Australian Energy Market Commission

# FINAL RULE DETERMINATION

## National Electricity Amendment (Generator ramp rates and dispatch inflexibility in bidding) Rule 2015

**Rule Proponent**

Australian Energy Regulator

19 March 2015

RULE CHANGE

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**About the AEMC**

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

## Summary of final rule determination

The Australian Energy Market Commission (AEMC or Commission) has made a rule to refine the existing requirements on generators to specify the minimum rates at which they may increase or decrease output.

This rule has been made following the Commission's consideration of a rule change proposed by the Australian Energy Regulator (AER), which would require that ramp rates reflect the maximum technical capability of generating plant. The AER has raised concerns that, at times, generators use ramp rates to achieve commercial outcomes that can lead to inefficiencies in the wholesale market and in the management of system security.

The Commission has not been convinced that a change as extensive as that proposed by the AER is warranted, and has concerns that the proposed rule might be difficult to apply in practice. However, in examining and consulting on the rule change request, the Commission has concluded that the existing provisions governing the minimum ramp rate requirements for aggregated generating units may distort competitive market outcomes and investment signals. The Commission has consequently made a more preferable rule that refines the current arrangements to address these issues.

**The Commission's final determination**

Generators may elect to combine individual physical generating units into a single aggregated generating unit for the purposes of the market dispatch process. The Commission's more preferable rule extends the current minimum ramp rate requirements to individual physical units that make up aggregated facilities.

The application of minimum ramp rate levels to individual physical units will result in an increase to the minimum ramp rate requirements for larger aggregated facilities, thereby bringing the requirements for aggregated units to a level more commensurate with those for individually registered units.

The revised requirements will result in an almost 30 per cent increase in aggregate minimum ramp rate capability across the NEM. This should increase the flexibility of the market dispatch process to determine more efficient wholesale market outcomes.

Minimum ramp rates will be applied consistently and proportionately to aggregated and non-aggregated facilities, which should promote more efficient generation investment in the long term interests of consumers.

**Commercial incentives as a driver of efficient investment**

The provision of system security requires that generators provide ramping capability to the market. Ramp rates are specified by generators as a component of their offers and govern the manner in which generation dispatch levels can be physically changed through time.

The Commission considers that commercial incentives are, and should be, the key driver for generators investing in, and maintaining, ramping capability. Flexible generating plant can best respond to price changes that signal alterations in the value the market places on the provision of energy. In this way, the commercial incentives acting on generators are aligned with the interests of consumers.

However, the presence of network congestion can result in a misalignment of these interests, and a commercial incentive can be created for generators to rebid their ramp rates to low levels. This may compromise the ability of the Australian Energy Market Operator (AEMO) to efficiently manage the security of the electricity system.

Therefore, under the current market design, there is a need to place a regulatory obligation on generators to provide a minimum level of ramping capability.

**The Commission's more preferable final rule**

The existing rules require that, for each registered generating unit, generators must specify a minimum ramp rate that is greater than or equal to the lower of three megawatts per minute (MW/minute), or three per cent of maximum capacity, unless there is a physical or safety limitation on their plant.

The Commission considers that under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units, and in particular is disproportionately borne by non-aggregated generators. The Commission considers that levels of aggregation are not an appropriate basis on which to determine ramp rate capability, and that the current rules have the potential to inhibit AEMO's ability to optimise the dispatch process.

The Commission's more preferable rule extends the current minimum ramp rate requirements to individual physical units that make up aggregated facilities. By effectively applying minimum ramp rate requirements to individual physical units that make up aggregated generators, the burden of system ramp rate capability will no longer be disproportionately borne by non-aggregated generators. Treating aggregated and non-aggregated facilities on the same basis promotes technology neutrality and therefore the efficient operation of electricity services when generators are required to reduce output through the market dispatch process. Such competitively neutral arrangements promote more efficient wholesale market outcomes and allow AEMO to maintain the secure operation of the electricity system.

In addition, rules that are applied consistently and proportionately to generators should ensure that the regulatory framework does not inadvertently influence investment decisions in favour of aggregated units. Investment based purely on commercial considerations can be expected to result in the provision of more efficient supply, in the long term interests of consumers.

The Commission has assessed the impact of this change on the market and, based on advice received from AEMO, is satisfied the more preferable final rule would maintain or enhance AEMO's ability to manage the secure operation of the electricity system.

**The Commission's assessment of the AER's proposed rule**

The Commission recognises the importance of the issues raised in the rule change request, but has not been convinced that a change as significant as that proposed by the AER is warranted. In particular, information provided by AEMO indicates that such an extensive increase in minimum required ramp rates is not necessary in order to efficiently manage system security.

The AER also raised concerns regarding other potential market outcomes, including the occurrence of counter-price flows between regions, productive efficiency losses from high cost plant being dispatched in place of low cost plant, and higher risk management costs due to higher wholesale price volatility. To the extent that these represent market inefficiencies, the Commission considers that it would be desirable to minimise their impacts. However, the Commission notes that, in most cases, ramp rates represent only one contributing factor. To seek to resolve these issues by requiring generators to always offer the maximum technical capability of their plant also risks creating a disincentive to invest in flexible plant, as the burden of system ramp rate capability may be disproportionately shifted to more flexible generators.

Finally, the Commission is concerned that the proposed rule would have been difficult to apply in practice. The Commission's view is that a trade-off exists between ramp rate capability and costs incurred, and this would make it problematic for the AER to determine whether the ramp rates submitted by generators represent a true reflection of the technical capability of their generating units at any given time.

The Commission's more preferable final rule is a different more preferable rule to the one that was set out in the draft determination. The more preferable final rule improves the consistency and proportionality in the application of the minimum ramp rate requirements in comparison to the current rules while avoiding the practical implementation issues that were raised in response to the draft determination.

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# 1 The Australian Energy Regulator's rule change request

## 1.1 The rule change request

On 21 August 2013, the Australian Energy Regulator (AER) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) proposing a requirement that ramp rates and dispatch inflexibility profiles for generators in the National Electricity Market (NEM) should reflect their technical capabilities.

Ramp rates and dispatch inflexibility profiles are specified by generators as a component of their offers and govern the manner in which the generation output from power stations can be physically changed through time.

This rule change request is intended to address purported inefficiencies resulting from the incentives generators have to change their ramp rates to low levels at times when the capacity of the transmission network is constrained. The AER proposes this can be achieved by requiring generators to at all times specify the maximum technical ramp rate that their generating plant can safely achieve.

The AER also notes that dispatch inflexibility profiles can be used by participants with fast-start plant to achieve commercial objectives and that this can also result in market inefficiencies.[1] The AER considers this issue can be addressed by requiring fast-start generators to submit dispatch inflexibility profiles that reflect the technical capabilities of their plant at the time.

## 1.2 Current arrangements

Clause 3.8.3A of the National Electricity Rules (NER) currently requires all scheduled generators, semi-scheduled generators or market participants with generating units, scheduled network services and/or scheduled loads that provide ramp rates to the Australian Energy Market Operator (AEMO) to specify an up ramp rate and a down ramp rate for each 30-minute trading interval. Ramp rates can be changed (rebid) at any time during a trading interval with effect from the next 5-minute dispatch interval.

These participants must specify a ramp rate that is greater than or equal to the lower of three megawatts per minute (MW/minute), or three per cent of maximum capacity, unless there is a technical limitation on their plant at the time.

Clause 3.8.19(d) of the NER currently provides fast-start generators with the discretion to include a dispatch inflexibility profile as part of its dispatch offer. Dispatch inflexibility profiles are used by fast-start plant such as gas turbines, to inform the

1 Dispatch inflexibility profiles do not apply to slow start generating units. Slow start generating units are defined in clause 3.8.17 of the NER as units which are unable to synchronise and increase generation within 30 minutes of receiving an instruction from AEMO.

dispatch process of inflexibilities in respect of their units such as minimum start and stop times, and minimum safe operating levels.

**Appendix B** provides further detail on ramp rates and dispatch inflexibility profiles in the NEM.

## 1.3 Rationale for the rule change request

The physical power system comprises a network of transmission lines that convey electricity from generating plant to customer load centres. The capacity ratings of these network lines place limits on the transmission of electricity and may impact the extent to which electricity can be sourced from generators with the lowest offers. As such, generators have uncertain access to the market, in terms of their ability to be dispatched and receive the regional energy price. There is currently no mechanism that allows generators to hedge this risk. Instead, generators may attempt to reduce the risk of being constrained by varying their offers.

The AER's rule change request seeks to reduce the ability of generators to pursue commercial objectives at times of network congestion through the rebidding of ramp rates and changes to dispatch inflexibility profiles. In particular, the AER is seeking to address instances where generators that are likely to be constrained off may rebid to reduce their ramp rates or make changes to their dispatch inflexibility profiles to limit the extent to which their existing output levels can be decreased.

The AER considers that generator rebidding at times of network constraints has become increasingly prevalent[2] and that the previous change made to the NER in 2009 has not been sufficient to address market inefficiencies.[3] The AER maintains that the use of ramp rates and dispatch inflexibility profiles 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 economically optimal fashion.

## 1.4 Solution proposed in the Rule Change Request

The AER is seeking to place a greater restriction on the ability of generators to vary ramp rates and dispatch inflexibility profiles by requiring generators to always submit parameters that reflect the maximum technical operating capability of the plant at that time.

The ramp rate provided to AEMO would be the maximum the generator can safely attain. If, closer to the time of dispatch, a generator submits a ramp rate that is materially different from its previous technical maximum, then it would be required to accompany the rebid with a brief, verifiable, and specific reason relating to the relevant technical limitation on their generating plant.

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2 AER, *Special report – The impact of congestion on bidding and inter-regional trade in the NEM*, December 2012, p. 21.

With respect to dispatch inflexibility profiles, the AER considers that the current rules are imprecise and that generators can change this parameter through the rebidding process for any reason, and may do so for commercial advantage. The AER is therefore seeking to require fast-start generators to submit a dispatch inflexibility profile that always reflects the technical limitations of their plant.

The AER proposes to align all of the rules related to ramp rates and dispatch inflexibility profiles to ensure they reflect the technical characteristics of plant and cannot be manipulated for short-term commercial gain. The AER states that this would align the treatment of ramp rates and dispatch inflexibility profiles with the current treatment of other technical parameters in the NER, such as frequency control ancillary services parameters, which must reflect the technical capabilities of the plant.

The rule change would apply to all participants required to submit ramp rates to AEMO, including scheduled and semi-scheduled generators, scheduled network services and scheduled loads.

To provide further clarity on how the proposed rule would operate in practice, and how the AER would enforce it, the AER has stated that it would amend its Rebidding and Technical Parameters Guideline.[4]

## 1.5 The Commission's rule making process

On 13 February 2014, the Commission published the AER's rule change request and a paper identifying specific issues and questions for consultation. The Commission also published a notice extending the timeframe for the publication of its draft determination to 28 August 2014. This extension of time was to allow for the analysis necessary to address the complex issues raised in the rule change request.

The Commission held a public forum on 5 May 2014 to provide an opportunity for stakeholders to share their views on the scope of the issues identified in the rule change request, the impact of the proposed rule, and any alternative solutions that may better address the identified problems. A copy of the presentations given at the public forum can be found on the AEMC website.

On 28 August 2014, the Commission made a draft determination to make a more preferable draft rule following its consideration of the AER's rule change request. This reflected the Commission's view that a change as extensive as that proposed by the AER might not be warranted, and its concerns that the proposed rule might be difficult to apply in practice. However, in examining and consulting on the rule change request, the Commission concluded that the existing provisions governing ramp rates may distort competitive market outcomes and investment signals. The Commission's more

3 AEMC, *Ramp rates, market ancillary service offers, and dispatch inflexibility – final determination*, 15 January 2009.

4 The AER may amend or replace the guideline from time to time in accordance with clauses 3.8.3A(g), 3.8.19(b)(2) and 3.8.22(c)(3) of the NER.

preferable draft rule therefore sought to refine the current arrangements to address this issue.

The Commission received 14 submissions in response to the draft rule determination. A summary of the issues raised in submissions and the Commission's response to each issue is contained in **Appendix C**.

Submissions were generally supportive of the Commission's more preferable draft rule in principle. However, some stakeholders provided evidence that compliance at all times with the more preferable draft rule may not be practicable for specific generators.

On 20 November 2014, the AEMC extended the period of time for publication of the final rule determination to 19 March 2015. The Commission considered the extension necessary in light of the complex issues raised in submissions to the draft rule determination, particularly its potential impact on large thermal generating units. The new information received in submissions represented a material change in circumstances, and it was appropriate to allow for additional time to fully consider the issues and consult further with stakeholders.

On 18 December 2014, the AEMC published an options paper seeking stakeholders' comments on two further options that would address the issues raised in submissions to the draft determination in relation to the implementation of the more preferable draft rule. The additional options were designed such that they would still better meet the Commission's objectives for ramp rate requirements that can be applied more consistently and proportionately than the current rules.

The period for submissions on the options closed on 5 February 2015. The Commission received 11 submissions, which are available on the AEMC website.[5] A summary of the issues raised in submissions and the Commission's response to each issue is contained in **Appendix D**.

In making this final determination, the Commission has assessed these options alongside the proposed rule, and against the possibility of not making a rule.

5 www.aemc.gov.au

# 2 Final Rule Determination

The Commission has decided to make a more preferable final rule to extend the current minimum ramp rate requirements to each of the individual physical units that make up aggregated facilities. The current rules would therefore be applied consistently to aggregated and non-aggregated generators, scheduled loads and scheduled network services.

The Commission has concerns that the AER's proposed rule, to require generators to provide their maximum technical ramp rate at all times, may create a disincentive to invest in or to operate generating plant with more flexible ramp rate capability. Further, the Commission considers that, as the ramp rate capability of generating plant is not constant, and requires that trade-offs be made between capabilities and costs, the AER's proposed rule may be difficult to apply in practice.

This Chapter outlines:

- the Commission's rule making test for changes to the NER;
- the Commission's assessment framework for considering the rule change request; and
- a summary of the Commission's final determination, including the reasoning for its decision.

**Appendix A** sets out further detail regarding the legal requirements for the making of this final determination.

## 2.1 Rule making test

The Commission may only make a change to the NER if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO).[6]

The NEO states:[7]

> "The objective of this Law is 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; and
>
> (b) the reliability, safety and security of the national electricity system.""

6 See section 88 of the NEL.

7 See section 7 of the NEL.

The Commission can make a rule that is different from the proposed rule if it is satisfied that, having regard to the relevant issues in the rule change request, the more preferable rule will or is likely to better contribute to the NEO.[8]

## 2.2 Assessment framework

The promotion of efficiency lies at the heart of the NEO, and the Commission considers that, where feasible, the use of competitive markets provides the best means of achieving this. This approach is most effective where the commercial incentives acting on generators are aligned with the long term interests of consumers.

In the NEM, prices generally signal to generators to either increase or decrease supply depending on whether this is valued by consumers, providing efficient market outcomes. However, this rule change request seeks to address concerns that the commercial incentives acting on generators in the NEM may not be aligned with the interests of consumers in all circumstances and can, on occasion, lead to outcomes which are not efficient with regard to the price or the reliability and security of supply of electricity.

The Commission considers that the impact on commercial incentives can be minimised if minimum ramp rate requirements are:

- applied consistently for all participants;
- distributed proportionately such that the burden of system ramp rate capability is shared across all participants and not borne by generating units of a particular size or technology;
- easily determined, unambiguous, and not subject to significant variation; and
- able to be applied easily in practice to minimise compliance costs.

Rules that are designed to meet these objectives should ensure that the minimum level of required ramp rate capability is provided at the lowest cost in the long term interests of consumers.

For this rule change request, the Commission considers the relevant aspects of the NEO to be the efficient operation of electricity services and the efficient investment in electricity services.

The efficient operation of electricity services, or productive efficiency, can be attained when dispatch is optimised such that the production of electricity occurs at the lowest cost. Productive efficiency can be promoted by rewarding those generators who are able to vary output in response to changes in supply and demand at the lowest cost.[9]

8 See section 91A of the NEL.

9 In the NEM, the market dispatch process attempts to maximise the efficiency of market outcomes by dispatching the lowest priced offers first. However, generators' offers may not always be representative of their short-term costs. As such, a market dispatch arrangement in strict

Efficient investment in electricity services, or dynamic efficiency, is promoted when productive (and allocative) efficiency occurs over time.

In assessing this rule change request, the Commission has had to consider its likely effects in terms of both forms of efficiency. While the proponent has highlighted its concerns regarding productive efficiency, the Commission has to weigh this against any effects on dynamic efficiency, given the role of commercial incentives in driving efficient investment.

The Commission is also conscious that rules that seek to impose minimum requirements on generators in the interests of system security have the potential to diminish both productive efficiency and dynamic efficiency. Rules that are applied inconsistently may reduce productive efficiency if the dispatch process cannot be fully optimised. They may also reduce dynamic efficiency if the preferential treatment of certain types of participants impacts on investment decisions.

The Commission has considered the following matters in assessing whether making a change to the existing arrangements will, or is likely to, promote the NEO, in particular the maintenance of the security and reliability of the electricity system:

- the optimisation of the dispatch process such that the production of electricity occurs through the most efficient means;
- consistency of application in the rules such that investment decisions are not unduly influenced by arbitrary factors and are based purely on commercial and economic considerations; and
- the impact on investments in new generation technology such that demand is able to be met over time through the most efficient options.

## 2.3 The Commission's final rule determination

The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many generators, flexibility is necessary to provide energy to the market at times of highest value. Generators have an incentive to increase generation quickly when the spot price is high and reduce generation when the spot price falls below their operating costs. Generators may also have an incentive to maintain flexibility to support variations in their contract positions. Rules that attempt to prescribe fixed requirements on ramp rate capability have the potential to disrupt the efficient functioning of the market incentive framework.

However, the Commission recognises that the presence of network congestion can, at times, create a commercial incentive for generators to rebid their ramp rates to low levels, which can compromise the ability of AEMO to efficiently manage the stability and security of the electricity system. Therefore, the Commission considers that the

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accordance with the ranking of price and volume offers does not necessarily imply that productive efficiency is maximised.

rules should require participants to provide a minimum level of ramp rate capability at all times, consistent with AEMO's ability to provide this system security.

The Commission considers that, while the AER's proposed rule would provide more than the required minimum level of ramp rate capability to manage the secure operation of the electricity system, it may also create a disincentive to invest in flexible plant by disproportionately impacting generators that are able to provide greater ramp rate capability. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes in the long term interests of consumers.

However, while not supporting the AER's proposed rule, the Commission also has concerns in relation to the current arrangements. While the current minimum ramp rate requirements provide sufficient capability for AEMO to manage the secure operation of the electricity system, the Commission considers that the existing rules may prevent this from being achieved through the most efficient means.

In determining the minimum required ramp rates to satisfy the efficient management of system security, the Commission considers that the efficiency of wholesale price outcomes will be influenced by the extent to which the commercial incentives for ramp rate capability are preserved.

The Commission considers that under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units, and is disproportionately borne by non-aggregated generators. In its view, the level of aggregation of generating units is not an appropriate basis on which to determine ramp rate capability, and that the current rules have the potential to inhibit AEMO's ability to optimise the dispatch process.

The Commission is satisfied that the more preferable final rule to apply the current minimum ramp rate requirements to individual physical units that make up aggregated facilities will, or is likely to, contribute to the achievement of the NEO for the following reasons:

- Promoting the efficient operation of electricity services by treating aggregated and non-aggregated generators on the same basis when they are required to change output through the market dispatch process. This should increase the aggregate minimum level of ramp rate capability in the market and thereby promote the ability of AEMO to optimise the NEM dispatch process more efficiently, which will enhance the efficient operation of electricity services for the long term interests of consumers.

- Promoting the NER principle of technology neutrality by applying a consistent set of rules to aggregated and non-aggregated participants.[10] This will ensure

10 In this context, technology neutrality means that, to the greatest extent possible, the NER should not advantage one technology type over another. As set out in section 3.1.4(3) of the NER, one of the market design principles of the NEM includes "the avoidance of any special treatment in respect of different technologies used by market participants".

that investment decisions are based on commercial drivers as signalled by the market and would remove favourable minimum ramp rate requirements from the decision of whether or not to aggregate units. This should promote efficient outcomes in the long term interests of consumers.

Further information on the Commission's consideration of the issues raised in the rule change request and the AER's proposed rule is set out in Chapter 3. The Commission's reasons for its more preferable final rule are provided in Chapter 4.

## 2.4 Commencement of the final rule

The final rule will commence on 1 July 2016. This date has been selected to provide sufficient time for AEMO's systems and procedures to be updated and for participants to adjust to the new minimum ramp rate requirements.

## 2.5 Strategic priority

Costs for consumers are likely to be minimised where market arrangements encourage efficient investment. This is the basis for the AEMC's third strategic priority for energy market development (the Market Priority). The strategic priorities underpin the Commission's work, helping to guide our advice to governments and our approach to rule making.

The more preferable final rule contributes to the Market Priority by ensuring that investment decisions made regarding the aggregation of units are not influenced by the regulatory framework around the calculation of minimum ramp rates. This would ensure that, to the greatest extent possible, investors make decisions based on economic and commercial factors, which would promote the efficient operation of the market and contribute to efficient outcomes that minimise costs for consumers.

# 3 Issues raised in the rule change request and the AER's proposed rule

The AER has stated that there are a range of costs associated with the rebidding of ramp rates and changes to dispatch inflexibility profiles under constraint conditions to achieve commercial objectives.

The Commission has noted that the nature of these costs can change depending on whether rebidding is undertaken through ramp rates and changes to dispatch inflexibility profiles, or through other forms including variations to price and volume. In the context of generator rebidding, the Commission has categorised the costs raised by the AER into those where the rebidding of ramp rates and changes to dispatch inflexibility profiles may be directly attributed and those where it may be a contributing or supporting factor but not necessarily the principal or underlying cause.

This Chapter outlines the Commission's considerations of the issues raised in the rule change request and its assessment of the AER's proposed rule.

## 3.1 System security and counter-price flows

This section sets out the Commission's considerations of the issues raised by the AER that, in the context of generator rebidding, may be directly attributed to the rebidding of ramp rates and changes to dispatch inflexibility profiles, including the efficient management of system security and counter-price flows between NEM regions.

### 3.1.1 The AER's view

The AER considers that the ability of generators to rebid ramp rates and make changes to dispatch inflexibility profiles under constraint conditions to achieve commercial objectives may:

- compromise the ability of AEMO to determine an economically efficient dispatch arrangement while maintaining system security;[11] and
- reduce the effectiveness of interconnectors and increase network charges to consumers by causing counter-price flows between NEM regions.[12]

The AER considers that these outcomes are primarily driven by the priority afforded to ramp rates and dispatch inflexibility profiles when the optimal economic dispatch is calculated by the National Electricity Market Dispatch Engine (NEMDE).

In order to manage network congestion, NEMDE prioritises different technical aspects of generators and the network. Ramp rates and dispatch inflexibility profiles are

11 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, p. 18.

12 Ibid, pp. 7-9.

considered to be the highest priority constraint types. This is because ramp rates can vary across a wide range and AEMO is not in a position to make assumptions about the capabilities of individual generators. As such, AEMO is dependent on what generators submit.

In order to determine the optimal dispatch arrangement, NEMDE must take into consideration the limitations imposed by different physical parameters of generators and the network. Some parameters are more flexible than others and NEMDE prioritises different parameters to manage network congestion.

Each physical parameter is assigned a constraint violation penalty (CVP) which represents a notional incremental cost incurred if a constraint equation that represents the parameter is violated.[13] To determine a feasible solution in a constrained condition, NEMDE allows constraint equations to be violated. NEMDE allows constraints with the lowest CVP to be violated first.

Table 3.1 shows CVPs for a number of different physical parameters. Satisfactory and secure network limits and the management of negative residues (clamping) have lower CVPs than ramp rates and dispatch inflexibility profiles. As such, a generator that rebids its ramp rates to low levels in order to maintain generation output under constraint conditions will be prioritised in the dispatch process over network limits and the management of negative residues.[14] This means that when generators rebid ramp rates to low levels or make changes to their dispatch inflexibility profiles, the effect may be to compromise the efficient management of system security or to potentially give rise to counter-price flows between NEM regions.

**Table 3.1 Constraint violation penalties**

| | CVP |
|---|---|
| Ramp rates | 1155 |
| Dispatch inflexibility profiles | 1130 |
| Minimum and fixed loading level | 380 |
| Satisfactory network limit | 360 |
| Secure network limit | 35 |
| Negative residue management (clamping) | 2 |

Importantly, NEMDE will give priority to network limits over generator offers of price and volume but not over ramp rates and dispatch inflexibility profiles. Therefore, a

13 Ibid, p. 10.

14 AEMO uses reasonable endeavours to manage the accumulation of negative inter-regional settlement residues when the accumulation reaches $100,000. This is achieved by invoking constraints on the interconnector to "clamp" the flow of electricity from the high-price region to the low-price region.

potential distinction exists between the impact that ramp rates have on the ability for AEMO to manage system security compared to the impact of price and volume offers.

AEMO may step in to override generator offers by directing generators to change output in the interests of system security. However, directions to generators by AEMO are made irrespective of economic considerations and NEMDE's calculation of the optimal economic dispatch. Therefore, while AEMO always has the ability to provide directions to generators in an effort to maintain system security, generators reducing ramp rates under constraint conditions may compromise the ability for AEMO to determine an economically efficient dispatch arrangement while maintaining system security.

Similar to the management of system security, counter-price flows may also occur from generators engaging in other forms of rebidding under constraint conditions, such as the rebidding of price and volume. However, the costs associated with the rebidding of ramp rates have the potential to be more substantial. As with the management of system security, AEMO will override generator offers, including rebidding capacity into negative price bands, in order to limit counter-price flows but will ensure the management of generator ramp rates and dispatch inflexibility profiles takes precedence.

Counter-price flows lead to the accumulation of negative inter-regional settlement residues as retailers pay the low spot price in the importing region and generators receive the high spot price in the exporting region. This shortfall in spot market settlements is recovered from customers in the low-price region through network tariffs in the form of transmission use of system (TUOS) fees.

In its rule change request the AER cited a number of occasions where it considers that generator bidding at times of network constraints has resulted in significant counter-price flows between NEM regions.[15]

### 3.1.2 Stakeholder submissions

In its submission on the consultation paper, AEMO confirmed that ramp rates are the highest priority constraint and that generator rebidding ramp rates as a means of maintaining high generation output would override network constraints. However, AEMO also confirmed that the current minimum ramp rate requirements continue to be sufficient to manage the NEM power system under normal circumstances.[16]

A number of participants noted that AEMO's powers to override generator offers by issuing directions to market participants constitute an additional tool that can be used to manage power system security and stability.[17] Snowy Hydro noted that AEMO has

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15 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, p. 8.

16 AEMO, submission on the consultation paper, p. 5.

17 See submissions on the consultation paper from: Origin Energy, p. 4; NGF, p. 3; Snowy Hydro, p. 6.

not used its power of direction to source more ramping capability to meet system security since the current minimum requirements were included in the NER in 2009.[18]

A number of stakeholders considered that counter-price flows undermine the efficient operation of the market and that a reduction in counter-price flows would improve efficient dispatch and price discovery.[19]

Snowy Hydro and the National Generators Forum (NGF) contended that counter-price flow events have predominantly occurred at times of multiple non-credible transmission outages, which has acted to significantly reduce the capability of the transmission network.[20] Snowy Hydro suggested that, of the total negative settlement residues noted by the AER in their rule change request,[21] the majority occurred at times of multiple and non-credible transmission outages, equivalent to 97 per cent on the Victoria to New South Wales interconnector and 91 per cent on the New South Wales to Victoria interconnector.[22] It suggested that, because generators have no control over this risk, it is at these times that generators must manage their exposure through the bidding process, which may inevitably result in the occurrence of counter-price flows between NEM regions.

In a report prepared by ACIL Allen, which accompanied Snowy Hydro's submission on the consultation paper, it was argued that generators rebidding ramp rates to low levels at times of network congestion is a rational response to the absence of compensation for being constrained off.[23] The report contended that it is this lack of compensation rather than the response that should be addressed.

A number of participants further contended that the materiality of the issue has been overstated by the AER as a significant proportion of the total negative residues attributed to generator rebidding activities in the rule change request were accumulated in a few market events that were isolated in nature and are unlikely to be repeated again.[24]

### 3.1.3 The Commission's assessment

The Commission agrees with the AER's view that, due to the occurrence of network congestion in the NEM, a minimum ramp rate capability must be provided by generators at all times in order to ensure the efficient management of system security.

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18 Snowy Hydro, submission on the consultation paper, p. 6.

19 See submissions on the consultation paper from: Alinta Energy, p. 3; Government of South Australia, p. 1.

20 See submissions on the consultation paper from: Snowy Hydro, p. 8; NGF, p. 4.

21 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, pp. 22-25.

22 Snowy Hydro, submission on the consultation paper, p. 8.

23 ACIL Allen Consulting, *Review of aspects of AER's rule change proposal*, report to Snowy Hydro, 27 March 2014, p. 3.

24 See submissions on the consultation paper from: Origin Energy, pp. 2-3; NGF, p. 4.

The Commission notes that the minimum required ramp rate of 3 MW/minute was considered to be sufficient to manage the NEM power system under normal circumstances at the time of the previous rule determination in 2009, and that AEMO confirmed that this continues to be the case.

While AEMO maintains the power to direct generators to change output in the interests of system security, the Commission is satisfied that such an occurrence is unlikely to occur under normal circumstances given the existing minimum requirements of 3 MW/minute. Indeed, the Commission notes that AEMO has never been required to direct a generator to change output due to the rebidding of ramp rates since the minimum requirement of 3 MW/minute was first enforced in 2009.

Therefore, the Commission does not support the AER's view that the current minimum ramp rate requirement of 3 MW/minute is insufficient in the current circumstances and that it is likely to compromise the ability of AEMO to efficiently manage the secure operation of the electricity system. In many instances commercial incentives drive generators to submit ramp rates higher than the minimum.

With regard to counter-price flows, the Commission has noted the considerable divergence of views in submissions regarding the causes and materiality of the issue.

While acknowledging the AER’s concerns in relation to inefficient outcomes caused by the occurrence of counter-price flows, the Commission considers that there has been no compelling evidence produced to date that suggests that the costs to the market are likely to be material in the context of the NEM as a whole.

Further, the Commission recognises that there are a range of factors that can create the conditions in the market that give rise to counter-price flows. These conditions may include generators rebidding ramp rates or changing dispatch inflexibility profiles, but may also include other factors unrelated to generator rebidding that impact the capability of the network, such as the timing of network outages. The Commission notes the suggestions that, in a number of market events where substantial negative residues have been accrued, multiple network outages occurred simultaneously that may have had a significant bearing on the extent of counter-price flows.

Therefore, the Commission has not been persuaded that it would be appropriate to make a rule that requires generators to provide a greater minimum level of ramp rate capability that does not also address the range of other factors that may contribute to counter-price flows.

## 3.2 Productive efficiency losses and risk management costs

This section sets out the Commission's considerations of the issues raised by the AER where the rebidding of ramp rates and changes to dispatch inflexibility profiles may be a contributing or supporting factor but for which other forms of generator rebidding may also be a cause. These issues include productive efficiency losses and higher risk management costs.

### 3.2.1 The AER's view

The AER considers that generators that engage in rebidding at times of network constraints may create productive inefficiencies by causing high cost plant to be dispatched in place of low cost plant.[25] This may occur not just through rebidding of ramp rates and dispatch inflexibility profiles but also through other forms of rebidding, such as the rebidding of generation capacity between price bands.

Based on generator offers received, NEMDE determines the production levels of plant to meet demand given the limitations placed by congestion in the network. Generators may change their offers to influence the outcomes that NEMDE chooses to determine the production levels of plant. The AER considers that generator rebidding under constraint conditions changes the merit order of dispatched plant and may result in high cost generation being dispatched in place of low cost generation, thereby resulting in productive efficiency losses. The AER did not provide any specific estimates of the materiality of these losses as part of its rule change request.

In addition, the AER considers that instances of rebidding of price and volume at times of network constraints can result in higher wholesale spot price volatility and reduce spot price predictability, and that the rebidding of ramp rates by generators at the same time can exacerbate the problem.[26]

The AER suggests that the higher price volatility is primarily caused by generators that are constrained off rebidding capacity into negative price bands in an effort to maintain generation output. While the price is initially set on the opposite side of the constraint by higher priced generation, the volatility is caused by the constrained off generator setting the price at negative levels when the constraint ceases to bind. The market may then revert to a higher price when the constraint binds again. As a consequence, spot prices may fluctuate between levels close to the price cap and levels close to the price floor over successive five-minute dispatch intervals. The AER considers that the rebidding of ramp rates prolongs the effect by allowing the constrained off generator to further reduce the rate at which its dispatch levels are decreased.

Increased spot price volatility leads to an expectation of similar volatility in the future, which can lead to an increase in the risk premium on hedge contracts.[27] The higher risk profile may then flow through to consumers in the form of higher energy charges.

### 3.2.2 Stakeholder submissions

Snowy Hydro suggested that dispatch inefficiency caused by generators rebidding at time of network constraints is immaterial in total and with respect to the overall size of the NEM.[28] Snowy Hydro cited two separately commissioned studies that have

25 AER, *Request for rule change - Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, p. 22.

26 Ibid, p. 14.

27 Ibid, pp. 18-19.

28 Snowy Hydro, submission on the consultation paper, p. 7.

attempted to estimate the total productive inefficiency at between $8 million and $10 million per annum. Further, Snowy Hydro contended that these estimates were based on all forms of generator bidding under constraint conditions and that generators rebidding ramp rates may only be responsible for a fraction of this.

The report prepared by ACIL Allen for Snowy Hydro contended that generator bidding in response to transmission congestion is not necessarily non-cost reflective.[29] Generator dispatch offers are opportunity cost reflective in that they take into account system and market conditions, including transmission constraints, and can be interpreted as the prices at which the generator is indifferent about having the relevant dispatch quantities dispatched or not.

The NGF contended that the focus on productive efficiency is misguided as generators' contract positions dictate their activities in the physical market.[30] As such, while the physical dispatch in the NEM on a day to day basis may not be productively efficient, the competitive process should result in efficient price outcomes in the long-term.

In relation to higher risk management costs, Snowy Hydro suggested that the extent to which higher risk premiums on hedge contracts are attributed to the use of ramp rates is difficult to discern from the impact of other forms of rebidding and is likely impossible to quantify.[31] Arrow Energy also noted that rebidding ramp rates should not be isolated as the sole issue causing inefficient price signals.[32] Alinta Energy considered that, in assessing effects on price volatility, the focus would need to be on the level of volatility above that which is reflective of the true underlying conditions of supply and demand.[33]

### 3.2.3 The Commission's assessment

The AER's view that generators rebidding ramp rates under constraint conditions leads to productive efficiency losses appears predicated on an assumption that a generator's offers are representative of their operational costs. However, the Commission considers that a generator's offers may also take into account a range of other factors, such as the opportunity costs of not being dispatched. As such, the rebidding of ramp rates by generators that inhibits a market dispatch arrangement in strict accordance with the ranking of price and volume offers does not necessarily imply a productive efficiency loss.

Further, the AER's view does not take into account the costs to generators that are implicit to the provision of ramp rate capability. An increase in operating and

29 ACIL Allen Consulting, *Review of aspects of AER's rule change proposal*, report to Snowy Hydro, 27 March 2014, p. 9.

30 NGF, submission on the consultation paper, pp. 6-7.

31 Snowy Hydro, submission on the consultation paper, p. 10.

32 Arrow Energy, submission on the consultation paper, p. 4.

33 Alinta Energy, submission on the consultation paper, p. 3.

maintenance costs to generators from providing higher ramp rates should be considered alongside any potential gains in productive efficiency.

The Commission acknowledges the results of earlier studies undertaken to estimate the extent of productive efficiency losses arising from generator rebidding activities, which suggests these are likely to be small relative to total market turnover.[34] These estimates were undertaken to assess the impact of all forms of generator rebidding at times of network constraints, and the rebidding of ramp rates is only likely to represent a portion of the overall estimate.

The Commission also recognises that the difficulty in discerning the impact of the rebidding of ramp rates from other forms of rebidding extends to the impact on price volatility and the possible consequent increase in risk premiums on forward hedge contracts. This is particularly the case given that higher price volatility is primarily caused by the rebidding of volume between price bands but that the rebidding of ramp rates prolongs the effect by allowing the generator to reduce the rate at which it is constrained off.

Similar to counter-price flows discussed in section 3.1.1, the Commission has not been persuaded that it would be appropriate to make a rule that requires generators to provide a greater minimum level of ramp rate capability that does not also address the range of other factors that may contribute to these outcomes.

## 3.3 The AER's proposed rule

This section sets out the Commission's considerations on the AER's proposed rule.

### 3.3.1 Summary of the proposed rule

The AER's proposed rule would require generators to always submit ramp rates that reflect their technical capability at the time.

The ramp rate provided to AEMO would be the maximum the generator can safely attain. If, closer to the time of dispatch, a generator submits a ramp rate that is materially different from its previous technical maximum, then it would be required to accompany the rebid with a brief, verifiable, and specific reason relating to the relevant technical limitation on their generating plant.

The AER's proposed rule would also place a greater restriction on dispatch inflexibility profiles by requiring fast start generators to submit a dispatch inflexibility profile that reflects the technical limitations of their plant.

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34 In 2013, ROAM Consulting estimated these costs to range from $3 million to $15 million for the three year period from 2010 to 2012 (See: ROAM Consulting, Modelling Transmission Frameworks Review, 28 February 2013). In 2008, Frontier Economics estimated these costs to be approximately $8 million for the financial year 2007/08 (See: AEMC, Congestion Management Review, Final Report, June 2008, p. 33).

Given the variable nature of ramp rates, the AER proposes to provide further clarity on how the proposed rule would operate in practice, and how the AER would enforce it, through amendments to the Rebidding and Technical Parameters Guideline.[35]

### 3.3.2 Submissions on the proposed rule

A number of participants supported the AER's proposed rule in submissions, considering that the treatment of ramp rates and dispatch inflexibility profiles in the NER should be aligned with the current treatment of other technical parameters, such as frequency control ancillary services parameters, which must reflect the technical capabilities of the plant.[36]

However, other submissions on the consultation paper noted the significant level of ambiguity in the proposed rule with regards to how the maximum technical ramp rate would be defined.[37] Macquarie Generation contended that there are a number of factors that make it difficult to calculate an accurate ramping capability for the older coal-fired plant in the NEM, and that much is likely to rely on the knowledge and experience of control room operators in assessing the performance limits of a generating unit.[38]

The AER contended in its submission that participants are aware of their generator ramp rate capabilities based on the conditions of their plant and that, given a set of forecast conditions, a generator can predict, with reasonable certainty, what the ramping capability of the generator will be for a given level of output.[39]

The AER further noted that the intention would not be to scrutinise small differences between ramp rates offered by participants and some historical benchmark. Instead, when monitoring compliance, the intention would be to use extensive monitoring knowledge and 15 years of historical generator data to examine ramp rates that materially deviate from expected levels where market conditions create financial incentives to do so.

However, several participants maintained that enforcement of and compliance with the AER's proposed rule would create material uncertainty and would increase the cost of participation in the NEM and that any rule should be sufficiently specific to not result in ambiguity when assessing compliance.[40]

35 This guideline is available on the AER website. The AER may amend or replace the guideline from time to time in accordance with clauses 3.8.3A, 3.8.19(b)(2) and 3.8.22(c)(3) of the NER.

36 See submissions on the consultation paper from: Government of South Australia, p. 1; MEU, p. 3.

37 See submissions on the consultation paper from: InterGen, p. 1; Arrow Energy, pp. 4-5; Macquarie Generation, p. 2; AGL, p. 1; EnergyAustralia, p. 3.

38 Macquarie Generation, submission on the consultation paper, pp. 2-3.

39 AER, submission on the consultation paper, p. 3.

40 See submissions on the consultation paper from: Snowy Hydro, p. 15; Arrow Energy, p. 7; GDF Suez, p. 2; AGL, p. 1; EnergyAustralia, p. 2; NGF, p. 23.

Participants also cited the strong links that exist between ramp rates and commercial incentives.[41] GDF Suez noted that generators have an incentive to offer high ramp rates so that when the pool price exceeds their offer price, they can have their output increased quickly and thus maximise their pool revenue. Equally, when the pool price falls below the generator's bid price, the generator would generally want to ramp down as quickly as possible, to avoid being dispatched beyond their desired market level.[42]

Participants suggested that the AER's proposed rule would be inequitable as it would impose greater requirements on those generators that are able to provide greater ramp rate capability.[43] Flexible units would be required to be ramped down to a greater extent in order to alleviate constraints in the network at times of congestion. ACIL Allen suggested in its report to Snowy Hydro that the possibility of being constrained off without compensation as a result of having a responsive plant and having to submit at all times the safe maximum ramp rate would seem to be a deterrent to investment in peaking generation.[44]

The importance of efficient market outcomes as an incentive to invest in flexible plant was emphasised by both Alinta Energy and GDF Suez.[45] Both participants noted that ramping capability may become more valuable to the market over time as greater levels of intermittent renewable generation are introduced and the remaining thermal plant needs to continuously change generation patterns to cover the variations in supply.[46]

### 3.3.3 The Commission's assessment of the proposed rule

Having considered the issues raised in the AER's rule change request, and in light of submissions made by participants, the Commission does not support the AER's proposed rule. The Commission does not consider that generators should be required to provide the maximum ramp rate that they can safely attain at all times or that fast-start generators should be required to submit a dispatch inflexibility profile that always reflects the technical limitations of their plant.

The Commission considers that ramp rate capability is strongly linked to commercial incentives. For many generators in the NEM there is a strong commercial incentive to have a highly flexible plant. The Commission considers that the AER's proposed rule has the potential to create a disincentive to invest in flexible plant as it may

41 See submissions on the consultation paper from: EnergyAustralia, pp. 2-3; GDF Suez, p. 2; Snowy Hydro, pp. 16-17.

42 GDF Suez, submission on the consultation paper, p. 2.

43 See submissions on the consultation paper from: Arrow Energy, p. 5; Snowy Hydro, p. 16; EnergyAustralia, p. 2.

44 ACIL Allen Consulting, Review of aspects of AER's rule change proposal, report to Snowy Hydro, 27 March 2014, p. 10.

45 See submissions on the consultation paper from: Alinta Energy, pp. 8-9; GDF Suez, pp. 3-4.

46 See table 4.2 for an estimate of the change in aggregate regional ramp rate capability under the more preferable final rule.

disproportionately impact generators that are able to provide greater ramp rate capability.

By requiring generators to provide their maximum ramp rate at all times, the burden of ramp rate capability in the market would be shifted to more flexible plant. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes over the long term. The Commission considers that this is contrary to the NER principle of technology neutrality which provides that rules should not be made that apply special treatment in respect of different technologies used by participants.[47]

The Commission also considers that the proposed rule may impose a burden of compliance on generators to continuously review and update their maximum ramp rate requirements, thereby adding to operational and administration costs and increasing the level of uncertainty in compliance with the NER.

Further, the Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. Ramp rates and dispatch inflexibilities of generating plant are subject to a range of factors and the complexity of determining the maximum technical capability at any given time would involve a trade-off between capability and cost and may give rise to disagreements between the AER and generators.

47 See clause 3.1.4(3) of the NER.

# 4 The Commission's more preferable final rule

Although the Commission does not support the AER's proposed rule, it does have concerns in relation to the current arrangements. While the current minimum ramp rate requirements provide sufficient capability for AEMO to manage the secure operation of the electricity system, the Commission considers that the existing rules may prevent this from being achieved in an efficient manner.

This Chapter discusses the Commission's assessment of the current rules and sets out the reasoning for its more preferable final rule. The discussion also includes the reasoning for the more preferable draft rule that was made by the Commission on 28 August 2014, and the additional options that were published on 18 December 2014 in response to the practical issues that were raised by stakeholders with regard to the implementation of the more preferable draft rule.

## 4.1 Commercial incentives and system security

**Commercial drivers of ramp rate capability**

In the NEM, decisions to invest in generating plant are based on a range of factors that determine the ability to obtain a return on capital investment. Amongst its considerations, a prospective investor is likely to take into account the possible geographic location of the new plant and its ease of access across the transmission network to receive the regional energy price. A further important influence on investment decisions relates to the design of the NEM as an energy-only market. As generators do not receive payment based on their available capacity, many generators rely on relatively high wholesale market prices at time of scarcity to provide a significant share of their required revenue. The ability of these generators to provide energy at these discrete times is determined, not only by their access across the transmission network, but also by the flexibility of their generating units.

A generating unit that can ramp up generation output at the times that the market signals it is needed will be rewarded. Equally, when sufficient low-price energy is provided to meet demand and the price falls below the operating cost of the generating unit, a fast ramp down rate will reduce the potential losses. Generators may also have an incentive to maintain flexibility to support variations in their contract positions. As such, for many generators in the NEM there is a strong commercial incentive to have a highly flexible plant.

Efficient wholesale market price outcomes rely on the ability of generating units to provide energy when it is of most value. Rules that restrict the operating flexibility of generating units may diminish the incentives for investment in flexible plant. Over time, this is likely to give rise to inefficient wholesale price outcomes which is not in the long-term interests of consumers.

However, the Commission recognises that market conditions do not always give rise to a consistent set of commercial incentives for greater flexibility. Congestion in the transmission network can mean that generators have uncertain access to the market, in terms of their ability to be dispatched and receive the regional energy price. There is currently no mechanism that allows generators to hedge this risk. Instead, generators that are likely to be constrained off have an incentive to rebid to reduce the rate that they can be ramped down in order to reduce the extent to which their dispatch levels will be decreased.

**A requirement for minimum ramp rates**

In 2009, the AEMC made a rule in relation to a request received from the AER, which placed requirements on generators regarding their minimum offered ramp rates.[48] The rule change request 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 between Wallerawang Power Station and the Sydney South substation, 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.

The Commission's final determination on that rule change request imposed a minimum ramp rate of 3 MW/minute (or three per cent of capacity for generating units less than 100 MW) except where it could be demonstrated to NEMMCO that a lower ramp rate is required for technical or safety reasons. The rule required generating units that are aggregated to be treated as a single unit and provide a minimum ramp rate of 3 MW/minute.

The AER’s 2008 proposed rule to change ramp rates to a minimum of 3 MW/minute was principally driven by the fact that the lack of restrictions on scheduled generators to rebid ramp rates undermined the ability of NEMMCO to determine an efficient dispatch arrangement while maintaining system security. The AER explained that the ability of generators to reduce ramp rates could hinder the ability of market systems to rapidly adjust power flows to respond to issues that emerge in the market. The AER noted that NEMMCO was of the view that 3 MW/minute should accommodate the vast majority of system security issues that may arise in the context of the NEM.[49]

The Commission acknowledges that, given the commercial incentives caused by conditions of network congestion, a minimum level of ramp rate capability must be provided in the NEM in order to maintain the efficient and secure operation of the dispatch process and to ensure that system security can be maintained.

48 AEMC, *Ramp rates, market ancillary service offers, and dispatch inflexibility - final determination*, 15 January 2009.

49 The decision to use 3 MW/minute was based on an analysis of offers in 2007 which showed that all except a handful of generators offer at 3 MW/minute or greater most of the time. It was therefore determined that a level of 3 MW/minute minimum ramp rate would be sufficient for most generators.

## 4.2 Assessment of the current rules

In seeking to determine minimum ramp rate requirements, the Commission considers that under the existing arrangements, the burden of system ramp rate capability is not applied consistently for all generating units. The Commission notes that:

- a fixed requirement of 3 MW/minute for all generators above 100 MW means that the minimum required ramp rate as a proportion of plant capacity reduces as the capacity of the unit increases;
- if generating units are aggregated for the purposes of the market dispatch process then the minimum required ramp rate of 3 MW/minute applies to all generating units combined; and
- a separate rule effectively exists for generators with capacity less than 100 MW.

The Commission considers that system ramp rate capability is therefore disproportionately borne by smaller generators and non-aggregated generators.

By requiring certain generators to provide a disproportionately higher level of ramp rate capability, the Commission considers that the current rules have the potential to:

- inhibit AEMO's ability to optimise the dispatch process such that the production of electricity occurs through the most efficient means; and
- impact investment such that decisions on the size of generating units and levels of aggregation are not based purely on commercial and economic factors.

The Commission considers that there is potential to improve the current rules such that the provision of the minimum required level of ramp rate capability is applied consistently and proportionately for all participants.

## 4.3 The Commission's more preferable draft rule

In August 2014, the Commission determined to make a more preferable draft rule to require that ramp rates provided to AEMO are at least one per cent of maximum capacity on a MW/minute basis.

### 4.3.1 Reasons for the more preferable draft rule

The Commission considered that the more preferable draft rule would have contributed to the NEO by providing AEMO with a greater ability to optimise the NEM dispatch process more efficiently, thereby enhancing the efficient operation of electricity services for the long term interests of consumers.

- The requirements of the more preferable draft rule would have applied uniformly across all participants. The current arrangements apply a separate form of the rules to generators with capacity less than 100 MW. The more preferable draft rule would have removed this inconsistency in the rules that treats participants differently based on an arbitrarily determined benchmark level of capacity.

- For generators with capacity greater than 100 MW, the current arrangements apply a fixed minimum ramp rate requirement of 3 MW/minute which places a greater relative proportion of the burden on smaller generating units. The Commission's more preferable draft rule would have applied the same ramp rate requirements as a percentage of capacity to all participants and would have thereby distributed the burden of system ramp rate capability more evenly.
- Minimum required ramp rates under the more preferable draft rule would have not been arbitrarily influenced by whether or not generating units have been aggregated. The Commission considered there to be no basis on which minimum ramp rates should be determined by levels of aggregation. The more preferable draft rule would have ensured that aggregated and non-aggregated generators are treated on the same basis.

The draft rule would have avoided the potential negative impacts that the AER's proposed rule may have on the incentive to invest in generating plant with more flexible ramp rate capability. The more preferable draft rule would have aligned the minimum ramp rate requirements with the size of plant and would have been determined irrespective of generation technology. The intention of this was to contribute to investment decisions that are, to the greatest extent possible, based on commercial and economic factors, which would have contributed to efficient investment in electricity services for the long terms interests of consumers.

Further, the minimum required ramp rate would have been a constant that is not subject to variation, thereby minimising compliance costs. The Commission considered that this would have been preferable to the AER's proposed rule which would require ramp rates to be continuously updated to reflect the maximum technical capability of the plant at any given time. The Commission's more preferable draft rule would have provided certainty to generators and plant operators and would have minimised the risk of enforcement issues. It would also have minimised regulatory risk by providing investors with certainty in relation to the minimum required capability of generating plant, thereby reducing the potential costs of investment.

### 4.3.2 Issues with the more preferable draft rule

Submissions generally supported the Commission's more preferable draft rule in principle, but highlighted some specific concerns with its application in practice.

**Issues with aggregated units**

A number of stakeholders suggested that its practical application might lead to disproportionate or perverse outcomes in the particular case of aggregated units.

GDF Suez noted that the capability for aggregated units to ramp up and down is a function of how many physical units are on line at the time, and that a ramp rate requirement of one per cent of the maximum capacity of the aggregated unit may not be achievable unless sufficient physical units are online.[50]

Snowy Hydro provided examples in support of the argument that requiring aggregated units to provide ramp rates based on aggregate maximum capacity would be disproportionate, drawing the analogy that when an individually registered unit is shut down or not on line there would be no ramping requirement. Snowy Hydro proposed that, for aggregate units, the minimum required ramping capability should be based on the maximum capacity of the physical units which are online and synchronised. It suggested that market data is available which would allow the AER to verify and monitor compliance with such a requirement.[51]

Origin Energy and AEMO also both suggested that the maximum capacity used to calculate ramp rate requirements for aggregated units should reflect the number of units in service,[52] with AEMO highlighting that it holds data on the number of units in service and would be able to make this available to the AER if required.

**Issues with large thermal units**

A further specific issue raised by stakeholders related to the ability of some large thermal generating units to comply with the more preferable draft rule on a consistent basis.

AGL stated that, under the more preferable draft rule, some of its large generating plant (in particular, the Bayswater and Liddell power stations) would be unable to sustain the required ramp rates without incurring a substantial increase in operations and maintenance costs, or risking plant availability. AGL further suggested that other thermal generators in the NEM would be likely to encounter similar issues in attempting to comply with the requirements of the more preferable draft rule.[53]

Similarly, EnergyAustralia highlighted the example of the Mt. Piper power station, which would have a minimum ramp rate requirement of 7 MW/minute under the more preferable draft rule. EnergyAustralia suggested that the station does not always have the ability to ramp at 7 MW/minute, as ramp capacity is affected by coal quality, mill changes, generation level, and other physical constraints.[54]

CS Energy contended that the requirements of the more preferable draft rule may be excessive and that Kogan Creek power station, in particular, would not be able to attain a ramp rate of 7-8 MW/minute at higher generation levels, as the unit was not

50 GDF Suez, Submission to the Draft Determination, p. 2.

51 Snowy Hydro, Submission to the Draft Determination, pp. 2-3.

52 Origin Energy, Submission to the Draft Determination, p. 2; AEMO, Submission to the Draft Determination, p. 3.

53 AGL, Submission to the Draft Determination, p. 2.

54 EnergyAustralia, Submission to the Draft Determination, p. 1.

designed with the intention of fast ramping.[55] Origin Energy also suggested that the more preferable draft rule failed to recognise operational requirements for mill movements and plant impacts from increasing the thermal stress on units, with resulting increases in wear and tear costs and reductions in asset life.[56]

Both GDF Suez and Stanwell noted that the more preferable draft rule would provide relatively high ramping obligations on large generating units that could be difficult or costly for some units to meet,[57] and Hydro Tasmania raised concerns that the more preferable draft rule would lead to several permanent derogations for large machines which could not achieve the required ramp rates.[58]

### 4.3.3 The Commission's view

The Commission has considered the extent to which the issues raised in response to the draft determination place limits on the practical implementation of the more preferable draft rule.

The Commission notes that the rules currently allow participants to provide a ramp rate lower than their minimum requirement if an event or other occurrence physically prevents such a ramp rate from being attained or makes it unsafe to operate in that manner.[59] With regard to aggregated generators, the Commission considers that these provisions are likely to be sufficient to address the inability to meet the minimum ramp rate requirements when only one or two individual physical units are online.

However, the issues raised in regard of large thermal plant would not necessarily physically prevent them from attaining the requirements of the draft rule in the short-term, nor make it unsafe to do so; rather, consistently offering ramp rates at the required level on an ongoing basis would increase costs, with the potential to decrease efficiency over the longer term.

The Commission has considered whether it would be possible to amend the rules to allow for the requirements on affected large thermal units to be reduced on a case-by-case basis. However, given its view that a trade-off exists between the level of ramp rate capability offered and the costs incurred in doing so, the Commission has concluded that it would be difficult to formulate a mechanism that could allow for the objective differentiation of cases where efficiency concerns did and did not exist, and for the determination of a specific minimum ramp rate in each instance where a lower requirement was deemed appropriate.

This conclusion reflects the Commission's earlier concerns that, under the proposed rule, it would be problematic for the AER to assess whether ramp rates submitted by

55 CS Energy, Submission to the Draft Determination, p. 3-4.

56 Origin Energy, Submission to the Draft Determination, p. 4.

57 GDF Suez, Submission to the Draft Determination, p. 1; Stanwell, Submission to the Draft Determination, p. 3.

58 Hydro Tasmania, Submission to the Draft Determination, p. 2.

59 See clause 3.8.3A(c).

generators represents a true reflection of the technical capability of their generating units at any given time. This view that generator ramp rates contain elements of both technical and commercial considerations was supported in submissions on the draft determination.[60]

In light of this conclusion, the Commission has determined to make a more preferable final rule that would address the issues raised in submissions with the implementation of the Commission's more preferable draft rule, while still being likely to contribute to the NEO by meeting the Commission's objectives for ramp rate requirements that can be applied more consistently and proportionately than the current rules.

## 4.4 The Commission's more preferable final rule

As a consequence of the issues discussed in section 3.3 in relation to the proposed rule, and the issues discussed in section 4.3 in relation to the implementation of the Commission's more preferable draft rule, the Commission has determined to make a more preferable final rule that is different to the more preferable draft rule.

The Commission's more preferable final rule extends the current minimum ramp rate requirements to individual physical units that make up aggregated facilities.

Under the more preferable final rule, minimum ramp rate requirements will be as follows:

- for scheduled generating units, the lower of three per cent of maximum capacity or 3 MW per minute;
- for scheduled generating units that are aggregated, the lower of three per cent of maximum capacity or 3 MW per minute applied to individual physical units, then summed;
- for scheduled network services and scheduled loads, 3 MW/minute; and
- for scheduled network services and scheduled loads that are aggregated, 3 MW/minute applied to individual network services and individual loads, then summed.

As with the existing arrangements, the more preferable final rule will require that all minimum ramp rate requirements be rounded down to the nearest whole number but not less than 1 MW/minute.

The application of minimum ramp rate levels to individual physical units would result in an increase to the minimum ramp rate requirements for larger aggregated facilities, thereby bringing the requirements for aggregated units to a level more commensurate with those for individually registered units.

60 See submissions on the draft determination from: Origin Energy, p. 1; Snowy Hydro, p. 1; Stanwell, p. 1.

For example, under the current rules a generating plant with 3 individually registered units of 200 MW each would have a combined minimum ramp rate requirement of 3 x 3 MW/minute = 9 MW/minute, whereas the minimum ramp rate requirement for similar plant registered as an aggregated unit would be only 3 MW/minute for all 3 units combined. The more preferable final rule would increase the minimum ramp rate requirement of the aggregated generator to 9 MW/minute, consistent with the treatment of individually registered units.

### 4.4.1 Stakeholder submissions

The Commission consulted on the more preferable final rule as part of the options paper. The only significant concern raised by stakeholders was the disproportionately high minimum ramp rate requirements that may be imposed on some aggregated generators.

Submissions to the options paper from Snowy Hydro, Origin Energy, Stanwell and GDF Suez raised concern that, without a mechanism to adjust for the operating capability of the generating plant (as was included in another option consulted on), a disproportionately high ramping requirement would be placed on aggregated facilities when a number of individual physical units are unavailable.[61] Snowy Hydro suggested that this may result in perverse incentives to disaggregate plant which would lead to a less efficient outcome as more resources would be required to dispatch generation plant.[62]

However, analysis undertaken by AEMO in response to the options paper showed that there is not a strong correlation between the number of individual physical units in service and lower ramp rates offered by participants.[63]

**Box 4.1 Use of maximum availability to determine minimum ramp rate requirements for aggregated facilities**

In its options paper published on 18 December 2014, the Commission consulted on an alternative method of determining the minimum ramp rate requirements for aggregated facilities.[64] For aggregated facilities, the minimum requirements would be the lower of 3 MW/minute applied to each individual physical unit or one per cent of aggregate available capacity.

The purpose of determining minimum ramp rate requirements on the basis of available capacity was to address the concerns that some stakeholders raised that the more preferable draft rule would impose disproportionately high minimum

61 See submissions on the options paper from: Origin Energy, p. 2; Snowy Hydro, p. 4; Stanwell, p. 2; GDF Suez, p. 4.

62 Snowy Hydro, submission on the options paper, p. 5.

63 AEMO, submission on the options paper, p. 2.

64 AEMC, *Generator ramp rates and dispatch inflexibility in bidding – options paper*, 18 December 2014, pp. 15-19.

ramp rate requirements when a number of individual physical units were unavailable.

However, the Commission ultimately determined against the use of available capacity to determine the minimum required ramp rates of generating plant. The Commission agrees with the concern raised in a number of submissions that the variable nature of available capacity would result in dynamically changing compliance targets which may be difficult to regulate in practice and may increase the likelihood of compliance breaches by generators.[65]

The Commission was also concerned that the use of one per cent of available capacity in determining minimum ramp rates would result in a reduction in aggregate minimum ramp rate capability in a number of NEM regions. The Commission notes that such a reduction in ramp rate capability may still have a negative impact on the efficiency of dispatch outcomes. This view was supported by a number of stakeholders in submissions on the options paper.[66]

The Commission has considered whether it would be possible for the more preferable final rule to require that minimum ramp rate requirements be based on the number and capacity of the individual physical units that are generating at any point in time. However, clause 3.8.3A of the NER requires that ramp rates be submitted to AEMO as part of a generator’s offers or rebids, or as part of its notification of available capacity prior to dispatch. Given that the number of individual physical units generating is an outcome of the dispatch process, aggregated generators would be unable in practice to know their minimum ramp rate requirements at the time of submitting their offers.

### 4.4.2 Reasons for the Commission's more preferable final rule

The more preferable final rule retains most of the elements of the current arrangements but applies changes to the treatment of aggregated generators that the Commission considers would contribute to the achievement of the NEO. As such, the more preferable final rule will improve the consistency and proportionality in the application of minimum ramp rate requirements in comparison to the current rules. Table 4.1 provides a summary of the application of the current rules, more preferable draft rule, and more preferable final rule to aggregated and non-aggregated generators.

65 See submissions on the options paper from: EnergyAustralia, p. 1; AGL, p. 2; AER, pp. 1-2.

66 See submissions on the options paper from: AER, p. 2; SA Government, p. 1; AGL, p. 2; Stanwell, p. 2; MEU, p. 11.

**Table 4.1 Summary of minimum ramp rate requirements**

<table>
<tr><th></th><th>Current rules</th><th>More preferable draft rule</th><th>More preferable final rule</th></tr>
<tr><td>Non aggregated</td><td rowspan="2">Lower of three per cent of maximum capacity or 3 MW per minute, rounded down but no less than 1 MW/minute</td><td rowspan="2">One per cent of maximum capacity, expressed as MW/minute, rounded up</td><td>Lower of three per cent of maximum capacity or 3 MW per minute, rounded down but no less than 1 MW/minute</td></tr>
<tr><td>Aggregated</td><td>Lower of three per cent of maximum capacity or 3 MW per minute, rounded down but no less than 1 MW/minute, applied to individual physical units, then summed</td></tr>
</table>

### Optimisation of the dispatch process

The more preferable final rule would increase the consistency and proportionality in the application of the rule in comparison to the current arrangements by applying the minimum ramp rate requirements equally to aggregated and non-aggregated generators. By effectively applying minimum ramp rate requirements to individual physical units that make up aggregated generators, the burden of system ramp rate capability would no longer be disproportionately borne by non-aggregated generators. The benefit of the consistent treatment of aggregated and non-aggregated generators was supported by AGL in its submission to the options paper.[67]

A benefit of the more preferable final rule is that the consistent treatment of aggregated and non-aggregated facilities can only result in a net increase in the minimum ramp rate capability available to the market. While minimum ramp rate requirements for non-aggregated generators would remain the same as under the current arrangements, the minimum requirements for aggregated generators would increase. The revised requirements will result in an almost 30 per cent increase in aggregate minimum ramp rate capability across the NEM.

Given this additional level of minimum ramp rate capability, the more preferable final rule would therefore extend the set of feasible dispatch solutions, and so is likely to improve the efficiency of dispatch outcomes. Advice received from AEMO has confirmed that greater minimum ramp rate requirements increases the degrees of freedom available to the central dispatch process, which enhances the ability to find a more efficient solution. Submissions from the AER, AGL, the Major Energy Users (MEU), and the South Australian Government all noted that the resultant increase in

67 AGL, Submission on the options paper, p. 2.

aggregate ramp rate capability in all regions would likely improve the efficiency of dispatch outcomes.[68]

Under the more preferable final rule, the current minimum ramp rate requirements would be retained for non-aggregated facilities. Consequently, concerns raised by stakeholders in response to the draft determination that minimum required ramp rates under the more preferable draft rule may be too high for some large thermal generating units to comply with on a consistent basis would not apply.

However, by largely retaining the current arrangements, the final rule would not distribute the burden of system ramp rate capability as proportionately as the more preferable draft rule. The more preferable final rule does not ultimately address the problem that the current rules set minimum ramp rates with reference to a fixed parameter, and that minimum required ramp rates do not vary with unit size. In addition, the more preferable final rule retains the inconsistency in the current arrangements that sees a separate form of the rules applied to generators with capacity less than 100 MW.

Therefore, while the more preferable final rule does not apply minimum ramp rate requirements as consistently and proportionately as the more preferable draft rule, it is nevertheless an improvement on the current rules.

**Effect on investment in new generation technology**

The Commission considers that the decision to aggregate or disaggregate units should not be influenced by minimum ramp rate requirements. The more preferable final rule would establish minimum ramp rates that are consistent across aggregated and disaggregated units, and therefore would remove favourable minimum ramp rate requirements from the decision of whether or not to aggregate units.

However, the Commission notes that when investing in new generation plant, the decision of whether to aggregate a set of units is likely to be a relatively minor consideration. Any resultant increase in dynamic efficiency from the application of revised rules might therefore be relatively marginal.

As discussed in section 4.4.1, the Commission acknowledges the concern raised by some stakeholders that the more preferable final rule may impose a disproportionately high ramping requirement on aggregated facilities when a number of individual physical units are unavailable.[69]

However, the Commission considers that if an aggregated generator has only one or two individual physical units online, and as a consequence is unable to physically attain the minimum ramp rate requirements, then this is likely to constitute a sufficient reason under the rules to provide a ramp rate that is lower than their minimum

68 See submissions on the options paper from: AER, p. 1; AGL, p. 2; MEU, p. 11; Government of South Australia, p. 2.

69 See submissions on the options paper from: Origin Energy, p. 2; Snowy Hydro, p. 4; Stanwell, p. 2; GDF Suez, p. 4.

requirement. This view was supported by AEMO in its response to the options paper.[70]

In these circumstances, the generator would be required to submit a ramp rate that is the maximum it can safely attain.

## 4.5 Application of the more preferable final rule

For scheduled and semi-scheduled generators, the Commission's more preferable final rule would require participants to provide, for each individual physical generating unit, an up ramp rate and a down ramp rate that is at a minimum the lower of 3 MW/minute or three per cent of maximum capacity.

For scheduled network services and scheduled loads, the minimum requirements would be 3 MW/minute applied to each individual network service or individual load.

The more preferable final rule will require that all minimum ramp rate requirements be rounded down to the nearest whole number but not less than 1 MW/minute.

The more preferable final rule will also implement a change to clause 3.13.3 of the NER for participants to provide additional standing data to AEMO with regard to the number and capacity of each individual physical unit that make up aggregated facilities. This additional data will be used to determine minimum ramp rate requirements.

The Commission has assessed the impact of this rule on the market and, based on advice received from AEMO, is satisfied that it would maintain AEMO's ability to manage the secure operation of the electricity system. Table 4.2 shows how aggregate ramp rate capability would be affected for each region of the NEM.

**Table 4.2 Regional change in aggregate minimum ramp rate requirements**

| Region | Current aggregate ramp rate capability (MW/minute) | Draft rule aggregate ramp rate capability (MW/minute) | Difference (MW/minute) | Final rule aggregate ramp rate capability (MW/minute) | Difference (MW/minute) |
|---|---|---|---|---|---|
| New South Wales | 94 | 124 | 30 (32%) | 126 | 32 (34%) |
| Queensland | 124 | 129 | 5 (4%) | 133 | 9 (7%) |
| South Australia | 61 | 57 | -4 (-7%) | 80 | 19 (31%) |
| Tasmania | 48 | 37 | -11 (-23%) | 64 | 16 (33%) |
| Victoria | 95 | 114 | 19 (20%) | 140 | 45 (47%) |

70 AEMO, submission on the options paper, pp. 1-2.

Analysis undertaken using AEMO data suggests that individual generators should be able to meet their minimum requirements under the more preferable final rule. However, if individual participants are unable to meet the minimum requirements for physical or plant safety reasons, the more preferable final rule would retain the existing provisions that allow the generator to provide a brief, verifiable, and specific reason to AEMO as to why the ramp rate provided is below the minimum required.[71]

In a situation where the participant is unable to meet the minimum requirement, it must provide a ramp rate that is the maximum it can safely attain at the time. The AER would retain the ability to seek additional information from participants to substantiate and verify the reasons provided.[72] Further, generators may elect to change their maximum ramp rates provided to AEMO as part of bid and offer validation data in accordance with schedule 3.1 of the NER.

While the final rule does not include any changes to the requirements in relation to dispatch inflexibility profiles, the Commission notes that the current requirements in the rules impose a degree of constraint on generators to make changes to time inflexibilities in their dispatch inflexibility profiles. The Commission considers that this has the potential to limit the extent to which generators can use dispatch inflexibility profiles to achieve commercial objectives at times of network congestion. A further discussion of dispatch inflexibility profiles is provided in **Appendix B**.

The Commission has determined that the rule will commence from 1 July 2016. This date has been selected to provide sufficient time for:

- the next scheduled update to AEMO's systems to occur in May 2016 to implement new minimum ramp rate requirements for participants with aggregated facilities; and
- a period of transition for participants to manage their forward hedge contract position to accommodate the change in minimum ramp rate requirements for aggregated facilities, with the first day in the financial year chosen to align with the standard period for contracting.

71 Clause 3.8.3A(c)-(e) of the NER.

72 Clause 3.8.3A(f) of the NER.

## Abbreviations

| | |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| AEMC or Commission | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| CVP | constraint violation penalty |
| MCE | Ministerial Council on Energy |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEMDE | National Electricity Market Dispatch Engine |
| NEMMCO | National Electricity Market Management Company |
| NEO | National Electricity Objective |
| NER | National Electricity Rules |
| NGF | National Generators Forum |
| TUOS | transmission use of system |

# A Legal requirements under the NEL

This appendix sets out the relevant legal requirements under the National Electricity Law (NEL) for the AEMC in making this final rule determination.

## A.1 Final determination

In accordance with sections 102 and 103 of the NEL, the Commission has made this more preferable final rule and associated final determination in relation to the rule proposed by the Australian Energy Regulator.

## A.2 Power to make the rule

The Commission is satisfied that the proposed rule falls within the subject matter about which the Commission may make rules. The proposed rule falls within section 34 of the NEL as it relates to the operation of the NEM (section 34(1)(a)(i)), the operation of the national electricity system for the purposes of the safety, security and reliability of that system (section 34(1)(a)(ii)), and the activities of persons (including Registered participants) participating in the NEM or involved in the operation of the national electricity system (section 34(1)(a)(iii)).

## A.3 Commission's considerations

In assessing the rule change request the Commission considered:

- the Commission’s powers under the NEL to make the rule;
- the rule change request;
- the fact that there is no relevant Ministerial Council on Energy (MCE) Statement of Policy Principles;[73]
- submissions received during three rounds of consultation; and
- the Commission’s analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

## A.4 Power to make a more preferable rule

Under section 91A of the NEL the Commission may make a rule that is different (including materially different) from a market initiated proposed rule if the

73 Under section 99(2)(a)(iv) of the NEL, the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for Energy. On 1 July 2011 the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated Council is now called the COAG Energy Council.

Commission is satisfied that, having regard to the issues or issues that were raised by the market initiated proposed rule, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

As discussed in Chapter 2, the Commission has determined to make a more preferable final rule. The reasons for the Commission's decision are set out in Chapter 4.

## A.5 Civil penalty provision

The Commission's more preferable final rule amends clause 3.8.3A(b) of the NER and inserts a new clause 3.13.3(b1). Clause 3.8.3A(b) and clauses 3.13.3(b) to (c) are currently classified as civil penalty provisions under the National Electricity (South Australia) Regulations.

The Commission may recommend that these clauses be retained as civil penalty provisions, but must notify the COAG Energy Council of the policy rationale for taking this course of action. The Commission considers that clause 3.8.3A(b) and clause 3.13.3(b1) should be classified as civil penalty provisions because a breach of these clauses could pose a risk to the secure operation of the NEM. In addition, the classification of these clauses as civil penalty provisions would encourage compliance by relevant parties with these provisions.

## A.6 Others

Under section 91(8) of the NEL, the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions. The more preferable final rule is compatible with AEMO's declared network functions because it does not affect AEMO's performance of those functions.

# B Ramp rates and dispatch inflexibility profiles

This appendix provides a discussion of the current treatment and history of ramp rates and dispatch inflexibility profiles in the NEM.

## B.1 Ramp rates

On 10 December 1997, the Australian Competition and Consumer Commission (ACCC) authorised amendments to the National Electricity Code (the Code) in preparation for the commencement of the NEM.[74] In the final determination, the ACCC refrained from imposing any conditions regarding the rebidding of dispatch parameters, such as capacity, ramp rates, dispatch inflexibility and energy constraints.[75]

In April 2008, the AER proposed changes to the rules relating to the bidding and rebidding of ramp rates.[76] The AER contended that the rules permitted generators to rebid ramp rates in such a way to inhibit the market operator's ability to reduce the output of generators through central dispatch to manage system security.

In making the rule, the AEMC largely adopted the AER's proposal with some modifications.[77] The AEMC's final determination changed clause 3.8.3A of the NER to require participants to submit a minimum ramp rate of 3 MW/minute except where it can be demonstrated that a lower ramp rate is required for technical or safety reasons.

The AER's proposed rule to change ramp rates to a minimum of 3 MW/minute was principally driven by the fact that the lack of restrictions on scheduled generators to rebid ramp rates undermined the ability of NEMMCO to manage system security in an economically optimal fashion. The AER cited events of October 2005 in New South Wales and October and November 2007 in Queensland where system security was compromised through the rebidding of ramp rates. The AER explained that the ability of generators to reduce ramp rates could hinder the ability of market systems to rapidly adjust power flows to respond to issues that emerge in the market.

In proposing a minimum ramp rate of 3 MW/minute, the AER analysed ramp rates from 2007 that showed all except a small number of generators offer at 3 MW/minute or higher. The AER therefore concluded that past ramp rate bidding indicated that a 3 MW/minute minimum ramp rate would not cause undue wear and tear on plant.

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74 The ACCC's responsibility for authorising changes to the Code reflects earlier regulatory arrangements in the NEM. The provisions contained in the Code were transferred to the NER at its inception in July 2005. The AEMC has responsibility for administering and determining changes to the NER.

75 ACCC, *Amendments to the National Electricity Code Changes to bidding and rebidding rules*, 4 December 2002, p. 5.

76 AER, *Request for rule changes – technical parameters*, 21 April 2008.

77 AEMC, *Ramp rates, market ancillary service offers, and dispatch inflexibility – final determination*, 15 January 2009.

Furthermore, the market operator at the time considered that 3 MW/minute should accommodate the majority of system security issues that may arise in the NEM.[78]

During consultation on the rule change request, stakeholders raised concern that a minimum fixed ramp rate of 3 MW/minute would place a disproportionate burden on smaller generators who would be required to change output at a rate equivalent to a higher relative proportion of their overall capacity.

To address this concern, the AEMC determined that the minimum ramp rate required by generators should be the lower of 3 MW/minute or 3 per cent of capacity rounded down to the nearest whole number. This implied that generators with a capacity less than 100 MW would be required to maintain a minimum ramp rate of either 2 MW/minute or 1 MW/minute.

Stakeholders also raised concern that a minimum fixed ramp rate would create incentives to aggregate generating units. Stakeholders suggested that commercial incentives could see generators aggregate units in order to diminish their aggregate ramping capability.

However, the AEMC noted that the rules provided NEMMCO with the ability to reject or place conditions on applications for aggregation if the approval of an application for aggregation would affect power system security or materially distort central dispatch. As such the AEMC determined that a minimum ramp rate of the lower of 3 MW/minute or 3 per cent of the registered unit size would apply to both aggregated and non-aggregated generating units (as opposed to individual physical generating units).

Under the NEL, the AER's enforcement role and powers allow it to investigate and take action against a possible breach of the rules. The AEMC supported the AER's proposal that the requirement for generators to meet a minimum ramp rate of 3 MW/minute be a civil penalty provision and recommended to the MCE that this provision be included as a civil penalty provision in the National Electricity (SA) Regulations. The AEMC also determined that the AER may request additional information from the relevant scheduled generator or market participant to verify a reason provided for a ramp rate below the minimum.

The Commission considered that the objective of the AER's rule change request was to provide NEMMCO with sufficient ramp rate capability for it to be able to manage power system security. The decision at the time to use 3 MW/minute as the minimum value was based on advice from NEMMCO that this would be sufficient to allow the effective management of system security incidents.

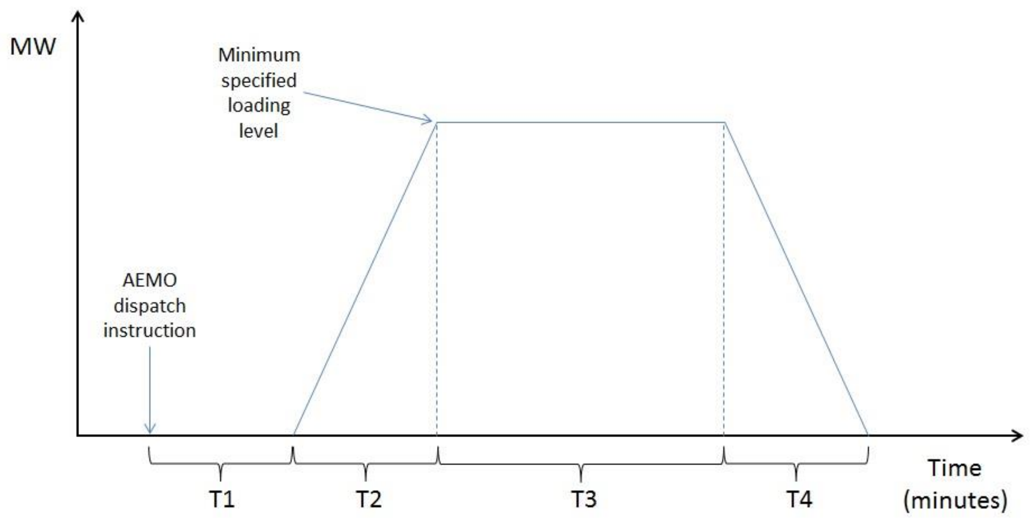
78 Ibid, p. 7.

## B.2 Dispatch inflexibility profiles

Dispatch inflexibility profiles are used by fast start plant such as gas turbines, to inform the dispatch process of inflexibilities in respect of their units such as minimum start and stop times, and minimum safe operating levels.

Clause 3.8.19(d) of the NER currently provides fast start generators with the discretion to include a dispatch inflexibility profile as part of its dispatch offer. As shown in figure B.1, a dispatch inflexibility profile must contain parameters to indicate its MW capacity and time related inflexibilities.

**Figure B.1 Dispatch inflexibility profile**




Along with a minimum specified MW loading level, the dispatch inflexibility profile must also include:

- the time following the issue of a dispatch instruction by AEMO to increase loading level from 0 MW (T1);
- the time the plant requires to reach the specified minimum loading level (T2);
- the time that the plant requires to be operated at or above its minimum loading level before it can be reduced below that level (T3); and
- the time following the issue of a dispatch instruction by AEMO to reduce loading from the minimum loading level to 0 MW (T4).

The NER places a number of constraints on the time related inflexibilities that can be provided in a dispatch inflexibility profile, including that:

- T1, T2, T3 and T4 must all be greater than zero;
- the sum T1+T2 must be less than or equal to 30 minutes; and
- the sum T1+T2+T3+T4 must be less than 60 minutes.

# C Summary of issues raised in submissions on the Consultation Paper

| Stakeholder | Comment | AEMC response |
|---|---|---|
| **AER's rule change proposal** | | |
| AER | Proposed rule will not address all of the costs associated with disorderly bidding and its consequences, but it will reduce the likelihood and duration of such market outcomes, while improving the efficiency of the operation of the market more generally (p. 3). | The Commission has not been persuaded that it would be appropriate to make a potentially extensive change to generators' minimum ramp rate requirements that does not also address the range of other factors that may contribute to the costs raised. |
| GDF Suez | Review of generators acting to limit ramping capability is appropriate, however, not supportive of the proposal for generators to provide their maximum technical ramping capability at all times. Ramp rates are a commercial parameter as it is in a generator's commercial interest to ramp up and down with changing pool price. As such, GDF Suez does not support regulatory measures being imposed on the NEM which seek to mandate the provision of a product or service which is not a technical condition for generator connection. A requirement for generators to continually update their ramping capability, and for the regulator to monitor compliance, would be unnecessarily burdensome (p. 1). | The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. The Commission considers that the AER's proposed rule has the potential to create a disincentive to invest in flexible plant as it would disproportionately impact generators that are able to provide greater ramp rate capability.<br><br>The Commission also considers that the proposed rule would impose a burden of compliance on generators to continuously review and update their maximum ramp rate requirements, thereby adding to operational and administration costs and increasing the level of uncertainty in compliance with the NER. |
| Origin Energy | Origin Energy notes that the materiality of the problem the rule change is intended to solve has | While acknowledging the AER's concerns in relation to inefficient outcomes caused by |

| Stakeholder | Comment | AEMC response |
|---|---|---|
| | not been established. Both the incidence and impact of the market outcomes are not of a sufficient magnitude to warrant the introduction of the proposed rule. Origin also note that imposing a requirement on generators to submit ramp rates reflecting their maximum technical capacity at all times would impose additional risk and increase operating and maintenance costs. (p. 1.) | generators rebidding ramp rates to low levels at times of network congestion, the Commission considers that there has been no compelling evidence produced to date that suggests that the costs to the market are likely to be material in the context of the NEM as a whole. |
| Macquarie Generation | The proposed rule would require generators to constantly update their maximum technical ramp rate capability. This could dramatically increase the frequency of rebidding for coal-fired generators as plant conditions change and ramp rate capability moves up or down. Considers that the AER's proposal for an after-the-fact review of whether a generator has complied with ramp rates does not reflect reality. In practice, spot traders and control room operators need to make snap judgements at times of variable and sometimes volatile plant and market conditions (p. 4). | The Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. Ramp rates and dispatch inflexibility profiles of generating plant are subject to a range of factors and the complexity of determining the maximum technical capability at any given time would involve a trade-off between capability and cost and may give rise to disagreements between the AER and generators. See section 3.3.3. |
| Arrow Energy | Supports the need to ensure that system security is not at risk and that economically efficient price outcomes are achieved. Concerned about the implications of requiring generators to always offer and potentially run at their technical maximum ramp rate capability (p. 2). | The Commission considers that, while the AER's proposed rule would provide the required minimum level of ramp rate capability to manage the secure operation of the electricity system, it may also create a disincentive to invest in flexible plant by disproportionately impacting generators that are able to provide greater ramp rate capability. Over time, this may affect commercial investment decisions regarding the flexibility of plant, potentially resulting in inefficient price outcomes in the long term interests of consumers. |

| Stakeholder | Comment | AEMC response |
|---|---|---|
| **Determining and enforcing ramp rates** | | |
| AER | Given a set of forecast conditions, a generator can predict, with reasonable certainty, what the ramping capability of the generator will be for a given level of output. The rules currently require generators to provide the maximum ramp rate they can safely attain at the time when they offer a ramp rate below 3 MW/minute. The proposed rule would extend this to offer the maximum they can safely attain at all times. When monitoring compliance of ramp rates, the intention is to use 15 years of historical generator data to examine ramp rates that materially deviate from expected levels, where market conditions create financial incentives to reduce the ramp rate below the unit's maximum technical capability. Intention is not to scrutinise small differences between ramp rates offered by participants and some historical benchmark, nor analyse in detail when a participant's ramp rate is moving through a range of values, consistent with movements in output (pp. 1-3). | The Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. Ramp rates and dispatch inflexibilities of generating plant are subject to a range of factors and the complexity of determining the maximum technical capability at any given time would involve a trade-off between capability and cost and may give rise to disagreements between the AER and generators. |
| MEU | Each generator should be able to advise the maximum ramp rates for each individual generator in its fleet. These ramp rates should be interrogated by AEMO and the AER to ensure that the generators are not artificially de-rating the ramp rates that are technically achievable (p. 20). | |
| AER | It would not be appropriate for generators to use the ramp rate submitted in accordance with schedule 3.1 as a default ramp rate. This is only to | The Commission is concerned that the proposed rule may be difficult to apply in practice as it would require the AER to determine whether the ramp |

| Stakeholder | Comment | AEMC response |
| --- | --- | --- |
| | be used for verification and compilation of dispatch bids and offers in the trading day schedule. It is not a regulatory provision but rather a tool for validation. Rather than submitting the maximum ramp rate as defined in the rules, the expectation would be for generators to submit ramp rates that reflect the maximum achievable under the conditions at the time, or expected output of plant under anticipated conditions in the forecasting horizons (p. 4). | rates or dispatch inflexibility profiles submitted by generators represent a true reflection of the technical capability of their generating units at any given time. See section 3.3.3. |
| AER, SA Government | Proposed rule brings ramp rates and dispatch inflexibility profiles into line with the other technical characteristics of an offer, for instance those related to ancillary services or when a generator declares itself inflexible and is unable to follow dispatch instructions (p. 5, p. 1). | The Commission considers that ramp rate capability is strongly linked to commercial incentives. For many generators in the NEM there is a strong commercial incentive to have a highly flexible plant. The Commission considers that the AER's proposed rule has the potential to create a disincentive to invest in flexible plant as it would disproportionately impact generators that are able to provide greater ramp rate capability. See section 3.3.3. |
| SA Government | Current requirement of 3 MW/minute was determined arbitrarily by reviewing previous bidding behaviour to address the fact that the lack of restrictions on scheduled generators to rebid ramp rates undermined the ability of NEMMCO to manage system security in an economically optimal fashion. While improving on the previous situation, the arbitrary 3 MW/minute limit has no technical basis and still results in unintended outcomes (p. 1). | The Commission acknowledges that, given the commercial incentives caused by conditions of network congestion, a minimum level of ramp rate capability must be provided in the NEM in order to maintain the efficient and secure operation of the dispatch process and to ensure that system security can be maintained. The more preferable draft rule would ensure that the rules that determine minimum ramp rate requirements are applied consistently and proportionately to all generators, which should provide for more efficient wholesale market outcomes in the interests of |

| Stakeholder | Comment | AEMC response |
|---|---|---|
| | | consumers. |
| Snowy Hydro | It is not valid to assume that generators would generally be able to operate at their maximum ramp rates submitted in accordance with schedule 3.1. In some circumstances Snowy Hydro's plant could achieve much higher ramping but at very significant increased cost and risk and in other circumstances much less ramping rates than those submitted in schedule 3.1. Cost differences associated with different levels of ramp rates are very material and sensitive between different generation technologies. There would be many technical issues and assumptions made to determine maximum ramp rates (p. 14). | The Commission recognises that in determining the ramp rates to apply to each of their generating units, generators currently take into account the costs associated with wear and tear and the risks of damage to plant. Therefore, each generator is likely to have a range of ramp rates that they consider to be typical of the technical capability of their generating units to which a range of costs may apply. As such, there is a trade-off that exists between the ramp rate capability provided and the costs to the generating unit. Therefore, the determination of ramp rates may not be a purely technical exercise as characterised by the AER. |
| Snowy Hydro | It would be sub-optimal and completely ineffectual for generators to negate wear and tear through bidding volumes within price bands. There is only limited ability to manage dispatch ramping in this manner. The proposal will considerably alter incentives on highly flexible generators. Energy constrained hydro generators are driven by the scarce energy resources to offer at the margin of the market. The AER seems to be proposing that these generators should vary the marginal priced energy offers to manage the commercial cost and risks of excessively high technical ramping impact on plant (p. 17). | The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. The Commission considers that the AER's proposed rule may create a disincentive to invest in flexible plant by disproportionately impacting generators that are able to provide greater ramp rate capability. |
| AGL | AGL considers there is merit in exploring applying the existing 3 MW/minute rule to individual physical generation units. This would provide additional ramping capability to NEMDE under certain | The Commission's more preferable final rule has essentially adopted this approach. The final rule should result in more efficient wholesale outcomes and should promote more efficient generation |

| Stakeholder | Comment | AEMC response |
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| | network conditions. AGL has a number of aggregated units and would support changing the rules in this way (pp. 1-2). | investment in the long term interests of consumers. See section 4.4.2. |
| EnergyAustralia | Accept that the current arrangements may create a regulatory distortion that encourages generators to aggregate individual units to benefit from the fixed minimum of 3MW/minute. A pragmatic and administratively simple alternative to deliver a step change increase in ramp capability would be to apply the current limit to each unit (p. 3). | |
| GDF Suez | Support a minimum ramping requirement and it may be useful to reconsider if 3 MW/minute is still appropriate. However, the level should not be set to the maximum that is technically possible. A potential solution could be for the transmission network service provider (TNSP) to negotiate a form of network agreement with the relevant generator to provide additional ramping capability on a fee-for-service arrangement. Another potential solution is for the 3 MW/minute to be applied on a physical unit basis rather than applied to aggregated totals. Need to consider how ramping capability can be better valued as it becomes more valuable with the increasing presence of intermittent renewable generation (p. 3). | The Commission considers that the rules should require participants to provide a minimum level of ramp rate capability at all times, consistent with AEMO's ability to provide system security. The Commission considers that the proposal to apply 3 MW/minute to individual physical units is likely to be workable in providing the necessary minimum level of ramp rate capability to ensure system security. |
| Origin Energy | Imposing a requirement to offer a maximum technical capacity at all times would impose additional risk on generators and increase operating and maintenance costs. Under congestion conditions or when constraints bind, many of the issues identified by the AER are likely | The Commission has not been persuaded that it would be appropriate to make a potentially extensive change to generators' minimum ramp rate requirements that does not also address the range of other factors that may contribute to the |

| Stakeholder | Comment | AEMC response |
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| | to still occur even if the proposed rule was in place. It is therefore worth considering the likely effectiveness of the AER's proposed changes when considering the adoption or a rule that will limit the operations of NEM participants (pp. 4-5). | costs raised. |
| Arrow Energy | Propose that generators are required to offer two ramp rates – one a technical maximum and the other a lower technical limit or commercial level. The CVP that applies to the latter could be set at below that of system security allowing NEMDE to dispatch those units in advance of potentially increasing system risk. Could also consider separate ramp rates from the energy offer to allow transparent bidding and costing of ramp rates. This would allow generators with multiple ramp rate modes to recover increased costs for different rates. Could also consider limiting the ability to change ramp rates to once within a particular half hour (this would still require the ability to rebid ramp rates if not technically achievable) (p. 6). | The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. However, the Commission considers that a minimum level of ramp rate capability is necessary in order to provide AEMO with the flexibility to manage the secure operation of the electricity system. The Commission's more preferable final rule would provide this ramp rate capability on a consistent and proportionate basis. |
| MEU | The need to use the maximum ramp rate only applies when there is a constraint. So the requirement to advise on ramp rates should have at least two features - one where the preferred ramp rate is advised where its cost reflects the usual operation of the equipment and a second where the technical maximum is advised, but only to be used when there is a constraint (p. 20). | |
| MEU | The application of using a percentage of capacity would result in fast start gas turbines having lower ramp rates than large coal fired power stations. | The Commission considers that a requirement for ramp rates to reflect technical capabilities would advantage certain technology types over others. |

| Stakeholder | Comment | AEMC response |
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| | This approach is inconsistent with actual equipment performance (p. 24). | Minimum required ramp rates that are equal to a proportion of the capacity of generating plant would ensure that the rules are applied consistently and proportionately to all participants, which would promote more efficient wholesale market outcomes. |
| **Management of system security and stability** | | |
| Snowy Hydro | The 3 MW/minute was set by AEMO and has not been an issue for system security. Looking forward with the oversupply of the NEM and the decline in demand growth the current ramping requirement would continue to sufficiently meet AEMO's system security obligations. Furthermore AEMO has the safety net power of direction and if ramping capability was indeed compromising system security, then AEMO could propose an explicit market for the offering of this service (p. 6). | The Commission notes that the minimum required ramp rate of 3 MW/minute was considered to be sufficient to manage the NEM power system under normal circumstances at the time of the previous rule determination in 2009, and that AEMO confirms that this continues to be the case. See section 3.1.3. |
| NGF | The NEM has no problems with system security. AEMO can direct participants at any time to change dispatch rather than rely on the market dispatch should there be risk of an insecure operating state (p. 3). | While AEMO maintains the power to direct generators to change output in the interests of system security, the Commission is satisfied that such an occurrence is unlikely to occur under normal circumstances given the existing minimum requirements of 3 MW/minute. See section 3.1.3. |
| Origin Energy | Origin consider there is no network security issue. AEMO previously advised that 3 MW/minute was sufficient to manage system security incidents. AEMO’s powers to override generator offers by issuing directions is an additional tool that can be used to manage power system stability and security (p. 4). | |

| Stakeholder | Comment | AEMC response |
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| **Productive efficiency losses** | | |
| SA Government | Generators using ramp rates to avoid volume risk from high prices is inconsistent with the objective of an efficient dispatch where the least cost generation is used to meet demand, thereby being inconsistent with the NEO (p. 2). | A generator's offers may take into account a range of factors, such as the opportunity costs of not being dispatched. Rebidding of ramp rates by generators that inhibits a market dispatch arrangement in strict accordance with the ranking of price and volume might not always imply a productive efficiency loss. See section 3.2.3. |
| SACOSS | All avenues of efficiency losses should be closed off. An argument that the impacts of rebidding ramp rates may be minor compared to other forms of rebidding is not a justification for inaction (p. 5). | The Commission has not been persuaded that it would be appropriate to make a potentially extensive change to generators' minimum ramp rate requirements that does not also address the range of other factors that may contribute to the costs raised. |
| Snowy Hydro | The current minimum ramp rate has a negligible impact on AEMO's ability to determine efficient dispatch. The rebidding of ramp rates and changes to dispatch inflexibility profiles is not the underlying cause of inefficient dispatch. Multiple and non-credible transmission outages taken at inappropriate times were the primary cause of the volatile market events in 17 of the 20 events highlighted in the AER Special Report released in December 2012 (p. 6). | The Commission recognises that there are a range of factors that can create the conditions in the market that give rise to inefficient dispatch. These conditions may include generators rebidding ramp rates or changing dispatch inflexibility profiles, but may also include other factors unrelated to generator rebidding that impact the capability of the network, such as the timing of network outages. |
| Snowy Hydro | Dispatch inefficiency due to disorderly bidding (to which only a small quantum can be attributed directly to ramp rates) is immaterial in total as shown by two separately commissioned reports - AEMC 2008 (Frontier Economics) which showed | The Commission acknowledges the results of earlier studies undertaken to estimate the extent of productive efficiency losses arising from generator rebidding activities, which suggests these are likely to be small relative to total market turnover. |

| Stakeholder | Comment | AEMC response |
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| | $8m pa and NGF 2013 (Frontier Economics) which showed $10m pa. This is compared to a total market turnover of approximately $9 billion (p. 7). | |
| Snowy Hydro | It is not valid to conclude that changes in the merit order of dispatch necessarily imply productive efficiency losses. While dispatch outcomes in the NEM might be expected in many cases to conform with the “merit order of dispatch” as the stacking of generator dispatch offers in increasing order of offer price, the optimisation of dispatch in the NEM is a co-optimisation of dispatch in the energy and ancillary services markets subject to a variety of constraints. The AER has not provided an estimate of productive efficiency losses attributable to rebidding of ramp rates (p. 9). | The AER's view that generators rebidding ramp rates under constraint conditions leads to productive efficiency losses appears to be predicated on an assumption that a generator's offers are representative of their operational costs. However, the Commission considers that a generator’s offers may also take into account a range of other factors, such as the opportunity costs of not being dispatched. As such, the rebidding of ramp rates by generators that inhibits a market dispatch arrangement in strict accordance with the ranking of price and volume offers might not necessarily imply a productive efficiency loss. See section 3.2.3. |
| EnergyAustralia | Agree that the priority afforded to ramp rates in dispatch can lead to inefficient dispatch outcomes in certain circumstances. However, the materiality of the issue has not been established. Any response should be proportionate and ensure the benefits outweigh the costs (p. 2). | The Commission notes the results of earlier studies that have estimated productive efficiency losses to be small relative to total market turnover. |
| Arrow Energy | Ramp rates and dispatch inflexibilities may only be a symptomatic part of the underlying problem and that other factors may potentially have a greater bearing. Arrow does not see a significant difference between ramp rate bidding and other forms of bidding behaviour, and therefore does not believe that the proposed rule change would reduce the extent of productive efficiency losses | The Commission recognises that there are a range of factors that can create the conditions in the market that give rise to inefficient dispatch. |

| Stakeholder | Comment | AEMC response |
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| | (p. 3). | |
| MEU | Efficient dispatch requires the lowest cost generator to be dispatched first and offloaded last. If this merit order is violated because of artificial ramp rates being imposed, then the outcome is not efficient (p. 14). | The Commission considers that a minimum level of ramp rate capability is necessary in order to provide AEMO with the flexibility to manage the secure operation of the electricity system. Determining the minimum required ramp rates as a percentage of a generating unit's capacity would promote the efficient operation of electricity services by not advantaging one technology type over another or benefiting aggregated units when generators are required to reduce output through the market dispatch process. This should improve the ability of AEMO to optimise the market dispatch process more efficiently while maintaining the secure operation of the electricity system, which would promote more efficient wholesale market outcomes in the interests of consumers. |
| **Counter-price flows between NEM regions** | | |
| Snowy Hydro | The root cause of the counter-price flow events has been multiple non-credible transmission outages. This has equated to 97% of negative settlement residues for the VIC to NSW interconnector and 91% for the NSW to VIC interconnect. It should be noted that AER is responsible for administering the various TNSP incentive schemes that should in theory incentivise the TNSP to schedule planned transmission outages at benign market times (p. 8). | The Commission recognises that there are a range of factors that can create the conditions in the market that give rise to counter-price flows. These conditions may include generators rebidding ramp rates or changing dispatch inflexibility profiles, but may also include other factors unrelated to generator rebidding that impact the capability of the network, such as the timing of network outages. See section 3.1.3. |
| Origin Energy | Not convinced that counter-price flows create costs for customers as customers would benefit from the | |

| Stakeholder | Comment | AEMC response |
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| | lower wholesale spot price in the importing region. Origin also note that the principle whereby customers in the importing region fund shortfalls brought on by negative residues was based on the assumption that these customers would benefit from the lower wholesale spot prices from the interconnector flows (p. 3). | |
| **Effectiveness of inter-regional hedging** | | |
| Snowy Hydro | The use of settlement residue auction (SRA) units is highly risky and unpredictable as a myriad of factors can impact the effectiveness of the SRA units. The majority of all contracting is done intra-regional with generators selling predominantly in their own pricing region. The loss of contract volume as a result of the proposed rule would not be replaced by generators remote from the region due to the increase risk of inter-regional trading and the imperfect nature of the SRA units. The net impact would be a decrease in the overall volume of contracts available to the market. This loss in contract market efficiency would be orders of magnitude greater than any incremental increase in dispatch efficiency (p. 13). | The Commission considers that commercial incentives are a key driver for the ramp rate capability of generators and that, for many participants, flexibility is necessary to provide energy to the market at times of highest value. Generators may have an incentive to maintain flexibility to support variations in their contract positions. Rules that attempt to prescribe fixed requirements on ramp rate capability have the potential to disrupt the efficient functioning of the market incentive framework. However, the Commission considers that the rules should require participants to provide a minimum level of ramp rate capability at all times, consistent with AEMO's ability to provide system security. See section 2.3. |
| MEU | If one generator uses an artificial ramp rate to remain dispatched out of merit order then another generator is constrained off even though it has offered a lower price and should be dispatched. This is inequitable and reflects that the current rules allow some generators to maximise their profitability at the expense of other generators (pp. | |

| Stakeholder | Comment | AEMC response |
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| | 21-22). | |
| Snowy Hydro | The market has experienced much lower energy and peak demand growth and in this environment it is to be expected that SRA spot accruals would be lower as has been seen. As a result the SRA proceeds are lower. It is completely inappropriate to therefore attribute lower SRA proceeds on rebidding of ramp rates (p. 12). | The Commission recognises that there are a range of factors that can affect counter-price flows and the value of SRAs. The Commission has not been persuaded that it would be appropriate to make a rule that requires generators to provide a greater minimum level of ramp rate capability that does not address the range of other factors that may contribute to the issues raised. See section 3.1.3. |
| Origin Energy | Origin note that declining demand and the oversupply of generation in the NEM has lead to low, flat wholesale prices with minimal regional price differentials. It therefore means that under current market conditions SRAs are likely to be low yielding which could help to explain any discount in their value as a hedging instrument (p. 3). | |
| **Dispatch inflexibility profiles** | | |
| Alinta Energy | Concerned fast start inflexibility profiles, including the minimum load and “T-times” entered into the bidding system do not actually reflect technical plant characteristics. Plant have been known to rebid and change their inflexibility profiles and minimum load when commercially beneficial. This has the effect of backing off other generation that would otherwise be dispatched. Fast start plant should not be able to arrange and change minimum load and T-times in a manner which distorts dispatch based on price and quantity. Supportive of a change that aligns all of the rules related to ramp rates and dispatch inflexibility profiles to ensure they at all times reflect the true | While acknowledging the AER's concerns in relation to inefficient outcomes caused by rebidding ramp rates and dispatch inflexibility profiles at times of network congestion, the Commission considers that there has been no compelling evidence produced to date that suggests that the costs to the market are likely to be material in the context of the NEM as a whole. While the final rule does not include any changes to the requirements in relation to dispatch inflexibility profiles, the Commission notes that the current requirements in the rules impose a degree of constraint on generators to make changes to time inflexibilities in their dispatch inflexibility |

| Stakeholder | Comment | AEMC response |
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| | characteristics of plant and cannot be manipulated for short-term commercial gain (p. 6). | profiles. The Commission considers that this has the potential to limit the extent to which generators can use dispatch inflexibility profiles to achieve commercial objectives at times of network congestion. |
| NGF | The AER has provided little information to support the change other than a desire for consistency in the treatment of "technical" parameters in offers. While the submission has focussed primarily on ramp rates, our arguments against ramp rates being a technical parameter can similarly be applied to dispatch inflexibility profiles (p. 1). | |
| GDF Suez | Dispatch inflexibility profiles should be set one day ahead and only changed for technical reasons. The AER would have the ability to ask generators to confirm / demonstrate the legitimacy of any dispatch inflexibility profile rebids provided within 24 hours of dispatch time (p. 3). | |

# D Summary of issues raised in submissions on the Draft Determination

| Stakeholder | Comment | AEMC response |
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| **AEMC more preferable draft rule** | | |
| Alinta Energy | The reference to special treatment in clause 3.1.4(3) of the NER means a rule specifically for the purpose of penalising or advantaging a form of technology only as a consequence of that technology being that technology. This is not how the AEMC has chosen to apply the concept in this instance. Suggesting that defining ramping capability based on technical characteristics offends the principle of technology neutrality is not correct. (pp. 1-2) | The Commission disagrees with this interpretation of the rules. A rule that requires generators to provide the maximum ramp rate that they can safely attain would impose higher minimum requirements on more flexible technologies. |
| Alinta Energy | The more preferable draft rule will leave spare minimum cost ramping for some units on the table, but will be set too high for others and will require derogations. It is difficult to support this as the most efficient approach. (p. 2) | The Commission considers that applying an approach that requires the lowest cost ramp rate for each individual generator in the NEM to be determined is likely to be administratively complex, create uncertainty, and may be subject to an extended negotiation and dispute resolution process. The Commission does not consider that such an approach would be in the interests of participants or consumers. |
| Hydro Tasmania | The draft rule of 1% exceeds AEMO's current requirement to maintain system security. This is likely to lead to several permanent derogations for large machines which cannot achieve 1%. In line with the AEMC stated principles of ramping being a commercial parameter, the regulatory amount being the minimum requirement, and | The Commission recognises that a minimum ramp rate requirement based on 1% of maximum capacity may impose inefficient costs if met on a continuous basis for some large thermal generators. However, the Commission considers that a minimum ramp rate requirement based on 0.5% would see a substantial reduction in minimum ramp |

| Stakeholder | Comment | AEMC response |
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| | competitive/technology neutrality, the minimum ramping capability should be no more than 0.5%. There would be no system security issue in Tasmania with the 0.5% proposal. (p. 2) | rates from current requirements for many generators in the NEM. The Commission would be concerned about consequent potential impacts on the efficiency of dispatch and system security. |
| Snowy Hydro | The draft rule exceeds AEMO's current requirement to maintain system security on a NEM-wide basis. In line with the AEMC stated principles of ramping being a commercial parameter, the regulatory amount being the minimum requirement, and competitive/technology neutrality, we advocate the minimum ramping capability should be no more than 0.5%. (p. 4) | |
| GDF Suez | The more preferred rule will impose relatively high ramping obligations on the largest generating units in the NEM. A requirement of 7 or 8 MW/minute could be difficult for some units to maintain. (p. 1) | The Commission recognises that a minimum ramp rate requirement based on 1% of maximum capacity may impose inefficient costs if met on a continuous basis for some large thermal generators. See section 4.3.2. |
| AGL | Although the preferred rule has the benefit of simplicity, some of AGL's generating plant (in particular Bayswater and Liddell) would be unable to sustain the required ramp rate even under normal conditions, without causing a substantial increase in maintenance costs and risking plant availability. In order to be practically workable and avoid the imposition of inefficient and avoidable maintenance costs, the revised rule would need to permit a generator to rely on an alternative, pre-agreed maximum ramp rate where technical grounds would frequently prevent it from attaining the proposed one per cent ramping rate. (pp. 1-2) | |

| Stakeholder | Comment | AEMC response |
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| Origin Energy | The more preferable rule does not recognise the nature of ramping profiles. A higher ramp rate may have commercial and technical implications for generating units. Commercially, a higher ramp rate may result in wear and tear costs and decrease the economic life of the asset. The generator would need to recover the increase in operating costs, diminishing productive efficiency. Technically, a higher ramp rate may risk the stable operation of the unit at higher levels. Assessing and determining what these parameters are for individual generating units is likely to increase the compliance burden for participants. This burden could be expected to remain over time as the generator performance changes over the economic life of the asset. The compliance burden would also extend to rebidding if the capacity of the generating unit is below the maximum capacity. (p. 4) | |
| EnergyAustralia | Draft rule will set minimum required ramp rates at or above the technical capability of some large units. The draft rule would increase the compliance burden due to the need to rebid with technical constraints. (pp. 1-2) | |
| Stanwell | Consider that for many of the larger thermal units in the NEM, 1% of maximum capacity may result in high cost wear and tear if provided consistently. If a significant number of these units were to apply for lower, more economically sustainable ramp rates to be applied it would dilute or remove the proposed benefit of the MPRC and create implicit technology differentials. (p. 3) | |

| Stakeholder | Comment | AEMC response |
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| GDF Suez | The preferable rule should be modified to set an upper limit on the minimum ramp rate obligation of 5 MW/minute per generating unit. For aggregate units in the NEM, this upper limit should be applied to each of the physical units within an aggregated unit. (p. 2) | The Commission notes the suggestion from GDF Suez. The Commission's more preferable final rule imposes a cap of 3 MW/minute. |
| GDF Suez | The capability for aggregate units to ramp up and down is a function of how many physical units are on line at the time. It is suggested that the minimum ramp rate obligation be made equal to one per cent of the maximum capacity of the physical units that are on line at any point in time. AEMO have real time data that confirms the on line status of all physical generating units. (p. 2) | The design of option 1 based the determination of minimum ramp rate requirements on 1% of maximum available capacity as a proxy for the number of units online. The Commission's reasons for not adopting option 1 are set in Box 4.1 of this final determination. |
| Origin Energy | Ramp rates should not be tied to the maximum capacity of generating plant but should rather reflect the number of units in service. This would minimise distortion and any added burden on these generating systems. (p. 5) | |
| AGL | Despite the preferred rule performing somewhat better on consistency and proportionality grounds than the existing regime, the mechanism to round up to the nearest whole MW/minute means that non-aggregated generators still bear a disproportionate burden of system ramp rate capability compared to equally sized aggregated unit stations. An alternative is to apply the existing minimum ramp rate provisions at the physical unit as opposed to the current registered unit level. This would avoid the substantial administrative effort | The Commission notes the suggestion from AGL. The Commission has adopted this approach in its final determination. |

| Stakeholder | Comment | AEMC response |
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| | associated with generators applying for, and AEMO assessing, technical derogations from the rule. It also performs better on equity grounds with consistent treatment of aggregated and non-aggregated units alike. (pp. 2-3) | |
| Snowy Hydro | Maximum generation capacity under schedule 3.1 is based on the assumption that all individual generators in the aggregate unit generator are generating at the same time. In the case of the Murray aggregated generator, it is extremely rare for all 14 units to be operating at the same time. With one unit operating, the draft rule would impose a minimum requirement of 15 MW/minute, whereas if the units were disaggregated then the minimum ramp rate may only be 1 MW/minute. This violates the competitive/neutrality principle. In some circumstances draft rule would be impossible to comply with. If a physical generating unit is shut down or not online there is no ramping requirement, the same should apply to individual units in an aggregate generator unit. The draft rule may create perverse incentives to disaggregate if the ramping requirement for an aggregated generator results in disproportionate risks and costs compared to operating in a disaggregation configuration. Disaggregation would result in more resources to dispatch generation plant. Minimum required ramp rates should be based on the number of physical units which are on line and synchronised and the maximum generation capacity of the physical unit. Snowy has confirmed with AEMO that relevant market data is available for this solution to be implemented. (pp. 2-3) | The Commission acknowledges Snowy Hydro's concerns in relation to the treatment of aggregated generating units. If individual participants are unable for physical or plant safety reasons to meet the minimum requirements, the final rule would retain the existing provisions that allow the generator to submit a ramp rate that is the maximum it can safely attain at the time and provide a brief, verifiable, and specific reason to AEMO as to why the ramp rate provided is below the minimum required. |

| Stakeholder | Comment | AEMC response |
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| **AER's proposed rule** | | |
| PIAC | Draft determination goes some way to addressing the problems highlighted in the rule change request. However, does not go far enough. While simplicity of operation is a desirable characteristic of regulation, it should not be prioritised above effectiveness. While determining the maximum ramp rate of a generator may involve a level of complexity, this is not sufficient reason to reject such an approach. AER would only have proposed such a rule if it was confident in its ability to enforce the requirement. (p. 3) | The Commission acknowledges PIAC's concerns but maintains that the AER's proposed rule would involve a greater burden of compliance and may be difficult to apply in practice. Further, the Commission considers that the proposed rule has the potential to create a disincentive to invest in flexible plant as it may disproportionately impact generators that are able to provide greater ramp rate capability. |
| MEU | The AEMC accepts the principle implicit in the AER proposed rule change that the current rules allow generators to use their ramp rates to cause the electricity market to be dispatched inefficiently by causing dispatch not to follow a merit order based on prices offered to the market. After accepting the principle in the AER proposal, the AEMC has reached a view that the AER proposal does not provide the best approach and that a more preferable rule would better achieve the NEO. (p.4) | While the Commission agrees that it would be desirable to minimise any such inefficiencies, in most cases, ramp rates represent only one contributing factor. However, in examining and consulting on the rule change request, the Commission has concluded that the existing provisions governing ramp rates risk distorting competitive market outcomes and investment signals. |
| **Design of the AEMC more preferable draft rule** | | |
| PIAC | The draft determination does not explain how the maximum capacity of a generator would be determined in order for the 1% to be derived. The AEMC has not stated whether the maximum capacity will be set permanently or re-evaluated periodically. (p. 3) | The maximum capacity is specified to AEMO as part of the bid and offer validation data in accordance with schedule 3.1 of the NER. Participants are required to provide six week notice of any changes to bid and offer validation data. |

| Stakeholder | Comment | AEMC response |
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| MEU | A higher minimum ramp rate requirement than 1% could be made. A generator, if it has a technical reason for not being able to comply with the minimum ramp rate, could seek an exemption, as well as have the opportunity to bid lower ramp rates than the minimum if it has sound technical reasons for needing to do so. (p.12) | If individual participants are unable for physical or plant safety reasons to meet the minimum requirements, the final rule would retain the existing provisions that allow the generator to submit a ramp rate that is the maximum it can safely attain and provide a brief, verifiable, and specific reason to AEMO as to why the ramp rate provided is below the minimum required. However, the Commission considers that imposing a minimum ramp rate requirement that is significantly above 1% would likely require a large number of participants to provide such reasons on a frequent basis which would likely increase compliance costs. |
| **Issues raised by the rule change request** | | |
| AER | Analysis shows the AEMC's preferred rule would increase minimum available aggregate ramp rates in New South Wales, Victoria and Queensland. However, 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. Generators may have more opportunity to selectively reduce ramp rates in South Australia and Tasmania. South Australia has the highest penetration of intermittent renewables and it is not uncommon for only three or four conventional thermal units to be operating in the region. If conditions are right, generators may offer lower minimum ramp rates than currently apply, thereby potentially increasing volatility and/or requiring AEMO to issue directions. (p.1) | The Commission acknowledges the reduction in aggregate ramp rate capability in a number of NEM regions that would have resulted under the more preferable draft rule. This is in contrast to the more preferable final rule which will see an overall increase in aggregate ramp rate capability in all regions of the NEM. |

| Stakeholder | Comment | AEMC response |
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| AGL | AGL's own analysis suggests that there would be a negative change in overall ramping capability in South Australia and Tasmania. Given the high proportion of wind in South Australia, AGL would be cautious about supporting a rule change that would reduce the ramping capability in that region. The preferred rule would lead to an increase in ramping capability in regions which are least likely to experience system security issues. (p. 2) | |
| AEMO | The proposed rule has the potential to reduce the available ramp rate capability in South Australia in some specific circumstances. In these circumstances, AEMO is more likely to need to direct under the proposed rule compared to both the current rules and the AER's proposal. These are:<br><br>• At times of high wind generation where a reduced amount of synchronous generation is in service, exposing South Australia to disruption of supply if the Heywood interconnector were to trip.<br><br>• Hot water switching at approximately 23:30 hrs each day, causing the interconnection from Victoria and available thermal plant to be operated for longer periods at their capacities.<br><br>The draft rule would reduce the available ramping capability under these conditions to a greater extent than the originally proposed rule. (pp. 2-3) | |

| Stakeholder | Comment | AEMC response |
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| **Rule commencement date** | | |
| Hydro Tasmania | The draft rule may cause a significant reduction in transmission access for some plant thereby significantly reducing the capability of plant to hedge sold forward contracts. The rule commencement date must reflect and recognise this increase hedge contract risk and have an appropriate transitional notice period to allow participants to adjust their risk profiles. Commencement should be no earlier than 1 January 2017. (p. 2) | The Commission has determined to commence the change to the NER from 1 July 2016. This should provide a sufficient period of transition for participants to manage their forward hedge contract position to accommodate the change in minimum ramp rate requirements for aggregated facilities. |
| Snowy Hydro | The draft rule has the potential to materially affect transmission access, thereby significantly reducing the capability of plant to hedge sold forward contracts. Based on the sale of contracts out to 3 years, the commencement date should be no earlier than 1 January 2017 to allow market participants to manage their risks. (pp. 4-5) | |
| **Dispatch inflexibility profiles** | | |
| Alinta Energy | The issue of inflexibility profiles has not been given the attention required and that the case for ensuring minimum load and 'T-times' entered into the bidding system reflect technical characteristics is clear cut. If an inflexibility profile can be changed at will it seems, prima facie, to defy the very purpose of its existence. (p. 3) | While the final rule does not include any changes to the requirements in relation to dispatch inflexibility profiles, the Commission notes that the current requirements in the rules impose a degree of constraint on generators to make changes to time inflexibilities in their dispatch inflexibility profiles. This has the potential to limit the extent to which generators can use dispatch inflexibility profiles to achieve commercial objectives at times of network congestion. |

# E Summary of issues raised in submissions on the Options Paper

| Stakeholder | Comment | AEMC response |
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| **Option 1** | | |
| EnergyAustralia | Option 1 should be implemented with maximum capacity used in place of available capacity. Option 1 allows for dynamically changing compliance targets which may increase costs to regulate and the likelihood of compliance breaches by generators. The difference between use of available capacity over maximum capacity is not significant enough to justify the added complexity. | The Commission recognises the additional complexity of using available capacity to determine minimum ramp rate requirements. The more preferable final rule does not use available capacity as a determinant for minimum ramp rates. |
| Snowy Hydro | Option 1 is workable even though it is a proxy for units online in an aggregate group generator. Reductions in ramp rate capability in QLD, TAS and SA should not be an impediment to adoption this option. | The Commission notes that such a reduction in ramp rate capability may still have a negative impact on the efficiency of dispatch outcomes. |
| SA Government | Has concerns with option 1 in South Australia. With substantial wind energy investment having attracted 41 per cent of the nation's installed capacity, any reduction in ramping capability results in greater price volatility as wind generation can significantly reduce the commitment of conventional thermal generation. | The Commission notes the concerns raised with the potential reduction in aggregate ramp rate capability in some NEM regions. |
| **Option 2** | | |
| Stanwell | Option 2 is likely to create an onerous burden on large plant with a large number of aggregated units. | Analysis undertaken using AEMO data suggests that individual generators should be able to meet |

| Stakeholder | Comment | AEMC response |
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| Snowy Hydro | Option 2 imposes an onerous burden on aggregated generators when only one or a few units are online. Option 2 would create perverse incentives to disaggregate since the ramping requirement for an aggregate generator with less than the maximum number of physical units online results in higher costs than operating in a disaggregated configuration. | their minimum requirements under the more preferable final rule. However, if individual participants are unable at any time to meet the minimum requirements for physical or plant safety reasons, the final rule would retain the existing provisions that allow the generator to submit a ramp rate that is the maximum it can safely attain and provide a brief, verifiable, and specific reason to AEMO as to why the ramp rate provided is below the minimum required. |
| MEU | Applying the lowest common denominator ramp rate is not in the interests of consumers as there are other tools available to address the concerns of technology driven low ramp rate generation. The most obvious of these is to allow a generator to seek exemption from the defined ramp rate and be granted a lower ramp rate dependent on its technology. This approach to exemption is already available for some generators. | |
| AEMO | For many of the generating units that are likely to have higher minimum ramp rates, historical observations suggest that the capability for aggregated units to ramp up and down is not a function of how many physical units are online at the time. AEMO concludes that there is not a strong correlation between unit output and low ramp rates, indicating that the number of individual units in service has not been a significant factor in lower ramp rates offered by participants. This suggests that the existing provisions that allows participants to offer ramp rates below the minimum specified in the rules provides sufficient protections to participants for technical reasons. | |

| Stakeholder | Comment | AEMC response |
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| MEU | Option 2 is the least worst of the options as it provides a net improvement in aggregate ramp rate capability for every region whereas the other AEMC options result in reductions in aggregate ramp rates in some regions which is not in the long term interests of consumers. | Given the additional level of minimum ramp rate capability, the more preferable final rule would extend the set of feasible dispatch solutions, and so is likely to improve the efficiency of dispatch outcomes. |
| SA Government | Supports option 2 as the preferred approach. This option represents an incremental improvement from the existing arrangements and increases the minimum ramp rate capabilities for aggregated generators in all regions. | |
| **Rule commencement date** | | |
| Snowy Hydro | The rule commencement date must reflect and recognise the increased hedge contract risk and have an appropriate transitional notice period of 3 years. | The Commission has determined to commence the change to the NER from 1 July 2016. This should provide a sufficient period of transition for participants to manage their forward hedge contract position to accommodate the change in minimum ramp rate requirements for aggregated facilities. |