RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Generator ramp rates and dispatch inflexibility in bidding) Rule 2014

Rule Proponent

Australian Energy Regulator

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About the AEMC

The Council of Australian Governments (COAG), through its then Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. In June 2011, COAG established the Standing Council on Energy and Resources (SCER) to replace the MCE. The AEMC has two main functions. We make and amend the national electricity, gas and energy retail rules, and we conduct independent reviews of the energy markets for the SCER.

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Executive Summary

This consultation paper has been prepared by the Australian Energy Market Commission (AEMC or Commission) to facilitate public consultation on a rule change request submitted by the Australian Energy Regulator (AER) proposing a requirement for generator ramp rates and dispatch inflexibility profiles to reflect the technical capabilities of generating plant.

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

The AER considers that ramp rates and dispatch inflexibility profiles are on occasion used by generators to achieve commercial objectives and that this can be harmful both in terms of inefficient market outcomes and on the ability for the Australian Energy Market Operator (AEMO) to efficiently manage system security.

The AER's proposed rule would require generators to submit ramp rates and dispatch inflexibility profiles that reflect the technical capabilities of generating plant at all times.

The Commission's assessment of the rule change request will consider both the nature and extent of the costs identified by the AER and the practicality and merits of the AER's proposed rule.

In consideration of a framework to assess the rule change request, the Commission has made a distinction between those costs proposed by the AER that may be more directly attributable to the rebidding of ramp rates under constraint conditions and those costs where the rebidding of ramp rates may be a contributing or supporting factor but which is not necessarily the principal or underlying cause. This distinction is primarily driven by the priority afforded to satisfying ramp rates and dispatch inflexibility profiles submitted by generators in the market dispatch process.

The Commission also intends to assess the practicality and merits of the AER's proposed rule including a consideration of how ramp rates would be determined and enforced and any benefits that the current rules provide to generators in the management of dispatch risk.

In the paper, the Commission sets out its view that a trade-off exists between ramp rate capability and costs incurred, which may make it difficult to define ramp rates as a purely technical parameter. The Commission is therefore inviting views on a wider range of potential options to address the identified issues.

In particular, the Commission is interested in whether it is possible to provide incentives such that ramp rate capability is provided at times when this would be valued by the market. However, the Commission is also conscious of the need to consider the risk that altered incentives, or any new technical or regulatory requirements, may lead generators to pursue similar commercial objectives through different means.

This paper has been prepared to facilitate public consultation on the rule change request. Stakeholders are encouraged to provide any submissions by 27 March 2014. Further details can be found on the AEMC's website.

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1 Introduction

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 for generator ramp rates and dispatch inflexibility profiles to reflect the technical capabilities of generating plant.

The rule change request is intended to address alleged inefficient market outcomes resulting from the incentives generators have to rebid ramp rates to low levels at times of network constraints. The AER proposes that this be achieved by requiring generators to provide ramp rates that at all times reflect their technical capabilities. The AER considers that this would essentially require participants to submit a ramp rate that is the maximum the plant can safely attain at the time.

The AER also notes that dispatch inflexibility profiles can be used by participants with fast-start plant to achieve commercial objectives and that this also results in market inefficiencies. The AER considers that this 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 The rule change process

On 13 February 2014, the Commission published a notice under section 95 of the National Electricity Law (NEL) setting out its decision to commence the rule change process in relation to this rule change request.

Due to the complex nature of this rule change request and the potential variations in stakeholder views, the Commission has determined to extend some of the standard periods under the NEL, including the period for consultation on the rule change request. Consequently, on 13 February 2014 the Commission also published a notice under section 107 of the NEL extending the period for publication of the draft determination until 28 August 2014.

1.3 This consultation paper

This consultation paper has been prepared to facilitate public consultation on the rule change request, and to seek stakeholder submissions on the rule change request.

This paper:

- sets out a summary of, and a background to, the rule change request submitted by the AER;
- identifies a number of questions and issues to facilitate the consultation on this rule change request; and
- outlines the process for making submissions.

2 Background

This chapter provides background to the rule change request and describes the issues that the rule change request is intended to address.

2.1 The design of the market and generator bidding

A principal function of the National Electricity Market (NEM) is the coordination of the output of generating plant to meet customer demand. Generators are prioritised in the dispatch order based on the bids they submit to the Australian Energy Market Operator (AEMO). Generators with the lowest bids are dispatched first with progressively higher bids dispatched in order to meet increases in demand, subject to certain constraints. In this fashion, an economically optimal dispatch arrangement of generation is achieved.

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

- Ramp rates - The National Electricity Rules (NER) currently requires scheduled generators to specify for each of the half-hour trading intervals in a day, an up ramp rate and a down ramp rate. Generators have the ability to rebid their ramp rates during a 5-minute dispatch interval with effect from the next dispatch interval. Generators must specify a ramp rate that is 3 MW/minute or higher (or 3 per cent of maximum capacity for generators below 100 MW) unless there is a technical limitation on their plant.

- Dispatch inflexibility profiles - The NER currently provides fast start generators with the discretion to include dispatch inflexibility profiles as part of their dispatch offer. 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.[1]

Generator ramp rates and dispatch inflexibility profiles are both parameters of generator bids which AEMO must factor into the determination of the optimal economic dispatch arrangement.

2.2 Network congestion and dispatch risk

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 bids.

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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 thirty minutes of receiving an instruction from AEMO.

To manage network flows in the NEM, AEMO utilises generator bids together with constraint equations (which represent network capacity limits) through the NEM dispatch engine (NEMDE) to determine the optimal economic dispatch of generation to meet customer demand, subject to ensuring the system is secure. This may mean that some generators are dispatched out of merit order, with some higher priced capacity dispatched in preference to lower priced capacity. All generators that are dispatched receive the regional energy price.

Dispatch is calculated every five minutes using NEMDE. Changes in the capacity ratings of network lines, due to ambient temperature fluctuations and weather events or technical limitations of generating plant, can have a corresponding influence on the merit order of dispatched generation with some generators constrained off in order to manage network flows.

As such, generators in the NEM are exposed to dispatch risk as a consequence of congestion in the transmission network. Therefore, 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 vary different parameters in their bids to reduce the risk of being constrained.

This form of rebidding is undertaken by generators to influence the outcomes that NEMDE will choose to manage network congestion. The most commonly discussed example of the management of dispatch risk is the rebidding of price and volume. Generators that are forecast to be constrained have an incentive to rebid capacity into different price bands in order to limit the impact of network congestion on their dispatch. For example, as NEMDE prioritises the dispatch of generators with the lowest bids, generators that are likely to be constrained off may rebid capacity into negative price bands to reduce the extent to which their dispatch levels will be decreased.

Similar to the management of dispatch risk through the rebidding of price and volume, generators can rebid to change their ramp rates or dispatch inflexibility profiles to limit the extent to which their existing output levels can be increased or decreased. For example, generators that are likely to be constrained off may 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.

2.3 The AER's previous rule change request

In 2009, the AEMC made a rule in relation to a request received from the AER, which placed requirements on generators regarding certain technical aspects of their bids.[2] The rule placed restrictions on ramp rates, market ancillary services offers, and dispatch inflexibilities that generators could specify in their bids. The rule also provided powers to the AER to seek substantiating information from generators to verify the accuracy of their bids.

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

2.3.1 Background to the rule change request and final determination

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 AER also provided examples where generators had rebid market ancillary service offers or dispatch inflexibility profiles to limit the rate at which their dispatch targets could be reduced in response to binding network constraints.

The Commission's final determination on the AER's previous rule change request imposed:

- a minimum ramp rate of 3 MW/minute except where it could be demonstrated to NEMMCO that a lower ramp rate is required for technical or safety reasons. Where a generator has a nameplate capacity of less than 100 MW, the minimum ramp rate to apply is 3 per cent of maximum capacity. The ramp rate specified must be no more than the maximum ramp rate that an item of equipment is capable of achieving in normal circumstances, as specified by the generator in accordance with schedule 3.1 of the NER;

- a requirement for market ancillary service parameters bid by generators to reflect the technical capability of the generator's plant;[3] and

- a requirement that generators declare themselves "inflexible" only when plant technical constraints justify such a declaration.

Under the NEL, the AER's enforcement role and powers allow it to investigate and take action against a possible breach of the NER. The AEMC determined that the requirement for generators to meet a minimum ramp rate of 3 MW/minute be a civil penalty provision. 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.

2.3.2 The Commission's reasoning

Prior to the Commission's final determination, the only restriction in the NER on the ability of scheduled generators to rebid either ramp rates and market ancillary services or declare themselves inflexible was that offers or rebids must be made in good faith.[4]

3 Prior to the AEMC final determination in January 2009, generators were able to rebid market ancillary service parameters to "trap" dispatch levels at close to maximum output. Further detail on the bidding of market ancillary services is provided in Appendix A.

The AER's previous 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 economically 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's proposed minimum ramp rate of 3 MW/minute was based on an analysis of generator bids prior to the time of the rule change request which showed that all except for a handful of generators bid at 3 MW/minute or greater most of the time. The AER considered that, based on past ramp rate bidding practices, a level of 3 MW/minute minimum ramp rate would be sufficient for most generators. The AER also 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.

In order to avoid placing a disproportionate burden on smaller generators, 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.

Further discussion of the AER's previous rule change request is provided in Appendix A.

2.4 Current rules

Since the making of the rule discussed above, certain elements of generators' bids are required by the NER to reflect the technical characteristics of their plant such as those related to ancillary service parameters or when a generator declares its plant inflexible and is unable to follow dispatch instructions. The AER notes that the rules do not have similar requirements in relation to ramp rates or when a generator commits its plant using a dispatch inflexibility profile.

Table 2.1 sets out the current requirements in the NER relating to the treatment of technical aspects of generators' bids. The table includes the current requirements relating to the content of bids and the powers that the AER has, both under the NER and the NEL, to enforce these requirements and seek substantiating information to verify generator bids.

4 Clause 3.8.22A of the NER provides that generators must have an intention to honour their bids and offers unless the material conditions and circumstances upon which the original offer was based change.

Table 2.1 Current treatment of technical aspects in the NER

Technical aspect	Current limitations in NER	AER enforcement powers	NER clause
Ramp rates	At least 3 MW/minute (or 3 per cent of maximum capacity for generators below 100 MW) unless technical limitation, no greater than maximum capability of generator	NER: AER may seek substantiating information from generators NEL: Civil penalty provision applies - AER may investigate potential breach	3.8.3A
Market ancillary services	Must reflect technical capability	NER: No specific clause to seek substantiating information NEL: Civil penalty provision applies - AER may investigate potential breach	3.8.7A
Dispatch inflexibilities due to abnormal conditions	Must reflect technical capability	NER: Generator must provide reasons and AER may seek substantiating information from generators NEL: Civil penalty provision applies - AER may investigate potential breach	3.8.19
Dispatch inflexibility profiles	No specific restrictions	No specific powers	3.8.19(d)

In addition to the requirements set out in table 2.1 above, schedule 3.1 of the NER requires that generators submit maximum ramp rates to AEMO at least six weeks prior to participating in the NEM.[5] Clause 3.8.4(c) of the NER also requires generators to submit information regarding any constraints on ramp rates two days ahead of each trading day.

Prior to the commencement of each dispatch period generators must submit dispatch offers to AEMO. In accordance with clause 3.8.6(a) generators are required to specify for each of the 48 trading intervals in the relevant day an up ramp rate and a down ramp rate.

5 Maximum ramp rate is defined in the NER as the maximum ramp rate that an item of equipment is capable of achieving in normal circumstances. This may be as specified by the manufacturer or as independently certified from time to time to reflect changes in the physical capabilities of the equipment.

3 Summary of the rule change request

This chapter provides a summary of the AER's rule change request.

3.1 Overview

The AER’s rule change request seeks to address the ability of generators to pursue commercial objectives through the rebidding of ramp rates and changes to dispatch inflexibility profiles.

The AER considers that generator rebidding at times of network constraints has become increasingly prevalent over the last three years and that the previous change made to the NER in 2009 has not been sufficient in many instances. 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.

The AER proposes to align all of the rules related to ramp rates and dispatch inflexibility profiles to ensure they at all times reflect the true characteristics of plant and cannot be manipulated for short-term commercial gain. The AER asserts 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 scheduled and semi-scheduled generators, scheduled network services and scheduled loads.

3.2 Ramp rates

Clause 3.8.3A of the NER currently requires scheduled generators to specify for each of the trading intervals in a day, an up ramp rate and a down ramp rate. Generators have the ability to rebid their ramp rates during a dispatch interval with effect from the next dispatch interval. Generators must specify a ramp rate that is 3 MW/minute or higher (or 3 per cent of maximum capacity for generators below 100 MW) unless there is a technical limitation on their plant.

Through this rule change request, the AER seeks to place a greater restriction on generator ramp rates by requiring 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 at that time. If a generator submits a ramp rate lower than the maximum it is technically capable of achieving then it would be required to accompany the bid with a brief, verifiable, and specific reason relating to the relevant technical limitation on their generating plant.

3.3 Dispatch inflexibility profiles

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

The AER considers that the current rules are imprecise and that generators can change their dispatch inflexibility profiles through the rebidding process for any reason, and may do so for commercial advantage. Through this rule change request, the AER seeks to require fast start generators to submit a dispatch inflexibility profile that reflects the technical limitations of their plant.

3.4 Compliance

In July 2001, the National Electricity Code Administrator published a guideline on the disclosure of information by generators at times of rebidding. This guideline set out the detail that must be contained in rebid reasons. From 1 July 2005, preparation of the guideline has been the responsibility of the AER. In response to the changes to the NER made in January 2009, arising from the AER's previous rule change request on generator ramp rates, the AER replaced this guideline with the "Rebidding and Technical Parameters Guideline".[6] This updated guideline was prepared to provide information to market participants on:

- the AER's interpretation of the provisions made under the changes to the NER and how the AER will monitor and enforce their compliance;
- the detail that must be contained in a rebid reason submitted to AEMO; and
- the additional information that may be sought by the AER to verify and substantiate the brief, verifiable and specific reason that must be provided with bids and rebids.

Given the variable and technical nature of ramp rates, the AER notes that concerns may be raised with respect to how changes to the NER arising from the current rule change request may be enforced. To provide further clarity on how the proposed rule would operate in practice, and how the AER would enforce it, the AER would amend its Rebidding and Technical Parameters Guideline.[7]

6 This guideline is available on the AER website.

7 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.

4 Assessment Framework

This chapter sets out the proposed framework for assessing the rule change request.

4.1 NEO assessment

The Commission's assessment of this rule change request must consider whether the proposed rule promotes the National Electricity Objective (NEO) as set out under section 7 of the National Electricity Law (NEL) as follows:

> "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."

Based on a preliminary assessment of this rule change request, the Commission considers that the relevant aspects of the NEO for further consideration are the efficient operation of electricity services with respect to the reliability and security of the national electricity system and the price of supply of electricity.

As part of its rule change request, the AER has provided a perspective on how the proposed rule would promote the NEO. The AER's views are broadly consistent with the Commission's intended focus of assessment. The AER considers that the proposed rule will contribute to the promotion of the NEO through the following means:[8]

- The quicker and more flexible alleviation of network constraints, thereby improving the safety, reliability and security of the supply of electricity and the national electricity system. Requiring generators to bid the maximum ramp rate that they are technically capable of achieving at the time would enable constraints in the network to be alleviated more quickly, thereby enhancing system security.
- A reduction of the occurrence of counter-price flows across interconnectors, thereby reducing the prices paid by consumers by supporting competition between regions and reducing transmission network charges.[9]
- A reduction in wholesale spot price volatility, thereby alleviating upwards pressure on the price of hedge contracts and a reduction in the extent to which these additional costs flow through to retail tariffs and the prices paid by consumers.

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8 AER, *Rule change request – Requirement for ramp rates and dispatch inflexibility profiles to reflect technical capabilities*, 21 August 2013, pp. 18-19.

9 A further discussion of counter-price flows is provided in Chapter 5.

- Avoiding the need to otherwise address the problem through short-term inefficient investment in transmission infrastructure to alleviate network congestion, thereby reducing the costs that flow through to consumers.

4.2 Scope of the assessment framework

Assessment of the AER's rule change request will necessarily involve a consideration of the costs and benefits of the rebidding of ramp rates and changes to dispatch inflexibility profiles. It is important to note that ramp rates and dispatch inflexibility profiles are only two parameters that a generator may change in its bids. Addressing the AER's identified issue of rebidding ramp rates and changing dispatch inflexibility profiles would not entirely remove the ability of generators to engage in rebidding under constraint conditions to achieve commercial objectives. For example, in a number of circumstances, a generator may achieve similar commercial outcomes through rebidding generation volume into negative price bands.

This consultation paper makes a distinction between those costs identified by the AER that we consider may be more directly attributable to the rebidding of ramp rates under constraint conditions and those costs where the rebidding of ramp rates may be a contributing or supporting factor but which is not necessarily the principal or underlying cause.

As is discussed further in this consultation paper, the nature of the costs can change depending on whether rebidding is undertaken through ramp rates and changes to dispatch inflexibility profiles, or through other forms of rebidding.

For example, rebidding ramp rates and changes to dispatch inflexibility profiles may be the primary driver of a reduced ability for AEMO to efficiently manage system security. This is in contrast to other costs raised by the AER such as increased price volatility and reduced price predictability, which may be driven by the rebidding of price and volume or the rebidding of ramp rates, or both.

All of the costs raised in the AER’s rule change request are discussed further in Chapter 5.

While an assessment of the AER's rule change request will necessarily consider all of these costs, we consider that the assessment should place a greater weight on the costs that may be more specifically attributed to the issue of rebidding ramp rates and changes to dispatch inflexibility profiles. This distinction has been made to focus the assessment framework in order to determine the extent to which justification exists for making the AER's proposed rule.

In addition, all of the above costs must be weighed against the potential benefits that generators may obtain from an ability to manage the risk of not being dispatched, including the ability to meet their contractual obligations under hedge contract arrangements and to obtain revenue certainty for access to third-party financing to underpin efficient investments. These issues are explored further in Chapter 6.

South Australian Government rule change request

The Commission has recently received a rule change request from the South Australian Government relating to the good faith bidding provisions in the NER. These provisions cover all forms of bids and rebids made by generators.

In support of this rule change request, the South Australian Government has suggested that inefficient market outcomes result from generators engaging in rebidding at times of network constraints. As such, the forthcoming consultation on the South Australian Government's rule change request will represent an opportunity to assess potential inefficient costs associated with all forms of generator bidding and rebidding. This may include those costs where the rebidding of ramp rates may be a contributing or supporting factor but which is not necessarily the principal or underlying cause.

5 Issues raised by the AER

This chapter discusses the issues raised in the AER's rule change request and sets out a number of questions to guide stakeholders in responding to this consultation paper.

The AER has stated that there are significant costs associated with the rebidding of ramp rates and changes to dispatch inflexibility profiles under constraint conditions to achieve commercial objectives. As discussed in Chapter 4, we consider that these costs can be categorised into those that may be more specifically attributed to the issue of rebidding ramp rates and changes to dispatch inflexibility profiles, including:

- impacts on the ability of AEMO to manage system security; and
- increases in the prevalence of counter-price flows on interconnectors;

and those where the rebidding of ramp rates and changes to dispatch inflexibility profiles may be a contributing or supporting factor but which are not necessarily the principal or underlying cause, including:

- productive efficiency losses from high cost generation being dispatched in place of low cost generation;
- higher risk management costs due to greater levels of spot price volatility and unpredictability;
- a distortion of efficient price signals for investment; and
- a reduction in the effectiveness of interconnectors and the value of Settlement Residue Auction (SRA) units for the management of inter-regional price risk.

These issues are outlined and discussed further below and are provided for guidance. Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper including the proposed framework.

5.1 System security and counter-price flows

This section provides a discussion of the issues raised by the AER that we consider may be more directly attributable to the rebidding of ramp rates and changes to dispatch inflexibility profiles, including the management of system security and stability and counter-price flows between NEM regions.

5.1.1 Management of system security and stability

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 reduces the flexibility and efficiency with which AEMO can manage the stability and security of the electricity system. The AER considers that this is primarily driven by the priority afforded to ramp rates and dispatch inflexibility profiles when the optimal economic dispatch is calculated by NEMDE.

In order to manage network congestion, NEMDE prioritises different technical aspects of generators and the network. Ramp rates and dispatch inflexibility profiles are considered to be higher priority constraint types than network limits. This is because AEMO is dependent on what generators submit and for which bids can vary across a wide range. The AER considers that the priority afforded to satisfy generator ramp rates and dispatch inflexibility profiles may compromise the security of the national electricity system in instances where network constraint conditions have been violated.

Importantly, NEMDE will give priority to network limits over the rebidding of price and volume but not over the rebidding of ramp rates and dispatch inflexibility profiles. Therefore, a potential distinction exists between the impact that the rebidding of ramp rates has on the ability for AEMO to manage system security compared to the impact of the rebidding of price and volume. Box 5.1 provides a discussion of the priority afforded by NEMDE to different technical aspects of generators and the network in the calculation of the optimal economic dispatch.

AEMO may step in to override generator bids 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, the rebidding of ramp rates by generators under constraint conditions may compromise the ability for AEMO to determine an economically efficient dispatch arrangement while maintaining system security.

Question 1

(a) Does the current minimum required ramp rate of 3 MW/minute hinder AEMO's ability to determine an economically efficient dispatch arrangement while maintaining system security?

(b) If so, would the AER's proposed rule improve the economic efficiency of the dispatch process in this regard?

(c) What evidence is there that system security has been compromised by ramp rate limitations?

Box 5.1 Prioritising technical aspects of generators and the network in the dispatch process

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

Each technical aspect is assigned a constraint violation penalty (CVP) which represents the incremental cost incurred if a constraint equation that represents the technical aspect is violated. 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 5.1 shows CVPs for a number of different technical aspects. There are a total of 47 different CVPs applied to various technical aspects of the system which are used by NEMDE to determine the optimal dispatch. Satisfactory and secure network limits have lower CVPs than ramp rates and dispatch inflexibility profiles. As such, NEMDE will place higher priority on satisfying generator ramp rates and dispatch inflexibility profiles than on maintaining system security in the determination of the optimal economic dispatch.

NEMDE calculates the optimal economic dispatch by assigning a cost to each technical aspect according to its CVP. All CVPs are set at values above the market price cap (MPC) to ensure that all available energy is used prior to violating technical aspects of generators and the network. CVPs are represented as a multiplier of the MPC. In table 5.1, NEMDE would allocate a cost of approximately $15 million/MWh (1,155 x MPC $13,100) to ramp rates and approximately $458,000/MWh (35 x MPC $13,100) to secure network limits.

Table 5.1 Technical aspects of the system and constraint violation penalties

Technical aspect	CVP	Comment
Ramp rates	1155	NEMDE takes as given as it cannot second guess generator capability
Dispatch inflexibility profiles	1130	NEMDE cannot second guess generator capability
Minimum and fixed loading level	380	NEMDE cannot second guess generator capability
Satisfactory network limit	360	Beyond this may damage equipment
Secure network limit	35	Beyond this may damage equipment following a credible contingency
Negative Residue Management (clamping)	2	May be increased to stop accumulation of negative residues, subject to maintaining power system security

5.1.2 Counter-price flows between NEM regions

The AER considers that the ability to rebid ramp rates and make changes to dispatch inflexibility profiles under constraint conditions can result in counter-price flows on interconnectors. It considers that this reduces the effectiveness of interconnectors and increases network charges to consumers.

Under conditions of network congestion, generators may be constrained off to reduce localised excess supply. A generator that rebids ramp rates to low levels under these constraint conditions, can cause NEMDE to force other generators to reduce output in order to manage the network congestion. If these other generators are situated on the other side of an interconnector then this may result in flows on the interconnector from a high-priced region to a low-priced region. Generally this occurs where the generator engaged in the rebidding is close to an interconnector and congestion arises between that generator and the regional reference node (RRN). The mechanics of this effect are illustrated in Box 5.2.

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.

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.

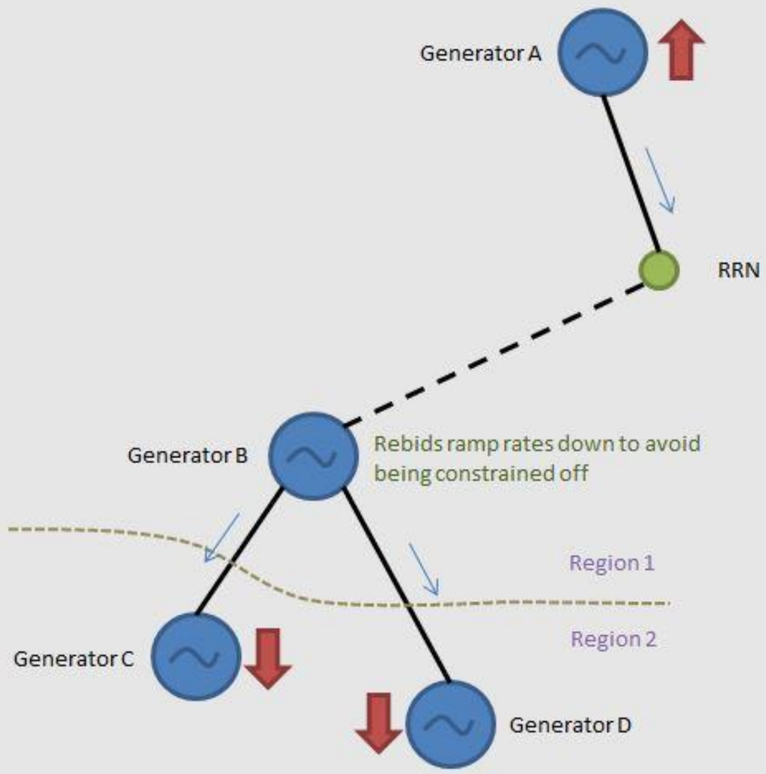
Counter-price flows may also occur from generators engaging in other forms of rebidding under constraint conditions, such as the rebidding of price and volume. However, the costs associated with the rebidding of ramp rates have the potential to be more substantial. This is because AEMO will override generator bids, including rebidding capacity into negative price bands, in order to limit counter-price flow but will ensure that power system security takes precedence, including the management of generator ramp rates and dispatch inflexibility profiles. Ramp rates and dispatch inflexibility profiles are considered to be higher priority constraint types than the management of negative inter-regional settlement residues through clamping. This is explained further in Box 5.2.

Box 5.2 Counter-price flows arising from generator rebidding under constraint conditions

Figure 5.1 illustrates how the rebidding of ramp rates at times of network constraints can cause counter-price flows on an interconnector.

As a result of congestion on the network line between generator B and the RRN, supply from generator B to the RRN is reduced and the dispatch levels from generator A are increased to compensate. Generator A is constrained on and rebids capacity to the MPC, setting the regional energy price. In response, generator B attempts to maximise its exposure to the regional energy price and rebids to reduce the rate at which its dispatch levels can be ramped down. This forces generators C and D to be ramped down instead in order that supply and demand are balanced. Flow is forced away from generator B in region 1 with a high regional energy price towards generators C and D in region 2 with a lower regional energy price.

Figure 5.1 Inter-regional effects of rebidding ramp rates in a congested network



AEMO will override generator bids, including rebidding of price and volume, in order to limit flow but will ensure that power system security takes precedence, including the management of generator ramp rates and dispatch inflexibility profiles. This is evidenced with reference to table 5.1 above, which shows a CVP for negative residue management of 2 compared to a CVP for ramp rates of 1155. NEMDE views the cost associated with limiting negative settlement residues on interconnectors as $26,200/MWh (2 x MPC $13,100). NEMDE will override price and volume bids with a maximum cost of -$1,000/MWh (market floor price) but will not override ramp rates with an approximate cost of $15 million/MWh (1155 x MPC $13,100).

Therefore, a generator that engages in the rebidding of ramp rates at times of network congestion is unlikely to be constrained off in order to limit counter-price flows, but may be constrained off if they engage in rebidding of price and volume.

Table 5.2 sets out analysis provided by the AER on the quantity of negative settlement residues that have accrued on different interconnectors due to counter-price flows. The total negative settlement residues are a sum of all instances of counter-price flow where the accrued settlement residue at the time was greater than $150,000 and have been included in the calculation irrespective of their cause, ie irrespective of whether the counter-price flow was due to generators rebidding ramp rates or dispatch inflexibility profiles under constraint conditions.

Table 5.2 Accumulation of negative settlement residues from counter-price flows

Interconnector	Period	Negative Settlement Residue
VIC → NSW	Since February 2010	$25.8m
NSW → VIC	Since December 2009	$8.9m
QLD → NSW	Since September 2011	$14.5m

Question 2

(a) Do you agree with the AER's assessment of the costs associated with counter-price flows?

(b) To what extent is generator rebidding a cause of counter-price flows on interconnectors? Is this primarily due to generators' ramp rates or other forms of bidding behaviour?

5.2 Productive efficiency losses and risk management costs

This section provides a discussion of the issues raised by the AER where we consider that the rebidding of ramp rates and changes to dispatch inflexibility profiles to achieve commercial objectives may be a contributing or supporting factor but which is not the only cause.

5.2.1 Productive efficiency losses

The AER asserts 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. 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 price and volume.

NEMDE determines the most economically optimal mix of plant to meet demand given the limitations placed by congestion in the network. Generators may change their bids to influence the outcomes that NEMDE chooses to achieve the optimal mix 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.

However, this outcome may be predicated on an assumption that a generator's bids are representative of their economic costs. The economic cost of a generator may also take into account a range of factors that are not necessarily incorporated in generator bids, such as the opportunity costs that are associated with undertaking plant maintenance.

In addition, generators may be able to achieve the same outcome through rebidding dispatch volume into lower price bands. Therefore, the AER's proposed rule to require generators to submit ramp rates that reflect the technical capabilities of generating plant may not necessarily address the issue of potential productive efficiency losses. This is particularly true if a reduction in the ability of generators to influence dispatch levels through rebidding ramp rates is replaced by an increase in the extent to which generators rebid price and volume to achieve the same outcome.

The AER's assertion that generator rebidding under constraint conditions can lead to productive efficiency losses is based on the assumption that a generator's bids are representative of their economic costs. The economic cost of a generator may in fact take into account a range of factors that are not necessarily incorporated in generator bids, such as the opportunity costs that are associated with undertaking plant maintenance.

Productive efficiency losses caused by generators rebidding ramp rates or making changes to dispatch inflexibility profiles is described further in Box 5.3.

Question 3

(a) Is it valid to conclude that changes in the merit order of dispatch results in productive efficiency losses?

(b) Is there a difference in productive inefficiencies caused by the rebidding of ramp rates and other forms of bidding behaviour?

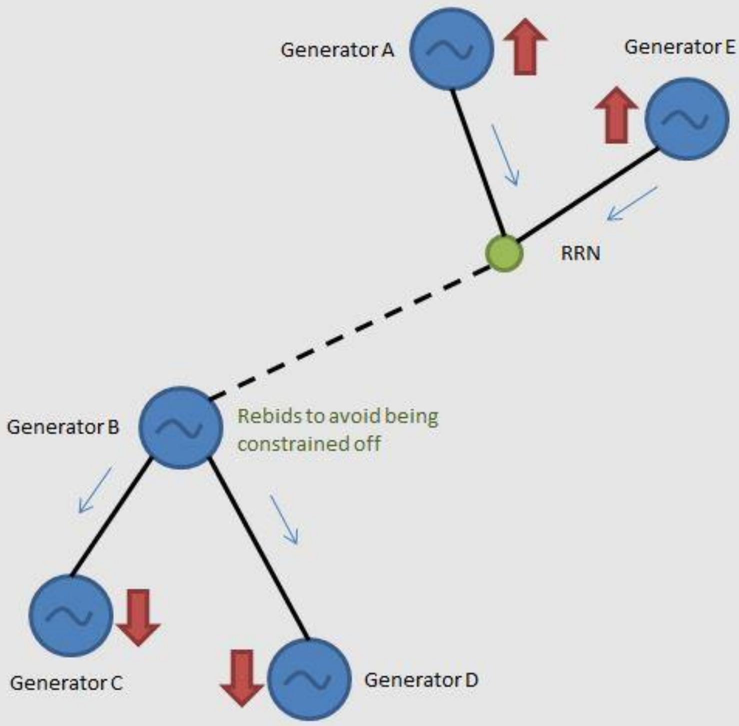
(c) Assuming productive efficiency losses can be caused by other forms of rebidding, would the AER's proposed rule reduce the extent of productive efficiency losses?

Box 5.3 Productive efficiency losses, spot price volatility and predictability

Productive efficiency losses

Figure 5.2 illustrates how productive inefficiencies may occur in circumstances where rebidding of ramp rates is undertaken under constraint conditions. As a result of congestion in the network line between generator B and the RRN, supply from generator B to the RRN is reduced and the dispatch levels from generator A are increased to compensate. As a consequence, generator B rebids to reduce the rate at which its dispatch levels can be ramped down. This forces generators C and D to be ramped down instead in order that supply does not exceed localised demand and system stability is maintained.

Figure 5.2 Productive efficiency losses and increases in price volatility from rebidding at times of network constraints



Generators C and D may have lower operational costs than generator B but, due to the rebidding of ramp rates by generator B, have their dispatch levels reduced. This results in a productive inefficiency as generator B is dispatched in place of lower cost generation.

This is exacerbated by the fact that generators situated further from the network congestion have a lower co-efficient in the constraint equation and their output must be changed to a greater extent to manage the network congestion. In other words, remote generators and interconnectors are constrained to a greater extent than generators closest to the congestion in order to achieve the same outcome. Generators C and D may therefore need to have their output constrained to a greater extent than generator B would, had it not rebid its ramp rates.

Generators C and D may also rebid their ramp rates to avoid being constrained off. In this case, generators further from the network constraint may be constrained off.

Wholesale spot price volatility and predictability

Figure 5.2 can also be used to illustrate how generator rebidding under constraint conditions can increase wholesale price volatility. As a result of congestion on the network line between generator B and the RRN, supply from generator B to the RRN is reduced and the dispatch levels from generator A are increased to compensate. Generator A is constrained on and rebids capacity to the MPC, setting the regional energy price. In response, generator E is also dispatched to meet the localised shortfall in supply caused by the congestion. Generator E is a peaking plant with relatively high operational costs. In order to maximise its exposure to the regional energy price, generator B rebids the rate that it can be ramped down to decrease the extent to which its dispatch levels will be reduced. A subsequent alleviation of the network constraint on the line between generator B and the RRN increases the capacity of the line. With the removal of the constraint, generator B sets the regional energy price at negative levels.

Generator E, having been brought online in response to high spot prices in one five-minute period, can be subsequently exposed to negative prices in the next period.

5.2.2 Price volatility and predictability

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. 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. The higher risk profile may then flow through to consumers in the form of higher energy charges.

Under conditions of network congestion, the regional price can increase rapidly as higher price generation is dispatched to prevent the network constraint being violated. Rebidding by generators can mean that the network constraint violation cannot be resolved. For example, a generator that rebids to reduce its ramp rate may mean that NEMDE is unable to reduce the dispatch from that generator to alleviate the network constraint.

In circumstances where generators have rebid capacity into negative price bands, the regional price can drop to negative levels when the network constraint ceases to bind. 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. As such, the AER asserts that the higher price volatility is primarily caused by the rebidding of price and volume but that the rebidding of ramp rates prolongs the effect by allowing the generator to reduce the rate at which it is constrained off.

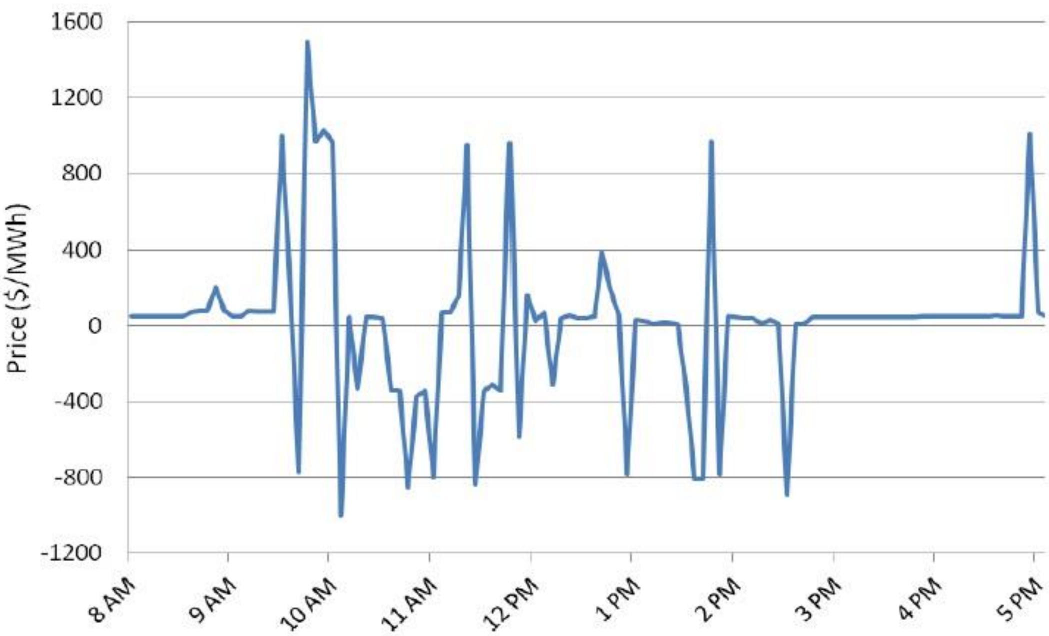
The dynamic nature of network conditions means that the capacity of the network can vary significantly between five-minute periods. Generators' response to these changes through the rebidding of price and volume or rebidding ramp rates is a second order effect that exacerbates price volatility and can be difficult to predict, thereby distorting efficient price signals for investment.

It is important to note that this issue is driven primarily by generators rebidding price and volume. That is, swings in the wholesale price from positive to negative would not be possible unless generators bid volume into negative price bands. However, the rebidding of ramp rates may prolong the effect by reducing the rate at which the dispatch levels of generators can be changed to alleviate the congestion.

The means by which generator rebidding at times of network constraints can lead to higher wholesale spot price volatility is described further in Box 5.3 above.

Figure 5.3 is taken from the AER's rule change request and provides an indication of the price volatility that occurs from generators rebidding at times of constraint conditions. This example shows five-minute price volatility in Queensland on 25 August 2012.

Figure 5.3 Five minute Queensland spot prices on 25 August 2012

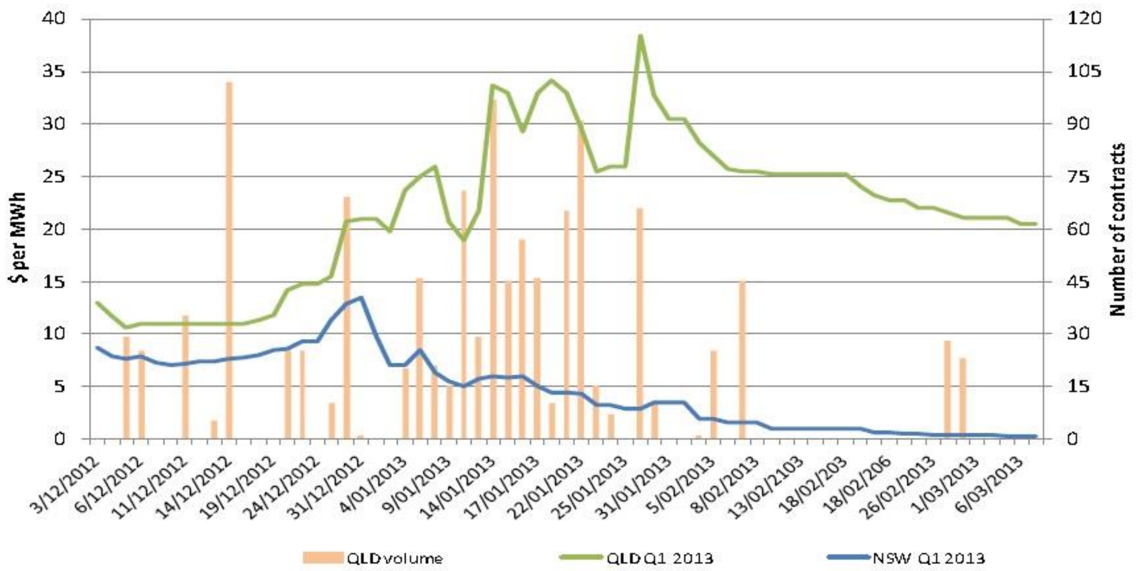


Source: Australian Energy Regulator, *Special Report – The impact of congestion on bidding and inter-regional trade in the NEM*, December 2012, p. 16.

Instances of network congestion can be difficult for market participants to forecast, particularly over the long-term. The AER considers that the ability for generators to rebid volume into negative price bands and limit ramp rates during periods of network congestion, and the spot price volatility associated with this activity, increases the risk premium that participants charge to provide a hedge against this uncertainty. These higher costs of risk management may flow through to consumers in the form of higher energy charges.

Figure 5.4 was provided by the AER as evidence of the impact on the risk premium of hedge contracts. The AER suggests that the higher price for Queensland Q1 cap contracts over the period December 2012 to March 2013 was due to the prevalence of rebidding activity at times of network constraints in Queensland during this period and the uncertainty this created for the forecast spot price. Figure 5.4 provides an indication of what the costs would have been to a customer that wished to hedge their exposure to the spot market during the period of high price volatility in Q1.

Figure 5.4 Prices for Q1 2013 $300 cap contracts on the ASX



Source: Australian Energy Regulator, *Submission to the Productivity Commission's Electricity Network Regulatory Frameworks Review*, March 2013, p. 2. Data from ASX/d-cyphaTrade.

Question 4

(a) To what extent have participants experienced a quantifiable increase in the costs of managing wholesale market risks through higher risk premiums on hedge contracts and, if so, to what extent can this be attributed to the issues discussed above?

(b) Assuming the adoption of a prudent risk management and purchasing strategy, do these higher risk premiums represent a real and measurable cost to consumers?

5.2.3 Use of peaking plant and demand side participation as a physical hedge

The AER also considers that the reduction in price predictability due to generator rebidding under constraint conditions can reduce the effectiveness of the use of peaking plant and demand-side participation as a physical hedge against high wholesale spot market prices.

As discussed in section 5.2.2, the AER asserts that the higher price volatility is primarily caused by the rebidding of price and volume but that the rebidding of ramp rates prolongs the effect by allowing the generator to reduce the rate at which it is constrained off.

The resulting uncertainty has the effect of distorting efficient price signals for investment, including decisions to invest in peaking plant or engage in demand-side participation as a hedge against high wholesale spot market prices. Many peaking generators have controlled start and stop times and may have insufficient time to react to ensure they are dispatched or, if they are dispatched, may end up generating during negative price periods.

Question 5

(a) To what extent has the rebidding of ramp rates under constraint conditions led to inefficient price signals? Is there evidence to suggest this has led to investor uncertainty?

(b) Have participants with peaking generators experienced higher levels of price unpredictability arising from the issues discussed above? Can these impacts be quantified?

5.2.4 Effectiveness of inter-regional price hedging

The AER considers that the ability to rebid ramp rates and make changes to dispatch inflexibility profiles under constraint conditions reduces the effectiveness of interconnectors, making it more difficult for market participants to hedge across NEM region boundaries. It asserts that this may lead to lower levels of wholesale market competition which could lead to longer-term impacts on efficiency and prices.

Market participants may manage spot market risks by entering into hedge contract arrangements with participants in other regions of the NEM. Hedge contracts are struck with reference to the spot price in a specific region. The counterparty to the contract in the other region is then exposed to the inter-regional spot price difference. Participants that enter into inter-regional hedge contracts may use SRA units to provide a hedge against the risk of inter-regional price separation.

SRA units provide a return to the holder based on settlement residues that accrue on the interconnector. Settlement residues accrue on interconnectors as a result of the difference between the price charged to consumers for imports in the high-priced region and the price paid to generators for exports in the adjacent low-priced region. The volume of settlement residues, and consequently the returns to SRA unit holders, is determined by the quantity of flow on the interconnector and the degree of inter-regional price separation.

Returns to holders of SRA units are reduced to zero at times of counter-price flows on interconnectors. As such, the AER considers that counter-price flows reduce the effectiveness of SRA units as a credible instrument that market participants may use to manage inter-regional price risks.

The AER asserts that a reduction in the effectiveness of SRA units as a firm hedge reduces the ability of market participants to manage risk across interconnectors resulting in less competition between regions with potential long-term flow-on effects to the price of electricity.

It is also important to note that the rebidding of price and volume by generators under constraint conditions may also lead to counter-price flows and reduce the effectiveness of SRA units in the management of inter-regional price risk.

As discussed in section 5.1.2, AEMO will override generator bids of price and volume to limit counter-price flows but will ensure that generator ramp rates and dispatch inflexibility profiles take precedence. However, even if AEMO overrides generator bids of price and volume to limit counter-price flows, “clamping” the interconnector will only reduce counter-price flows down to zero. Therefore, limiting counter-price flows through “clamping” would not change returns to holders of SRA units.

The reduction in the effectiveness of inter-regional price hedging can therefore be attributed to both the rebidding of ramp rates or dispatch inflexibility profiles and the rebidding of price and volume.

Question 6

(a) **To what extent can a reduction in the effectiveness of SRA units be attributed to the rebidding of ramp rates under constraint conditions compared to other forms of generator rebidding?**

(b) **As a NEM participant, do you consider SRA units to be an effective instrument for the management of inter-regional price risk and have you used SRA units for these purposes in the past? To what extent has this changed due to the issues discussed above?**

5.2.5 Impacts on network charges

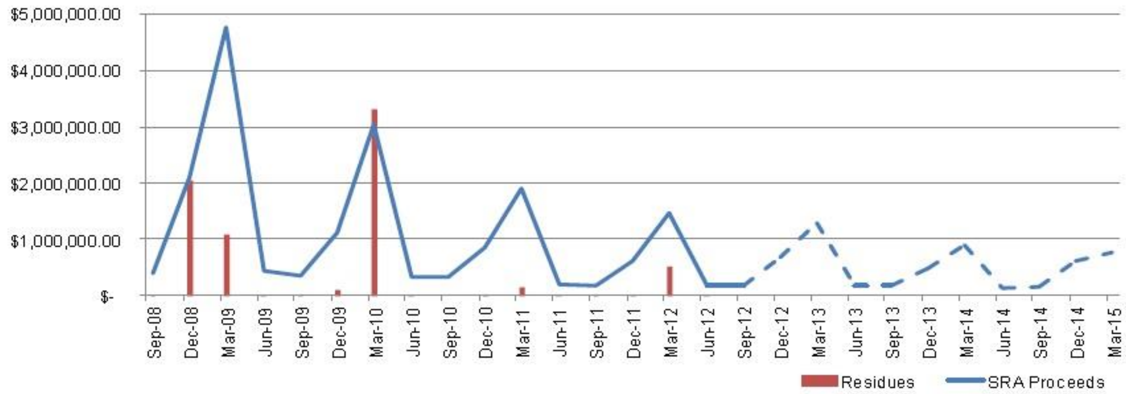
The AER suggests that a reduction in the use of SRA units reduces the proceeds from auctions, which may result in higher network tariffs for consumers.

The price that bidders are willing to pay for SRA units at auction is based on an assessment of the expected price difference between the two adjoining regions over the relevant quarter and an assessment of the expected flow on the interconnector at these times.

The inherent volatility in the wholesale market and the unpredictability of weather and other factors that affect the capacity rating of transmission lines means that accurately valuing SRA units is a difficult task. Generators rebidding ramp rates under constraint conditions can add to this uncertainty, thereby not only affecting the price that participants are willing to pay, but also the extent to which participants are willing to engage in the use of SRA units for risk management purposes. As noted in section 5.2.4, the rebidding of price and volume under constraint conditions may also have this effect.

The AER believes that recent reductions in the proceeds from SRA auctions are an indication of the reduced market valuation of these instruments. The AER has provided Figure 5.5 as supporting evidence, noting the significant decline over time of SRA proceeds on the New South Wales to Queensland interconnector. While the AER notes that expectations of lower demand and lower wholesale market prices may be a contributing factor in the decline, it also notes that the value of SRA units is driven mainly by price differences during peak demand periods, which are unlikely to significantly diminish over the coming period. The AER suggests that expectations of reduced interconnector flows and counter-price flows are the primary factors reducing the market valuation of SRA units.

Figure 5.5 New South Wales to Queensland quarterly SRA auction proceeds and settlement residues[10]



Source: Australian Energy Regulator, *Special Report – The impact of congestion on bidding and inter-regional trade in the NEM*, December 2012, p. 20.

As discussed in section 5.1.2, with a higher accumulation of negative settlement residues from counter-price flows, TUOS fees charged to customers will be higher. The proceeds from SRA auctions go to transmission network service providers and are used to offset the TUOS fees that are charged to customers. Therefore, a reduction in the proceeds from SRA auctions may result in even higher network tariffs to consumers. The net effect on consumers' bills will depend on the circumstances.

Question 7

Would the application of the AER's proposed rule affect the valuation of SRA units and the impact on network charges?

10 The blue dashed line represents estimated proceeds for future quarters based on tranches already sold.

6 The proposed rule and alternatives considered by the AER

This chapter discusses a number of aspects of the AER’s rule change request which may provide further insight into the merits of the proposed rule.

This chapter also sets out a number of alternatives to the AER's proposed rule that have either been raised by the AER as part of its current rule change request or were raised as potential alternatives under its previous rule change request.

6.1 The proposed rule

The Commission’s assessment of the rule change request will consider both the nature and extent of the costs identified by the AER (and discussed in Chapter 5) and the practicality and merits of the AER’s proposed rule. This includes a consideration of how ramp rates would be determined and enforced and a consideration of the benefits that the current rules provide to generators in the management of dispatch risk.

6.1.1 How would ramp rates be determined and enforced?

Determining ramp rates

The AER’s rule change request raises a number of questions as to how the maximum technical ramp rate would be determined.

The AER notes that ramp rates of relevant generating units may vary over time and that the determination of ramp rates is likely to be a technical exercise. The proposed rule would require generators to ensure that the ramp rates being offered reflect the maximum that the generator can safely achieve at the time. This would require generators to forecast the expected output of their generating units under anticipated conditions.

The AER would expect generators to submit ramp rates that are typical of the technical capability of their generating units under the forecast conditions. If however conditions change closer to the relevant dispatch interval then the AER proposes that generators should refine their ramp rate offers to reflect this.

While the Commission notes the AER’s intention to provide further detail in amendments to the Rebidding and Technical Parameters Guideline, the AER’s rule change request is unclear as to the definition of maximum technical ramp rates and the method generators would use to determine their maximum technical ramp rates.

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.

Under schedule 3.1 of the NER, generators are required to submit maximum ramp rates to AEMO at least six weeks prior to participating in the NEM. The NER defines this maximum ramp rate as the maximum that an item of equipment is capable of achieving under normal circumstances. The AER's rule change request is unclear as to whether this would be the default ramp rate or whether some other method of determining ramp rates should apply.

Enforcing ramp rates

The AER suggests that it would take a pragmatic approach to monitoring and enforcing compliance with the proposed rule and that it may engage independent experts to verify actual plant capabilities.

Under the current rules, each time a generator submits an offer of a ramp rate that is less than 3 MW/minute then they must provide a brief, verifiable and specific reason that relates directly to the technical reason that prevents the generator from attaining the required minimum ramp rate. Under the AER's proposed rule, the brief, verifiable and specific reason would need to be provided every time the ramp rate offered is below the maximum that the generator is capable of achieving at the time.

Generators would not be required to justify ramp rates offered in their initial bids but would be required to provide reasoning if they rebid ramp rates to a level lower than that offered in their initial bids.

If it can be assumed that the maximum technical ramp rate that a generator provides under schedule 3.1 can be achieved under normal circumstances then it would seem fair to assume that the ramp rates provided by the generator in its initial bids should remain constant at the level submitted in accordance with schedule 3.1 unless there is a technical limitation on their generating plant.

Consideration may therefore need to be given to whether generators would also be required to provide a brief, verifiable and specific reason if the ramp rates in its initial bids are lower than the maximum technical ramp rates provided in accordance with schedule 3.1.

Question 8

(a) **Is it valid to assume that generators would generally be able to operate at their maximum ramp rates submitted in accordance with schedule 3.1 of the NER?**

(b) **To what extent are the cost differences associated with different levels of ramp rates material and should this be taken into account in the determination of maximum technical ramp rates?**

(c) **Are there any issues relating to the ability of generators to determine the maximum ramp rates of their generating units?**

(d) Are there any issues relating to the enforcement of the AER's proposed rule?

6.1.2 Are the use of ramp rates legitimate as a means of managing dispatch risk?

Under constraint conditions, rebidding by generators provides a means to manage the risks of not being dispatched. While noted by the AER as the primary incentive for generators rebidding ramp rates under constraint conditions, this issue was not substantially explored in the AER's rule change request.

This issue is dealt with in other international markets by either “building-out” congestion or making use of a system of “side-payments” to compensate generators for being constrained off.[11] The NEM currently has no such mechanism to financially compensate generators for being constrained off. Instead, generators rebid to influence the outcomes that NEMDE chooses to manage network congestion.

A principal risk for generators of not being dispatched relates to an inability to meet contractual obligations and possible consequent short-term cashflow implications during periods of high spot market price and the potential loss of significant revenue.

In an energy-only market such as the NEM, a generator has an incentive to generate whenever the spot market price exceeds its short-run marginal cost (SRMC). Any additional revenue it receives from spot market prices above its SRMC contributes towards covering its fixed costs. For an unhedged generator, an individual instance of a reduction in dispatch levels at a given price simply means less overall revenue and is unlikely to be of significant detriment. A repeated reduction in dispatch levels may prove problematic for such a generator over the longer-term if it does not receive sufficient revenue to cover its fixed costs.

However, generators in the NEM do not typically rely on the spot market alone for their revenue but also enter into contractual arrangements with other NEM participants to set a fixed price for a proportion of their generation output. A generator’s intended level of output often reflects the level of its hedge contract position. Generators that cannot generate sufficient output to cover their contractual position risk losing significant revenue. The inability of a generator to meet contractual obligations, even for short periods of high spot market price, can create significant cash flow issues.

Hedge contracts are also used by generators to underpin investments that are often a necessary requirement for access to third-party financing. A generator that cannot adequately manage the risk of not being dispatched has a reduced incentive to enter into hedge contracts with other market participants. Without revenue certainty, they may find it difficult or expensive to obtain financial backing, thereby increasing the costs of capital and reducing the efficiency of investments.

11 The Optional Firm Access model recommended in the AEMC's Transmission Frameworks Review would provide this financial compensation.

A reduced incentive for generators to enter into hedge contracts with other participants may reduce the availability and liquidity of hedge contracts and thereby increase the exposure of retailers and other new entrants to spot price risk. This may lead to upward pressure on retail prices as retailers require greater compensation for the increased risks of market participation.

> **Question 9**
>
> **Would a requirement to submit ramp rates that reflect the technical capability of generating plant increase risks to generators? What form would these risks take and can they be quantified?**

6.1.3 Why was the AER's proposed approach not adopted previously?

Under the AER's previous rule change request discussed in section 2.3, the AER proposed the possibility of requiring generators to submit ramp rates that reflect the technical capabilities of generating plant. However, the AER decided against pursuing this approach and proposed the application of minimum ramp rates instead. The AER reasoned that:

- NEMMCO advised the AER that a ramp rate of 3 MW/minute was sufficient to allow NEMMCO to manage system security incidents.
- Operating plant at its ramp rate limits typically increases wear and tear and results in higher maintenance costs. These costs may be difficult to quantify and not be able to be readily reflected in generators' price and volume offers.
- A requirement to operate plant at its technical limits may unfairly penalise more flexible plant and favour/incentivise investment in slower technology or the reduction in performance of existing plant.
- Practical implementation is likely to be lengthy and complex from the perspective of NEMMCO and generators.

The AER considers that, amongst other issues, generation ownership changes and the abolition of the Snowy region, have resulted in increasing prevalence over the last three years of generators rebidding ramp rates to achieve commercial objectives leading to inefficient market outcomes. The AER considers that this requires a more flexible approach to the requirements on generator ramp rates.

In the current rule change request, the AER considers that generators should be able to negate the effects of wear and tear by rebidding volumes within price bands to limit the amount and frequency by which their output changes.

The AER also considers that generators are unlikely to have an incentive to actively reduce the technical ramp rate capabilities of their plant because, for the majority of time, generators have an incentive to maintain flexible plant so they can respond quickly to high or low prices.

The AER considers that requiring generators to limit their ramp rate bids and rebids and dispatch inflexibility profiles to levels that correspond to the actual physical or technical capability of their plant, is just a refinement to meet the original intent of the AEMC's previous rule change request and would make the treatment of these parameters in the rules consistent with the inflexibility requirements of 3.8.19(a) and frequency control ancillary service offers in 3.8.7A.

Question 10

(a) Would the proposed rule create an incentive for generators to actively reduce the technical ramp rate capability of their generating plant?

(b) Since the making of the AER's previous rule change request, have conditions in the NEM changed such that a minimum ramp rate of 3 MW/minute is no longer sufficient?

(c) Would generators be able to negate the effects of wear and tear by bidding volumes within price bands as suggested by the AER?

6.2 Alternative approaches considered by the AER

In its rule change request the AER discusses a number of other approaches that could act as potential alternatives to the proposed rule. These approaches are discussed further below and include:

- an application of minimum allowable ramp rates to individual physical generating units rather than aggregated units;
- generators required to bid their maximum technical ramp rates at times of network constraints; and
- generators required to submit ramp rates that are at least a certain percentage of their capacity.

6.2.1 Application of minimum ramp rates to individual physical generating units

This approach would require generators to submit minimum ramp rates for each of their individual physical generating units rather than for aggregated units. A number of generators in the NEM own and operate generating units that are aggregated from a number of smaller individual physical units. Minimum ramp rates applied to each of these individual physical units rather than a single minimum ramp rate for the aggregated total would increase the overall minimum ramp rate that would apply. For example, a 600 MW generating unit that is comprised of three 200 MW individual physical units would be required to submit a minimum ramp rate of 9 MW/minute (3 MW/minute x 3 generating units) rather than 3 MW/minute as currently applies.

This approach was considered under the AER's previous rule change request on generator ramp rates. The Commission at the time determined against applying minimum ramp rates to individual physical units based on confirmation from NEMMCO that ramping capability for existing aggregated units was likely to be sufficient for them to manage power system security. It was also noted that linking ramp rates to individual physical units might place a disproportionate burden on aggregated generators where a number of smaller physical units have been aggregated.

In making the rule, the Commission recognised that applying minimum ramp rates to aggregated units, rather than individual physical units, might create an incentive for generators to aggregate units to effectively reduce their minimum ramp rate requirements. An increase in the registration of aggregated units would shift the burden for ramp rates to non-aggregated units.

However, the Commission noted that the NER requires that generators who wish to aggregate their units for the purposes of central dispatch and settlements must apply to NEMMCO to do so. Under the NER, some of the conditions that must be fulfilled for NEMMCO to approve application for aggregation are that power system security must not be materially affected by the proposed aggregation or that such aggregation would not materially distort central dispatch.

The Commission was therefore satisfied that the NER provides 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. The Commission therefore considered that the aggregation provisions in the NER could be used to manage the concerns around incentives to aggregate.

Question 11

(a) **What are the costs and benefits of requiring generators to submit minimum ramp rates for each of their individual physical units rather than a single minimum ramp rate for the aggregated total?**

(b) **Does the view still hold that the aggregation provisions can be used to manage concerns around incentives to aggregate?**

6.2.2 Maximum technical ramp rates at times of network constraints

Another approach would be for generators to bid their maximum technical ramp rates only at times when network constraints are binding. This would provide AEMO with greater flexibility to manage network congestion and alleviate constraints and would also assist the management of system security as the optimal economic dispatch determined through NEMDE would more likely be able to select the most effective method of addressing congestion in the network.

The AER notes that evidence of rapid rebidding that occurs in response to congestion suggests that generators are aware when network constraints are binding and would therefore be able to appropriately respond by rebidding ramp rates to their technical maximum. The AER defines all generators affected by network constraints as those sitting on the left hand side (LHS) of the relevant constraint equation. All generators with a coefficient less than 0.07 would not be affected.

The AER notes that a shortfall of this approach is that it may create a circular effect if, in response to alleviation of the binding constraint, generators rebid ramp rates back to previous levels and subsequently the same constraint were to bind again within a short timeframe. There is therefore a question as to how long generators would have to maintain ramp rates at their technical level.

A further potential concern is the level of "wear and tear" on generating plant that may occur if generators are required to bid ramp rates at their technical maximum. In order to avoid these issues, it may be more appropriate to require generators to bid ramp rates to a level that is below the maximum technically capable but higher than the current minimum of 3 MW/minute. For example, ramp rates could be based on the average ramp rate that a generator bid over a defined period of time leading up to the occurrence of the network constraint.

Question 12

(a) What are the costs and benefits of requiring generators to submit maximum technical ramp rates only at times of network constraints?

(b) Are there any variations to this approach, such as the use of average ramp rates, which may be more preferable?

6.2.3 Ramp rates as a percentage of plant capacity

A further alternative would be for generators to specify a ramp rate that is at least equivalent to a certain percentage of the capacity of their generating plant. Depending on the size of the percentage applied, this approach may allow AEMO to more effectively manage network congestion and system security than the current minimum ramp rate of 3 MW/minute.

However, if the nominated percentage of capacity is too large, the minimum ramp rate may be beyond the technical capability of some of the larger thermal generating units. A number of generating units may therefore be required to operate at their technical limitation based ramp rate.

Question 13

(a) What are the costs and benefits of requiring generators to submit a ramp rate that reflects a percentage of the capacity of their generating plant?

(b) Assuming adoption of this approach, what percentage of capacity should be required?

6.2.4 Other approaches

There may be a range of other approaches that could be applied in addition to those considered by the AER.

The AER has framed the determination of ramp rates in its proposed rule as a purely technical exercise. However, given the trade-off between ramp rate capability and the costs incurred, the Commission is particularly interested in any options which provide incentives to utilise or develop ramp rate capability. Such an approach should encourage higher ramp rates to be provided by those generators with lower technical costs and more flexible plant at times when this is valued by the market.

However, the Commission is also conscious that altered incentives, or any new technical or regulatory requirements on ramp rates, may lead generators to pursue similar commercial outcomes through alternative means. For example, consideration would need to be given to whether a reduction in the ability of generators to influence dispatch levels through rebidding ramp rates may be replaced by an increase in the extent to which generators rebid capacity into negative price bands to achieve the same outcome. As mentioned previously, many of the costs associated with generators rebidding ramp rates under constraint conditions can be associated with other forms of rebidding.

As noted, the rule change request recently received from the South Australian Government relating to the good faith bidding provisions in the NER will represent an opportunity to assess potential inefficient costs associated with all forms of generator bidding and rebidding. This may include costs where the rebidding of ramp rates may be a contributing or supporting factor but which is not necessarily the principal or underlying cause.

Question 14

Are there any other alternative approaches? To what extent could an alternative approach be based on incentives rather than relying on regulatory/technical requirements?

7 Lodging a submission

The Commission has published a notice under section 95 of the NEL for this rule change request inviting written submissions. Submissions are to be lodged online or by mail by 27 March 2014 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's guidelines for making written submissions on rule change requests.[12] The Commission publishes all submissions on its website subject to a claim of confidentiality.

All enquiries on this project should be addressed to Sebastien Henry on (02) 8296 7800.

7.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code "ERC0165". The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

7.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Or by Fax to (02) 8296 7899.

The envelope must be clearly marked with the project reference code: ERC0165.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

12 This guideline is available on the Commission's website.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
CVP	constraint violation penalty
FCAS	frequency control ancillary services
MPC	market price cap
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NER	National Electricity Rules
RRN	regional reference node
SRA	Settlement Residue Auction
SRMC	short-run marginal cost
TUOS	transmission use of system

A The AER’s previous rule change request

On 15 January 2009, the AEMC made a final determination on a rule change request submitted by the AER in relation to the bidding and rebidding of ramp rates, market ancillary service offers, and dispatch inflexibility.

The rule change request was precipitated by an AER investigation into the events of 31 October 2005. On that day, 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 AER also provided examples where generators had rebid market ancillary service offers or dispatch inflexibility profiles to limit the rate at which their dispatch targets could be reduced in response to binding network constraints.

A.1 The AEMC's final determination

The Commission’s final determination on the AER’s previous rule change request imposed:

- a minimum ramp rate of 3 MW/minute except where it could be demonstrated to NEMMCO that a lower ramp rate is required for technical or safety reasons. Where a generator has a nameplate capacity of less than 100 MW, the minimum ramp rate to apply is 3 per cent of maximum capacity. The ramp rate specified must be no more than the maximum ramp rate that an item of equipment is capable of achieving in normal circumstances;

- a requirement for market ancillary service parameters bid by generators to reflect the technical capability of the generator’s plant; and

- a requirement that generators declare themselves “inflexible” only when plant technical constraints justify such a declaration.

Prior to the Commission’s final determination, the only restriction in the NER on the ability of scheduled generators to rebid either ramp rates and market ancillary services or declare themselves inflexible was that offers or rebids must be made in good faith. Clause 3.8.22A of the NER provides that generators must have an intention to honour their bids and offers unless the material conditions and circumstances upon which the original offer was based change.

The clauses relating to these requirements have remained unchanged since the AEMC’s final determination in January 2009 and are all reflected in the current version of the NER.

A.1.1 Ramp rates

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.

The AER's proposed minimum ramp rate of 3 MW/minute was based on an analysis of generator bids prior to the time of the rule change request which showed that all except for a handful of generators bid at 3 MW/minute or greater most of the time. The AER considered that, based on past ramp rate bidding practices, a level of 3 MW/minute minimum ramp rate would be sufficient for most generators. The AER also 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.

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 determined that the requirement for generators to meet a minimum ramp rate of 3 MW/minute be a civil penalty provision. 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.

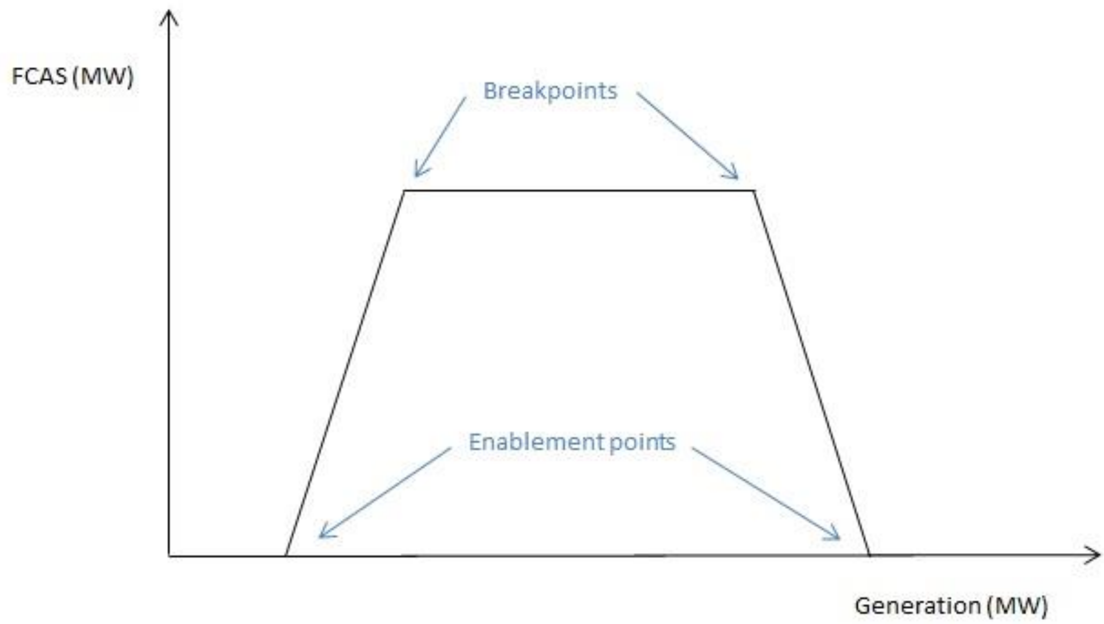
The Commission considered that the objective of the AER's rule change request was to provide NEMMCO with sufficient ramp rate capability for it to be able to manage power system security. The decision at the time to use 3 MW/minute as the minimum value was based on advice from NEMMCO that this would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

A.1.2 Market ancillary service offers

The AEMC's final determination changed clause 3.8.7A of the NER to require generators to offer frequency control ancillary services (FCAS) that reflect the technical capability of the generator's plant.

Offers from generators for the supply of FCAS include specifications of capability in the form of a trapezium. The FCAS trapezium defines the enablement points and response breakpoints for a particular generating unit. As shown in Figure A.1, the FCAS trapezium represents the level of FCAS that can be provided by a generating unit as a function of generation output.

Figure A.1 Market ancillary service offers



Prior to the AEMC final determination in January 2009, there were no restrictions in the NER on the levels of the parameters that construct the FCAS trapezium. In support of the rule change request, the AER cited examples of generators rebidding the enablement points of their FCAS offers to "trap" generation output levels at close to maximum output in response to network congestion that would otherwise have the effect of reducing dispatch levels.[13]

The AER's proposal that offers for the provision of market ancillary services should reflect the technical capability of the generator's plant was principally driven by the need for AEMO to manage system security in an economically optimal fashion through the operation of NEMDE without resorting to directing generators to change output.

During consultation on the rule change request, stakeholders raised concern that it may not be possible to completely align the market ancillary service bids to actual capability because precise capabilities vary with time and operating conditions. They also noted that an obligation to demonstrate that market ancillary service bids represent the physical or technical capability of plant is likely to be a potentially cumbersome and costly exercise.

Stakeholders contended that fixed limits on market ancillary service enablement points would avoid the need to define the technical capability of the plant and would align the requirements with those for ramp rates where a minimum ramp rate of 3 MW/minute was chosen to avoid the costs and difficulties of a solution based on technical limits.

In response to stakeholder concerns, the Commission considered that the complexity that could result from the need to accommodate different conditions, and the fact that the AER would adopt a pragmatic approach to compliance, was sufficient to clarify that market ancillary service parameters should reflect plant's technical capability.

A.1.3 Dispatch inflexibility

The AEMC's final determination changed clause 3.8.19(a) of the NER to require generators to declare inflexibility only when plant conditions justify such a declaration.

Prior to the AEMC final determination in January 2009, there were no restrictions in the NER on generators declaring inflexibilities with regard to the operation of their generating plant. Under constraint conditions, a generator could declare themselves unable to move from their existing dispatch levels regardless of whether they actually faced a physical operating restriction. NEMMCO's ability to efficiently manage system security was potentially hindered by unjustified declarations of inflexibility.

The Commission considered that requiring relevant scheduled generators and market participants to declare inflexibility only when plant technical constraints justify such a declaration would improve the market's ability to deliver competitive outcomes and provide NEMMCO with the flexibility to manage events for the safe and secure operation of the power system.

13 Generators could "trap" dispatch levels at close to maximum output by rebidding enablement points so that the upper limit was close to the maximum output and the lower limit was only a relatively small amount of energy below the upper limit.

A.2 Assessment against the NEO

The Commission's determination was based on the following assessment against the NEO:

1. **Requiring relevant scheduled generators and market participants to provide a ramp rate between the stipulated minimum and the maximum** would assist NEMMCO to maintain system security during critical periods when network constraints are binding. This would facilitate the smooth and efficient operation of the spot market, which is one of NEMMCO's core functions. In addition, the amendment would contribute more broadly to the achievement of the NEO by clarifying the obligations, which in turn would enhance enforceability of the relevant provisions of the NER. This would ultimately work to the benefit of all market participants and stakeholders.

2. **Requiring relevant scheduled generators and market participants to provide market ancillary service parameters for generators that reflect the technical capability of the generator's plant** would assist NEMMCO to operate the NEM so that electricity supply is secure. In particular, by preventing scheduled generators from varying their market ancillary service offers to pursue commercial objectives, NEMMCO would be able to respond more effectively to contingency events and during periods when network constraints are binding. This would help to facilitate the smooth and efficient operation of the spot market, one of NEMMCO's core functions.

3. **Requiring relevant scheduled generators and market participants to declare inflexibility only when plant technical constraints justify such a declaration** would improve the markets' ability to deliver competitive outcomes and provide NEMMCO with the flexibility to manage events for the safe and secure operation of the power system. The amendment would contribute more broadly to the achievement of the NEO by enhancing the efficient operation of the market.

The Commission considered that the proposed rule was unlikely to impose significant costs on the relevant generators and market participants as historical evidence indicated that most participants operated their plant within the technical parameters specified in the proposed rule. The rule change was also not likely to require major changes to the relevant scheduled generators', market participants' or NEMMCO's systems and processes since the rule change clarified provisions that were already in place.

The Commission considered that the rule would assist NEMMCO in responding to system security issues effectively and hence improve the reliability and security of the power system, and improve the efficiency of the NEM. The Commission also considered that the rule would enhance the AER's ability to enforce the provisions, which in turn would help to maintain system security as well as efficient dispatch outcomes in the NEM.