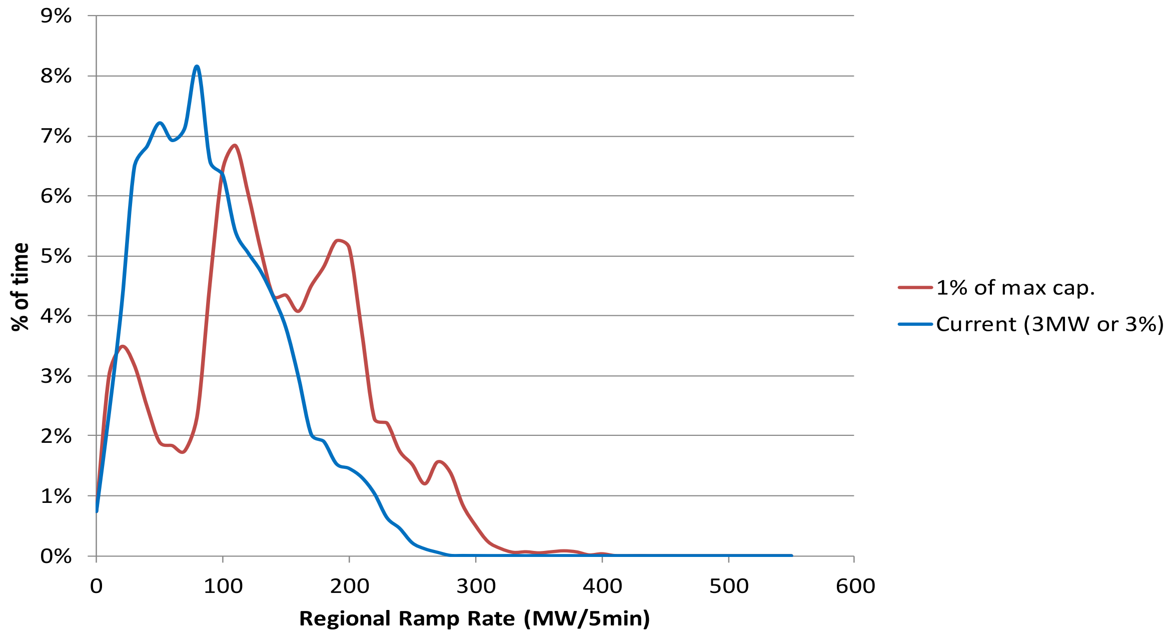
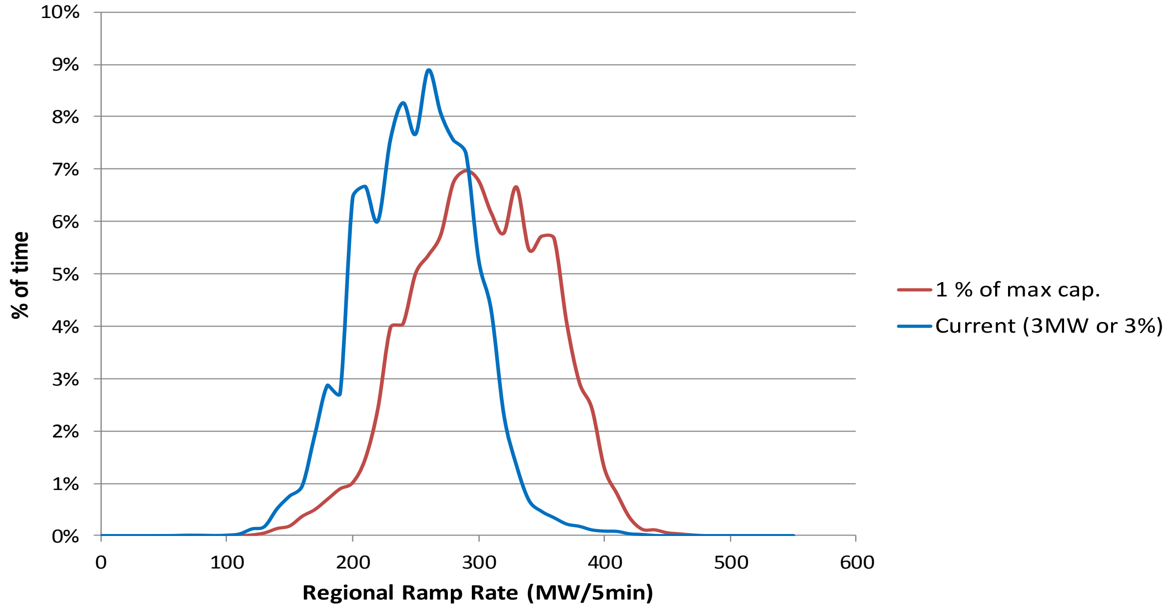


Figure 2 indicates that the result in Victoria would be similar to that in New South Wales. Our analysis suggests that in general, the AEMC's preferred rule may result in higher aggregate minimum regional ramps in Victoria for longer periods for ramp rates above approximately 100 MW/5min (or

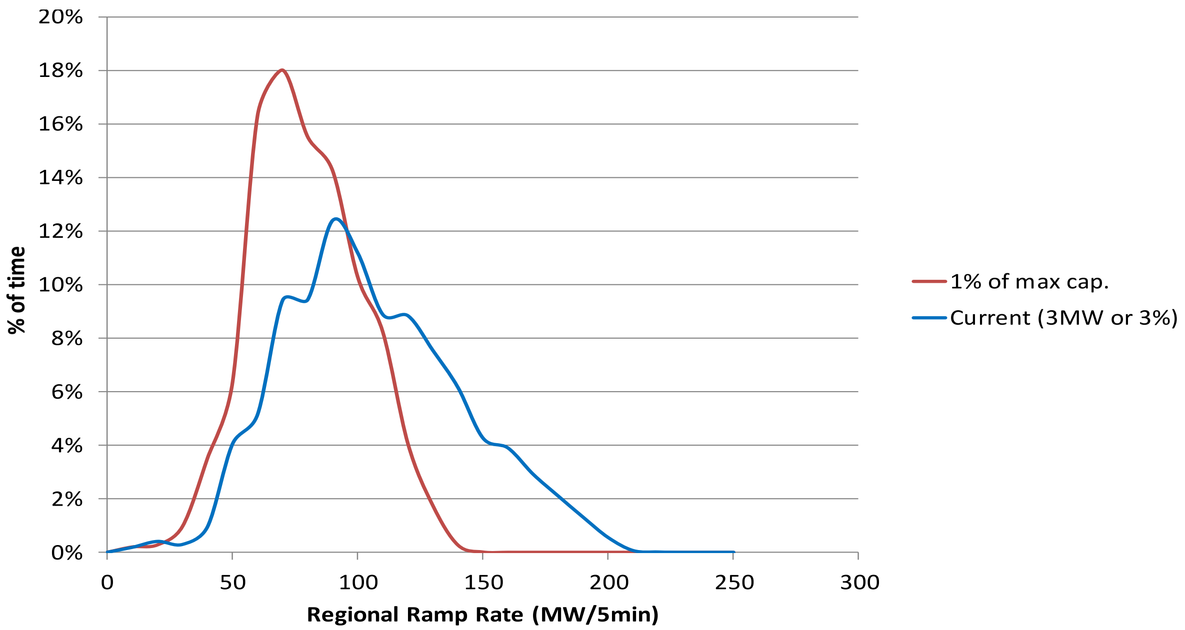
20 MW/min). Like for New South Wales, the improvement largely comes about through requiring Snowy Hydro's 1575 MW (maximum capacity according to schedule 3.1) aggregated Murray generator to bid a minimum allowable ramp rate of 80 MW/5 mins or 16 MW/min.

Figure 3: Distributions of Queensland minimum aggregate ramp rates



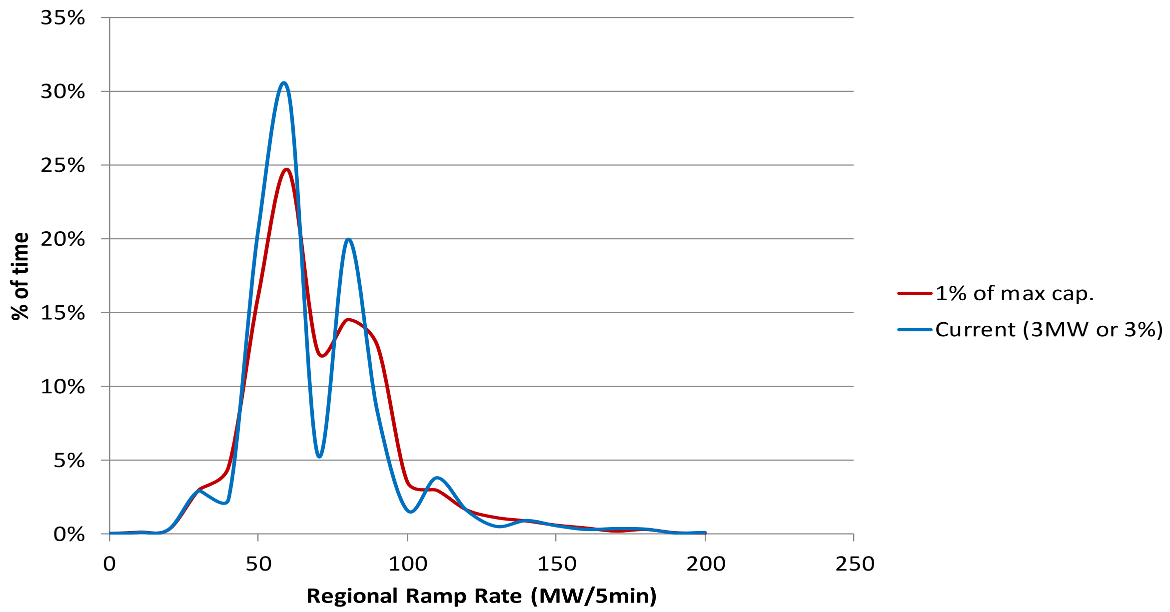
Our analysis suggests that in general, the AEMC's preferred rule may result in higher aggregate minimum regional ramp rates in Queensland for longer periods, for ramp rates above approximately 300 MW/5min (or 60 MW/min). The reason the curve shifts to the right in Queensland is that more minimum ramp rate would be available compared to the status quo from large thermal units including Origin Energy's Darling Downs, CS Energy's Stanwell and Wivenhoe units and Stanwell's Tarong units.

Figure 4: Distributions of Tasmanian minimum aggregate ramp rates



As shown in Figure 4, our analysis suggests that in general, the AEMC's preferred rule may result in more frequent lower aggregate minimum regional ramps in Tasmania for ramp rates below approximately 100 MW/5min (or 20 MW/min) and conversely, higher minimum aggregate ramp rates less frequently. Under the current rules, units under 100 MW are required to offer a minimum ramp of three per cent of registered capacity. With many units in Tasmania under 100 MW, applying the one per cent minimum ramp rate of maximum capacity would result in a reduction in minimum aggregate ramp rate available in Tasmania. This has the potential to contribute to greater price volatility in the Tasmania region as the reduced available minimum ramp rate may provide opportunities for the incumbent generators to rebid their ramp rates to even lower levels to manage higher price outcomes.

Figure 5: Distributions of South Australian minimum aggregate ramp rates



According to our analysis and as shown in Figure 5, the minimum aggregate ramp rate for South Australia under the AEMC's preferred rule follows a roughly similar distribution to the status quo. While there is a minor increase in the percentage of time that ramp rates between 30 and 40 MW/5mintues occur, this is more than offset by the reduction in the time that ramp rates between 50 and 70 MW/5minutes occur. South Australia has the largest penetration of wind generation relative to its demand of any region in the NEM. Wind generation can significantly reduce the commitment of conventional thermal generation in the region but can be highly variable. While system security may not be compromised, given the high level of installed wind capacity in South Australia, price volatility may prove more problematic under the preferred rule. Similarly the very rapid increase in demand associated with hot water load in the region (which occurs every night at midnight) may also lead to price spikes as higher priced capacity is dispatched in order to satisfy demand. This may lead to increased volatility in the region. Lack of ramp rate has caused six high price events in South Australia in the last twelve months, although higher numbers of events occurred in previous years. The AER anticipates that the adoption of the draft rule may increase the frequency at which these events occur.

2.3 Other Factors

2.3.1 System Security

Ultimately, AEMO can manage system security using directions and although the draft rule change increases the ramp rates available in some regions, this is not the case universally. In South Australia and Tasmania the draft rule change would appear to reduce the market's operational envelope and could foreseeably result in an increase in price volatility and the opportunity to manipulate outcomes by withdrawing ramp capability.

2.3.2 Commercial versus technical parameter

Several factors support the AER's assertion that ramp rates and FSIPs should reflect the technical capability of a plant. The high order priority of constraints associated with ramp rates and FSIPs used by the dispatch algorithm reflect their importance. Figure 1 in our rule change proposal shows the constraint violation penalty (CVP) for ramp rates is 1155, and for FSIPs is 1130, far in excess of satisfactory network limits (at 360) and secure network limits (at 35).

In its draft determination, the AEMC concluded that ramp rates and FSIPs are commercial parameters. Should this be the AEMC's final position, the priority order of the CVPs associated with these parameters may need to be re-examined.