AEMC

REVIEW

Australian Energy Market Commission

FINAL REPORT

INVESTIGATION INTO INTERVENTION MECHANISMS IN THE NEM

15 AUGUST 2019

INQUIRIES

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ABOUT THE AEMC

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

EXECUTIVE SUMMARY

1 The change in generation technology has altered the operational dynamics of the power system and our need for system services to be able to keep it secure. Many of the system services needed for power system security were provided as a matter of course by synchronous generation when producing energy. However, with the changing energy mix, there is a trend towards many of these generators operating for fewer hours of the day, with a number of generators recently retiring from the market altogether. Both factors have resulted in substantially reduced levels of system strength in some parts of the power system.

2 Minimum levels of system strength are required to be maintained at all times in order to maintain a secure power system. System strength refers to the relative change in voltage for a change in load or generation at a connection point. Low levels of system strength can jeopardise the ability of generators to operate correctly, thus threatening system security.

3 The Australian Energy Market Operator (AEMO) has a number of "safety net" tools available to it if the power system becomes insecure, or becomes unreliable. One of these tools is to intervene in the market by directing a generator which can provide required security services to come on line. However, once AEMO has intervened in the market, directed generators must be compensated, along with participants who are dispatched differently due to the intervention. Intervening in the market may also have implications for the wholesale price due to the use of "intervention pricing" – a practice designed to minimise market distortion by preserving price signals at the level they would have been but for the intervention.

4 Under the National Electricity Rules (NER), there is a framework to maintain sufficient system strength in the power grid. The Commission created this in 2017 to deliver efficient and timely action to ensure system strength is maintained as the generation mix changes. Importantly the system strength framework was intended to address this issue proactively and remove the need for frequent intervention by AEMO. While the "safety net" that the intervention framework provides is important, it was not intended to be used to provide ongoing maintenance of power system security. In the case of South Australia, the frequent use of directions by AEMO would not be necessary if contracts with synchronous generators for the provision of system strength services, or other measures such as synchronous condensers, were in place as envisioned by the framework in the NER for managing system strength.

5 The increasing use of interventions in South Australia has drawn attention to a number of issues regarding the interventions framework set out in the NER, including the impact of directions and intervention pricing on spot prices and investment signals, and the impact on consumers of both intervention pricing and compensation payments to directed and affected participants.

6 Investigation into intervention mechanisms and system strength

7 In response to concerns about increasingly frequent reliance on interventions, and in

accordance with a recommendation made in the Reliability Frameworks Review final report[1], the Australian Energy Market Commission (AEMC or Commission) commenced this investigation into the regulatory frameworks that govern the use of interventions in the NEM. The AEMC has split its consideration of this investigation into two parts.

8 *Part A - Interventions and compensation*

9 The AEMC's investigation explores issues associated with the current interventions and compensation frameworks in the NER and identifies potential changes that could improve the efficiency and effectiveness of the frameworks.

10 Part A is the focus of this report which sets out the Commission's recommendations on the design and application of the interventions framework, and includes a number of suggested rule change requests to implement the proposed changes. The Commission will not be consulting further on these recommendations at this stage. Instead, the Commission considers it more efficient to undertake targeted consultation when relevant rule change requests are submitted. In accordance with normal procedures, the Commission will undertake further consultation in relation to the two draft determinations published in conjunction with this report.

11 The AEMC also received four separate rule change requests from AEMO relating to a number of issues with the design of the current interventions frameworks. Two of these rule change requests raise important issues and as such consultation on them commenced as part of this investigation. The AEMC has published draft determinations with respect to these rule change requests, which are available on the AEMC website.[2]

12 The other two rule change requests have been dealt with independently of this investigation as they involved issues that are machinery in nature and uncontroversial.

13 *Part B - System strength and other services*

14 The Commission is also considering whether improvements can be made to the minimum system strength and inertia frameworks in the NER to more effectively and efficiently identify and address shortfalls in system strength and inertia as they arise in NEM regions. The application of these frameworks should obviate the need for AEMO to maintain system security by intervening in the operation of the market.

15 The minimum system strength and inertia frameworks in the NER are not the focus of this report. The Commission will progress this work separately and intends to publish recommendations on any proposed changes to the minimum system strength and inertia frameworks in October 2019. Recommendations may include possible changes to policy frameworks and potential future rule change requests, as well as any further actions where required.

16 *Interventions and compensation areas of focus*

1 AEMC, Reliability Frameworks Review - Final Report, July 2018

2 Links to draft determinations available at: https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader and https://www.aemc.gov.au/rule-changes/threshold-participant-compensation-following-market-intervention

17 The AEMC's investigation explores issues associated with the current interventions and compensation frameworks in the NER and identifies changes that could improve the efficiency and effectiveness of the frameworks. The investigation considers the application of the interventions framework to the maintenance of system security as well as reliability, and the hierarchy, or sequence of use, of the three different intervention mechanisms (reliability and emergency reserve trader (RERT), directions and instructions).

18 There are three key aspects of the interventions framework which the Commission has examined.

1. Intervention pricing and the regional reference node (RRN) test - The rationale for intervention pricing, the experience to date with its application, and whether the use of intervention pricing in connection with system strength directions is causing market distortion and sending inefficient signals to investors.
2. Compensation to directed and affected participants - The compensation framework that is triggered when AEMO intervenes in the market by issuing a direction or activating the RERT, and whether this framework has the potential to create incentives for inefficient participant behaviour and impose higher than necessary costs on consumers.
3. Hierarchy of intervention mechanisms - The requirement that the RERT be activated in preference to directions and instructions, and whether this may result in inefficient cost impacts on consumers in some circumstances.

19 Intervention pricing

20 One of the principal issues considered by the Commission through this investigation is the use of intervention pricing in connection with AEMO intervention events.

21 Intervention pricing is a practice intended to minimise market distortion when AEMO intervenes in the market. It does this by preserving price signals at the level which, in AEMO's reasonable opinion, they would have been at had the intervention event not occurred.

22 Under the current rules, AEMO applies intervention pricing whenever it activates the RERT. By contrast, when AEMO issues a direction, it has to apply the RRN test to determine whether to apply intervention pricing. The test essentially asks whether directing a plant at the RRN would have avoided the need for the direction actually issued. Broadly, the objective of the test is to determine whether there is a region-wide scarcity of the service that is the subject of the direction, or whether the problem being fixed is localised and remote from the RRN. If the problem is region-wide (or localised but in a part of the region that contains the RRN), then it will be important to preserve price signals and the incentive they create for investment. This is the aim of intervention pricing.

23 However, the Commission considers that the test for when intervention pricing should apply must also have regard for the nature of the service that is being obtained by the intervention. For example, the recent directions in South Australia have been issued by AEMO for the purposes of obtaining system strength. However, the application of intervention pricing in these instances has the effect of maintaining a scarcity signal for energy. This may encourage new entrants to invest in additional capacity, regardless of whether those investments

support or undermine system strength.

24 One of the rule change requests submitted by AEMO proposes to change the wording of the RRN test and to extend its reach so that it encompasses the RERT as well as directions. This would have the effect of limiting the use of intervention pricing in connection with the RERT, consistent with the current use of the test in respect of directions. The request also proposes to change the wording of the RRN test to improve clarity.

25 In order to reduce market distortion and costs to consumers associated with intervention pricing, the Commission has made a draft determination to extend the reach of the RRN test to encompass the RERT. Importantly, the determination removes the application of intervention pricing where an intervention is intended to address a shortfall of a service that is not traded in the market (system strength, inertia, etc). The draft determination also amends the test to make clear the circumstances in which a localised deficiency of a market traded commodity will and will not trigger intervention pricing. Thus, intervention pricing will apply where a localised deficiency occurs in a part of the region that contains the RRN but will not apply if the localised deficiency occurs in a part of the region which, due to a network or other constraint, does not include the RRN.

26 **Draft determination:** The Commission has published a draft determination which extends the reach of the test to encompass the RERT as well as directions, removes the application of intervention pricing in instances where an intervention has been issued for the purpose of addressing a shortfall in a service that is not traded in the market, and clarifies the operation of the test in circumstances where there is a localised deficiency of a market traded commodity.

27 **Compensation**

28 While intervention pricing is (subject to the RRN test) used to set prices in the NEM during an intervention event, there is also a compensation framework to ensure that participants who have been directed by AEMO to provide services are not out-of-pocket. This framework also compensates participants affected by the intervention in order to put them in the position that they would have been in had the intervention not occurred. The cost of compensating directed and affected participants is passed through to market customers and, ultimately, consumers.

29 *Directed participant compensation*

30 Currently, generators who are directed to provide energy or FCAS are compensated based on the 90th percentile of spot prices over the preceding 12 months. The consultation paper explored whether the current compensation framework for directed participants is creating inefficient incentives for generators to withdraw from the market if they think they can earn more under direction. During system strength directions in South Australia, spot prices are typically much lower than the 90th percentile price because these interventions tend to occur during periods of high wind output and low demand.

31 The Commission considers that there would be merit in adopting a cost based approach to calculating compensation for directed participants. This would avoid the payment of windfall gains to lower cost generators and would ensure that higher cost generators are adequately

compensated. A cost based approach will also provide greater predictability and certainty that directed participant costs will continue to be compensated adequately as market conditions and the 90th percentile price change over time.

32 **Recommendation:** AEMO to submit a rule change request to change the basis of directed participant compensation

33 *Affected participant compensation*

34 Affected participants are those parties whose dispatch targets have been affected as a result of an AEMO intervention event.

35 Affected participants are entitled to receive from, or pay to, AEMO an amount that puts them in the position they would have been in but for the direction or RERT activation. For example, if a generator's output is reduced as a result of an intervention, it will be paid compensation by AEMO to put it in the position that it would have been in had the intervention event not occurred.

36 The extensive use of directions for system strength in South Australia raises questions regarding the payment of compensation to affected participants. This in turn raises a more fundamental question as to whether and/or when compensation should be paid to (or by) participants affected by interventions given that a foundational principle underlying the NEM is that generators have no right to be dispatched in the wholesale market.

37 A direction is a way of meeting, or satisfying, a physical constraint on the system, where that constraint is not, or cannot, be represented in NEMDE. If it were possible to implement the system strength requirements as constraints, AEMO would do so. In that case, there would be no compensation for being constrained down, because generators have no right to be dispatched in the NEM.

38 The Commission has made a recommendation to align the treatment of participants affected by system security interventions to the treatment of participants affected by constraints under the normal dispatch of the system. In reaching this conclusion, the Commission has also considered that the dispatch targets used to calculate affected participant compensation would never be realised in practice as they constitute an insecure power system. Further, these dispatch targets are able to be influenced by affected participants' bidding strategies so as to optimise the receipt of affected participant compensation. Accordingly, they are not considered a sound basis on which to determine compensation.

39 **Recommendation:** AEMO to submit a rule change request to narrow the circumstances in which affected participant compensation is payable to those instances where intervention pricing applies in connection with an intervention event in accordance with the revised regional reference node test.

40 *Compensation threshold for directed and affected participants*

41 One of the rule change requests submitted by AEMO relates to the threshold that applies to compensation claimed by directed and affected participants. At present, the NER includes a $5,000 threshold which limits the payment of compensation both to and by affected participants. The threshold also limits the payment of compensation to directed participants

in the event they claim additional compensation beyond the amount automatically calculated. AEMO's proposal seeks to change the threshold so it applies to each intervention event, rather than to each trading interval.

42 The Commission considers that it is appropriate for the NER to enable directed participants to recover the costs they incur when providing a service under direction. If this necessitates an additional compensation claim, the application of a "per trading interval" threshold should not limit the amount of compensation that can be paid such that directed participants incur loss. Accordingly, the Commission agrees with AEMO that the compensation threshold should apply per direction, not per trading interval, in such instances.

43 The Commission has determined not to change the threshold as it relates to affected participants given that the Commission is recommending that affected participant compensation only be payable in respect of interventions which trigger intervention pricing under the revised regional reference node test. Changing the threshold to apply per event rather than per trading interval runs counter to this recommendation as it would significantly increase the quantum of compensation payable to and by affected participants.

44 **Draft determination:** Accordingly, the Commission has made a draft determination to make a more preferable rule in which the change to the $5,000 threshold is made in relation to directed participants' additional compensation claims but not in relation to the compensation payable to affected participants.

45 **Counteractions**

46 In order to minimise the number of affected participants and impact on interconnector flows, AEMO may seek to offset the impact of an intervention by issuing counteraction instructions to adjust the dispatch targets of certain market participants.

47 Counteractions have not generally been used in connection with system strength directions in South Australia because there are rarely scheduled generators operating at levels above their minimum loading such that they can be constrained down to offset the impact of a direction to another scheduled generating unit to come online.

48 Nevertheless, the Commission considers that requiring AEMO to "manually" adjust dispatch targets in order to limit the number of affected participants and confine the impact of an intervention to a single region can increase costs compared with the alternative of allowing NEMDE to optimise targets automatically (at least cost) in the wake of an intervention event. The Commission's view is that cost minimisation is a more important objective than minimising the number of affected participants and impact on interconnector flows.

49 **Recommendation:** AEMO to submit a rule change request to remove the current requirement to issue counteraction instructions in order to minimise the number of affected participants and the impact on interconnector flows.

50 *Transparency and reporting*

51 The Commission considers that there would be benefits from increasing the level of transparency surrounding the frequency and quantum of compensation paid to directed and affected participants and improving the timeliness of post-event reporting.

52 The level of information currently published regarding the cost of compensation is limited and is aggregated to such a degree that there is no visibility as to the share of compensation being paid to directed and affected participants. The quantum of compensation paid to particular participants is only publicly available where an independent expert report has been prepared and that report identifies the directed or affected participant.

53 The Commission considers it appropriate that greater transparency regarding the quantum of compensation paid to individual participants is warranted since this can shed light on any bidding behaviour patterns that may be adopted to maximise the payment of compensation at the expense of consumers. This could be supported by changes to the NER to require AEMO to publish information on intervention events in a timely manner.

54 **Recommendation:** The AER to submit a rule change request to impose a clear requirement on AEMO to publish its market event reports within a clearly defined period and to require reports to include information regarding the amount of compensation payable to each directed and affected participant.

55 The Commission also considers that there would be merit in requiring an appropriate level of transparency regarding the payment of compensation to individual participants affected by the activation of the RERT. This would be beneficial as it would shed light on whether the activation of the RERT resulted in affected participant compensation being paid to generators that were turned down in response to the RERT activation. It would also shed light on compliance by AEMO with the proposed cost minimisation principle regarding the choice of intervention mechanisms. The Commission notes that there is currently a gap in the NER in relation to recovering the cost of affected participant compensation following activation of the RERT. The basis for recovery of RERT costs should be clarified through a change to the NER.

56 **Recommendation:** AEMO to submit a rule change request to provide a clear basis on which to recover affected participant compensation costs due to a RERT activation and include a requirement in the NER to report on the payment of compensation to individual affected participants following a RERT activation.

57 **Hierarchy of intervention mechanisms**

58 The NER outline a two-level hierarchy for the use of intervention mechanisms. In time of "supply scarcity", after dispatching all valid bids and offers, AEMO must use reasonable endeavours to first exercise the RERT and then, if necessary, issue either directions or instructions.

59 The Commission considers that, given the cost of the RERT relative to other mechanisms, this provision may produce inefficient cost impacts on consumers in some circumstances. The Commission acknowledges that, during a reliability event, most if not all generators will typically participate in the market voluntarily and therefore will not be available to direct. However, the Commission recognises that there can also be instances (such as February and March 2017) where units remain available to direct, which may be lower cost than activating the RERT.

60 In order to promote a cost minimisation approach, the Commission considers that it would be appropriate to replace the existing hierarchy with one which is based on a principle of

minimising direct and indirect costs to consumers.

61 **Recommendation:** AEMO to submit a rule change request to introduce a new principle to guide AEMO in prioritising the use of RERT, directions and instructions. The principle would reflect that prioritisation should minimise direct and indirect costs and maximise effectiveness of the intervention.

62 **RERT triggering the market price cap**

63 This investigation has considered the appropriateness of the application of intervention pricing following activation of the RERT. The Commission has considered the option of replacing intervention pricing with an approach whereby the spot price is set to the market price cap when the RERT is activated, similar to the approach already adopted when involuntary load shedding occurs.

64 Under the current approach, the spot price does not automatically rise to the market price cap when the RERT is activated - this will only happen if the intervention pricing run of the NEM dispatch engine (NEMDE) yields the market price cap. As a result, it is possible for prices to remain at relatively low levels (say approximately $300 per MWh), despite AEMO having intervened to activate out-of-market generation and demand response.

65 The Commission considers that there are significant reasons why it would not be appropriate to automatically apply the market price cap whenever the RERT is activated. The RERT is used to provide additional capacity to maintain reserves and, in some cases, to prevent load shedding. Thus it is not activated exclusively in scenarios where a supply shortfall would have occurred.

66 Further, setting prices at the market price cap may not be appropriate due to the nature of the RERT. Activating the RERT may require "pre-activation" of reserves (e.g. demand response contracts) to occur in advance of when the shortfall is projected to arise. Once activated, reserve contracts may stipulate minimum run times, meaning that the duration of the intervention event may be longer than is in fact required. As a result, emergency reserves may be activated for longer than required, not just to avoid load shedding, but also longer than required to maintain market reserves. This creates a risk of tripping the cumulative price threshold and triggering an administered price period, thereby muting scarcity signals and demand response incentives at a time when they are most needed.

67 The Commission recommends leaving the current arrangements in place so that RERT activation for reliability purposes triggers intervention pricing.

68 **Mandatory restrictions**

69 The final aspect of the interventions framework considered by the Commission as part of this investigation is the mandatory restrictions framework.

70 Mandatory restrictions on the use of electricity may be imposed by a jurisdiction as a means of controlling demand and averting a situation where there is insufficient generation capacity to meet demand, particularly in situations where involuntary load shedding is or would otherwise be necessary. These restrictions may come into effect during periods of extreme demand or instances where a sudden decrease in available capacity occurs.

71 When restrictions are imposed on a region, electricity users are requested to reduce demand (and large electricity users may be required to reduce demand). AEMO is then required to call for sufficient capacity contracts ("restriction offers") equal to the estimated reduction in demand due to the restrictions. If demand is higher than anticipated and this contracted capacity has to be dispatched, it is dispatched at the market price cap (MPC). This creates a risk of tripping the cumulative price threshold and triggering an administered price period, thereby muting scarcity signals and demand response incentives at a time when they are most needed.

72 The rationale for introducing the mandatory restrictions framework was to preserve price signals during a period where demand is reduced as a result of restrictions and provide an incentive for generators to invest and increase supply. However, the application of mandatory restrictions may result in outcomes that would leave market customers worse off than if the generator contracting and pricing procedures had not been used. For example, errors in the estimation of demand reduction due to restrictions may result in price outcomes that are on average higher than would have occurred had the estimate of demand reduction due to restrictions been accurate. Alternatively, market customers (and their consumers) may have to bear AEMO’s costs of contracting generation capacity even if it is not ultimately required due to the level of demand response achieved in response to restrictions.

73 The Commission considers that the mandatory restrictions framework should be removed from the NER. The Commission notes that the market context has significantly changed since the mandatory restrictions provisions were included in 2001 - for example, there is significantly more technical and institutional capacity to reduce demand in response to high prices and greater willingness to use the reliability and emergency reserve trader to address anticipated shortfalls.

74 The mandatory restrictions framework has not been used to date and, given the difficulty in accurately estimating the level of demand reduction that will be achieved by restrictions, the Commission considers that the risk of unintended pricing outcomes is high. The Commission notes that jurisdictions will still have the ability under state-based legislation to impose mandatory restrictions. However, the Commission considers it preferable - if restrictions are imposed - to allow the market to operate as normal, enabling participants to respond efficiently in real time to price signals that accurately reflect the supply demand balance. The alternative approach considered in the consultation paper (i.e. using intervention pricing in place of the current capacity contracting system) is not supported on the basis that it is subject to many of the same forecasting challenges as the current mandatory restrictions framework. Finally, the ongoing allocation of AEMO resources to maintain this framework is not justifiable.

75 **Recommendation:** AEMO to submit a rule change request to remove the mandatory restrictions framework from the NER.

76 **Final report**

77 As noted above, while this is the final report for this part of the investigation, consultation on the two draft determinations published in conjunction with this report will continue in accordance with normal rule making procedure. The Commission also notes that when it

receives the rule change requests it has recommended, there will be multiple opportunities for stakeholder consultation on the issues raised by the Commission's recommendations, as those rule change requests are progressed.

CONTENTS

TABLES

FIGURES

1 INTRODUCTION

The changing generation mix in the NEM has been characterised by the connection of weather-dependent generating technologies, such as wind and solar, and the retirement of more conventional generating technologies, such as coal. This transformation has implications for the management of power system security that need to be considered. In particular, recent retirements of some synchronous generating units and many other synchronous generators operating for fewer hours each day have resulted in substantially reduced levels of system strength in some parts of the power system.

In response to this change, in September 2017 the AEMC introduced a requirement in the NER for TNSPs to maintain minimum levels of system strength in their respective networks where AEMO identifies that there is, or is likely to be, a shortfall with respect to the minimum level required to maintain a secure power system. South Australia is the only region in the NEM in which AEMO has declared there to be a shortfall in system strength. In response to this declaration, ElectraNet determined that the least cost means of addressing the shortfall is to install a number of synchronous condensers at various locations in the network. These synchronous condensers are expected to be installed in two stages over the course of 2020.

Until such time as the synchronous condensers are installed, AEMO has been issuing directions to specific generators in South Australia to remain online for the purposes of providing system strength. At the time that ElectraNet determined its approach to addressing the system strength shortfall, there had only been a handful of directions issued to generators in South Australia. However, since that time, the number and frequency of directions has increased markedly, accounting for up to a third of all operating hours in 2018. As at 31 July 2019, 267 system strength directions have been issued in South Australia in the period since April 2017.

In November 2018, AEMO issued a direction to a generator in Victoria to maintain system strength. This was the first time a system strength direction had been issued in a region other than South Australia.

The increasing use of interventions in South Australia and Victoria has drawn attention to a number of issues regarding the interventions framework set out in the NER. The interventions framework comprises "directions", "instructions" and the Reliability and Emergency Reserve Trader (RERT).[3]

In response to concerns about increasingly frequent reliance on interventions, and in accordance with a recommendation made in the Reliability Frameworks Review final report,[4] the Australian Energy Market Commission (AEMC or Commission) commenced this

3 Directions and instructions are both issued under clause 4.8.9 of the NER. "Direction" is defined in chapter 10 of the NER as having "the meaning given in clause 4.8.9(a1)(1)". The equivalent definition for instructions refers to a "clause 4.8.9 instruction" which is defined as having "the meaning given in clause 4.8.9(a1)(2)". In this report, "clause 4.8.9 instructions" are referred to henceforth as "instructions". It is noted that "direction" is also a term used in section 116 of the National Electricity Law. While not defined in the NEL, "direction" in section 116 of the NEL has a broader meaning than in the NER and encompasses both directions, as defined in the NER, and clause 4.8.9 instructions.

4 AEMC, Reliability Frameworks Review - Final Report, July 2018

investigation into the regulatory frameworks that govern the use of interventions in the National Electricity Market (NEM).

The AEMC also received four separate rule change requests from AEMO relating to a number of issues with the design of the current interventions framework. Two of these rule change requests raise important issues and as such consultation on them commenced as part of this investigation. The AEMC has published draft determinations with respect to these rule change requests, which are available on the AEMC website.[5]

The other two rule change requests have been dealt with independently of this investigation as they involved issues that are machinery in nature and uncontroversial. These two rule changes were consolidated and progressed using an expedited process. A final determination on these rule change requests was made on 30 May 2019 and is also available on the AEMC website.[6]

1.1 Purpose of this investigation

The purpose of this investigation is to explore potential changes to regulatory frameworks which may be required to meet the challenges created by a changing generation mix, resulting impacts on system security, and AEMO's increasing use of interventions to manage system security.

Issues relating to the interventions framework were identified in the AEMC's Reliability Frameworks Review Final Report as warranting further investigation. That report acknowledged that intervention mechanisms are an important feature of the market design, allowing AEMO to intervene in the market (as a last resort) when such action is required to maintain reliability or security. However, the report also identified that the increasing use of directions and intervention pricing is impacting the energy and compensation costs borne by consumers, and may be distorting price signals to investors. It recommended that the Commission:

- consider the intervention mechanisms from the perspective of how interventions occur and operate as a suite of mechanisms;
- review the current intervention pricing and compensation framework to make sure that it is sufficiently nuanced to respond efficiently to the variety of contexts in which AEMO intervention events occur, and
- progress any rule change requests submitted by AEMO on the intervention pricing and compensation framework in conjunction with this investigation.

This investigation actions the recommendations made in that report as well as examining a number of other issues relating to the interventions framework more broadly. It builds on the work of the Intervention Pricing Working Group (IPWG) which was established by AEMO when unexpected outcomes from the implementation of intervention pricing prompted AEMO

5 See https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader and https://www.aemc.gov.au/rule-changes/threshold-participant-compensation-following-market-intervention

6 AEMC, Rule change: Intervention compensation and settlement processes, available at: https://www.aemc.gov.au/rule-changes/intervention-compensation-and-settlement-processes

to conduct a review of intervention pricing. As part of that review, AEMO commissioned a report by SW Advisory and Endgame Economics.[7] It also established the IPWG to consider the recommendations in that report as well as a number of other issues which are now being progressed by the AEMO rule change requests.[8] The AEMC's investigation has drawn upon the work undertaken by AEMO and the IPWG.

1.2 Scope of this investigation

The AEMC has split its consideration of this investigation into two parts.

- Part A – Interventions and compensation

The AEMC's investigation explores issues associated with the current interventions and compensation frameworks in the NER and identifies potential changes that could improve the efficiency and effectiveness of the frameworks. The investigation considers the application of the interventions framework to the maintenance of system security as well as reliability, and the hierarchy, or sequence of use, of the three different intervention mechanisms (RERT, directions and instructions).

Part A is the focus of this report which sets out the Commission's recommendations on the design and application of the interventions framework in the NER. This report is accompanied by draft determinations made by the Commission with respect to the two remaining rule change requests of the four that were submitted by AEMO.

- Part B – System strength and other services

The Commission is also considering whether improvements can be made to the minimum system strength and inertia frameworks to more effectively and efficiently identify and address shortfalls in system strength and inertia as they arise in NEM regions.

This part of the investigation will now be progressed separately. As part of this work, the Commission is taking the opportunity to seek stakeholder feedback on the minimum system strength and inertia frameworks with the intention of making them as effective and efficient as possible. The application of these frameworks should obviate the need for AEMO to maintain system security by intervening in the operation of the market. However, the Commission intends to explore whether adjustments could be made to these frameworks to improve the flexibility with which they can be applied to address issues as they begin to emerge in other NEM regions. A more flexible framework may limit the need for the use of interventions, thereby reducing costs to consumers and minimising market distortion.

Part B is not the focus of this report. The Commission intends to publish recommendations on any proposed changes to the minimum system strength and inertia frameworks in October 2019. For any proposed changes, the AEMC will:

- identify the reasons for the proposed change and likely impacts on the NEM and consumers, and

7 SW Advisory and Endgame Economics, Review of Intervention Pricing - Final Report prepared for AEMO, 4 October 2017.

8 Terms of reference for the IPWG, the SW Advisory report and meeting minutes are available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group. The SW Advisory Report is available in the meeting pack for meeting 1

- describe pathways to implementation, including timing, possible interim stages and any necessary changes to the NER.

Recommendations may include possible changes to policy frameworks and potential future rule change requests, as well as any further actions where required.

1.3 Related rule change requests

As noted earlier, unexpected outcomes from the implementation of intervention pricing prompted AEMO to conduct a review of intervention pricing. As a result of that work, AEMO has to date submitted four rule change requests relating to the interventions framework. AEMO has indicated it intends to submit further rule change requests relating to the interventions framework in due course.

In conjunction with this final report, the Commission has made draft determinations with respect to two of these rule changes requests. The draft determinations are to:

- apply the $5,000 compensation threshold for additional compensation claims by directed participants to each direction, rather than to each trading interval; the draft determination makes no changes to the threshold as it applies to affected participants
- extend the application of the regional reference node (RRN) test to the RERT, preserve the current approach whereby intervention pricing does not apply where a direction (or the RERT) is to address a localised issue relating to a service already traded in the market (energy or FCAS) when the issue arises in part of the network that is remote from the RRN, and clarify that intervention pricing does not apply where the direction (or the RERT) is to address a shortfall of a service that is not traded in the market (system strength, inertia, etc).

The remaining two rule change requests submitted by AEMO concern administrative issues which do not raise larger questions about the interventions framework. Issues addressed include whether the timeframes for interventions and settlements should be aligned in order to streamline cost recovery processes[9], and whether the deadline for submitting compensation claims should be extended from 7 to 15 business days.[10] These rule change requests were consolidated and expedited as non-controversial. A final determination was published on 30 May 2019 which streamlines the cost recovery process by aligning the timetables for compensation and settlement following an intervention, and extends the deadline for participants to make additional claims following an intervention which would allow participants more time to assess the impact of intervention events.[11]

1.4 Progress to date

The AEMC published a consultation paper on its investigation into intervention mechanisms and system strength in the NEM on 4 April 2019. The consultation paper:

9 AEMO's rule change request is available at: https://www.aemc.gov.au/rule-changes/alignment-intervention-compensation-and-settlement-timetables

10 AEMO's rule change request is available at https://www.aemc.gov.au/rule-changes/deadlines-additional-compensation-claims-following-market-intervention

11 AEMC, *Intervention compensation and settlement processes - final determination*, 30 May 2019.

- considered the efficiency and appropriateness of the interventions and compensation frameworks, including the hierarchy of interventions and the use of intervention pricing
- described issues related to the use of the interventions framework in managing power system security
- set out a summary of, and a background to, two of the four rule change requests submitted by AEMO
- identified a number of questions and issues to assist the AEMC in its approach to the investigation and to facilitate consultation on the rule change requests
- examined issues associated with the minimum system strength and inertia frameworks
- sought stakeholder views on the scope and materiality of each of the issues.

Written submissions on the paper closed on 16 May 2019 and are available on the AEMC website. A summary of stakeholder submissions is also available.[12]

1.5 Investigation timeline

The timeline for this investigation and related rule determinations is set out in table 1.1 below. A separate report on system strength issues is to be published in October 2019 and will be the subject of further consultation.

Table 1.1: Review timeline

ITEM	DATE
Publication of consultation paper	4 April 2019
Close of submissions on consultation paper	16 May 2019
Publication of final report and two draft determinations	15 August 2019
Close of submissions on draft determinations	26 September 2019
Publication of final determinations	7 November 2019

1.6 Structure of this report

The remainder of this report is structured as follows:

- Chapter 2 provides an overview of the intervention and compensation framework and outlines the Commission's assessment approach.
- Chapter 3 sets out the Commission's approach with respect to intervention pricing and the regional reference node test, including the approach in the draft determination made on AEMO's rule change request relating to the regional reference node test.

12 The summary of submissions is available at: https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem

- Chapter 4 sets out the Commission's recommendations on the compensation frameworks that apply to directed and affected participants, and outlines the approach in the draft determination made on AEMO's rule change request to apply the $5,000 threshold to each intervention event, rather than each trading interval.
- Chapter 5 explores the hierarchy of and principles for interventions mechanisms.
- Chapter 6 considers the proposal to automatically apply the market price cap whenever the RERT is activated.
- Chapter 7 explores the merit of the mandatory restrictions framework.

2 BACKGROUND AND ASSESSMENT FRAMEWORK

This chapter sets out the nature of the recent interventions, provides an overview of the intervention and compensation frameworks, and outlines the Commission's assessment approach.

2.1 Background

The generation mix in South Australia is changing rapidly. The market share of large scale asynchronous generators (predominantly wind) has grown quickly, while operational demand is falling due to the increased penetration of residential scale photovoltaic systems. Some synchronous generators (e.g. Northern Power) have already retired and other synchronous generating units are expected to withdraw from the market in the near term.[13]

When demand is low to moderate and output from wind generation is high, spot prices in South Australia fall to low levels, making it difficult for gas fired generators to earn sufficient revenue to recover their short run costs. As a result, synchronous generators may bid unavailable, thus reducing the number of synchronous generating units operating during such periods. This has resulted in low levels of fault current, a service that has historically been provided by synchronous generators and is not typically provided by asynchronous generators. This has resulted in reduced levels of system strength.

System strength refers to the relative change in voltage for a change in load or generation at a connection point. Low levels of system strength can jeopardise the ability of generators to operate correctly, thus impacting system security. System strength is usually measured by the available fault current at a given location or by the short circuit ratio.[14]

ElectraNet intends to address the shortfall in system strength in South Australia through the construction of synchronous condensers, in accordance with its obligation under the *Managing power system fault levels* rule made by the Commission in September 2017.[15]

In the meantime, AEMO has been intervening in the operation of the market through the issuance of directions to synchronous generators to maintain minimum levels of system strength. AEMO first directed generators to provide system strength in South Australia in April 2017. The second occasion was in September 2017 and, since then, directions have become increasingly frequent. As at 31 July 2019, AEMO had issued 267 system strength directions.[16]

During 2018, directions were in place for around 30 per cent of the time. However, as shown below in figure 2.1, the percentage of time during which directions were in place fell significantly in the first quarter of 2019 to 5.4 per cent. This was due to higher synchronous

13 For example, Torrens Island A power station will be progressively mothballed between 2019 and 2021: AEMO generator information page available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-andforecasting/Generation-information

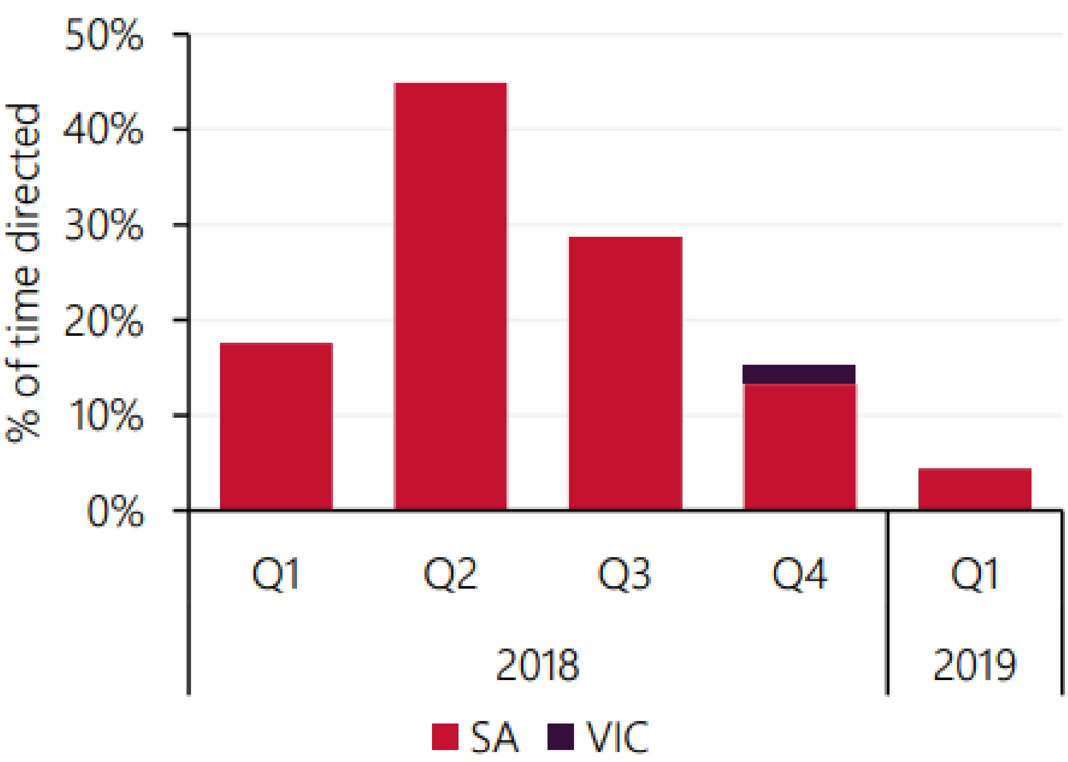
14 System strength service is defined in chapter 10 of the NER as "a service for the provision of a contribution to the three-phase fault level" at a given location in the transmission network.

15 AEMC, *Managing power system fault levels, Rule Determination*, 2017

16 Data provided by AEMO.

generator availability, influenced by periods of high demand (which is typical for summer) and expectations of comparatively higher spot prices.[17]

Figure 2.1: Directions for system security in South Australia and Victoria



Source: AEMO, Quarterly Energy Dynamics - Q1 2019, p. 28.

Note: The figure refers to system security directions. These were system strength directions in South Australia. In Victoria, one system strength direction was issued in November 2018 together with a small number of directions for voltage control.

AEMO advises that in the second quarter of 2019, directions were in place for 13.3 per cent of the time. Likely drivers for this increase relative to the first quarter of 2019 include reduced operational demand in South Australia, following the end of summer, and increased wind generation. However, unplanned coal outages in NSW resulted in higher levels of gas output in South Australia, which would have tended to suppress the number of directions relative to levels observed in the second quarter of 2018.

17 AEMO, *Quarterly Energy Dynamics - Q1 2019*, May 2019, p. 23.

The increasing use of directions in South Australia has drawn attention to a number of issues regarding the interventions framework, including the impact of directions and intervention pricing on spot prices and investment signals, and the impact on consumers of both intervention pricing and compensation payments to directed and affected participants. Further explanation of these issues is provided in section 2.2.

In addition to the directions being issued in South Australia, system strength related issues are emerging in other regions of the NEM. As such, this investigation is also considing whether the time frames and level of flexibility in the system strength framework in the NER is sufficient to deliver optimal outcomes when addressing emerging system strength shortfalls as they arise in NEM regions other than South Australia. However, this work is not the focus of this report. The Commission intends to publish the next stage of this investigation in October 2019, which will explore potential changes to the system strength framework in further detail.

2.2 The interventions framework

The purpose of interventions is to help maintain and/or re-establish the reliability and security of the NEM when regulatory processes or market responses have not delivered desired outcomes. Reliability means that the power system has an adequate amount of capacity (generation, high voltage transmission network and demand response) to meet consumer needs. This is distinct from the concept of security whereby a secure power system is one that operates within defined technical limits.

The reliability framework, which includes the reliability settings such as the market price cap, is designed to deliver reliability consistent with the level of the reliability standard set out in clause 3.9.3C of the NER.[18] However, in operating the power system AEMO is expected to try to avoid any unserved energy (i.e. load shedding) in real time,[19] including by using the intervention mechanisms available to it if necessary.

AEMO also has a responsibility to maintain and improve power system security,[20] defined in chapter 10 of the NER as the safe scheduling, operation and control of the power system on a continuous basis. The secure operation of the system involves compliance with technical parameters relating to issues such as frequency, voltage control and system strength even after a credible contingency has occurred, such as the loss of a single generating unit or transmission line.

Intervention mechanisms enable AEMO to deal with actual or potential supply shortages or system security issues by intervening in the market in certain limited circumstances. Intervention mechanisms are an acknowledged and important feature of the market design. However, the use of such mechanisms requires careful consideration as to the flow-on effects for investment signals and investor confidence, as well as costs to consumers.

18 The reliability standard for generation and inter-regional transmission is a maximum expected unserved energy (USE) in a region of 0.002 per cent of total energy demanded in that region for a given financial year.

19 See Clause 4.2.7 of the NER – AEMO is required to keep the system operating to a reliable operating state which implies no unserved energy.

20 See s. 49 of the National Electricity Law 1996 and clause 4.1.1(b) of the NER.

The RERT, directions and instructions are the three key intervention mechanisms available to maintain or re-establish power system security and/or reliability.[21] A further mechanism, known as "mandatory restrictions", is another means by which AEMO, acting in concert with a jurisdiction, can intervene in the market. Set out in rule 3.12A of the NER, mandatory restrictions are a form of market intervention mechanism that can be imposed by a jurisdiction in instances where a significant supply demand imbalance is forecast. If this occurs, AEMO then uses capacity contracting and pricing arrangements to manage market impacts. These provisions have not been used since their inclusion in the NER.

2.2.1 The RERT

The Reliability and Emergency Reserve Trader (RERT) allows AEMO to contract for reserves (generation or demand side capacity that is not otherwise available to the market) ahead of a period when available supply is projected to be insufficient to meet the reliability standard.[22] At present, AEMO can contract for reserves from three hours to nine months ahead of the projected shortfall. (From 26 March 2020, when the Enhanced RERT rule commences, it will be possible to contract for reserves 12 months ahead of the projected shortfall.[23]) AEMO can dispatch these reserves to ensure reliability of supply and maintain power system security, where practicable.[24] AEMO may contract only with resources that are "out-of-market". Examples include a back-up diesel generator or emergency demand response.

From a regulatory perspective, the RERT is a voluntary mechanism involving a tender process and/or pre-agreed RERT panel process. It is a tool that is arranged in advance (i.e. contracts procured and/or RERT panel established in advance) and dispatched in real or operational time frames.

AEMO's ability to determine whether to procure reserves, and its determination of the amount of those reserves, is limited by a number of requirements.[25] A number of these are also relevant to AEMO's ability to dispatch the RERT. Broadly speaking, AEMO is required to seek to minimise market distortion and maximise the effectiveness of the RERT at least cost to consumers.[26]

When the RERT is activated (or when AEMO issues a direction under clause 4.8.9 – discussed further below), AEMO is required to set prices to the value which AEMO, in its reasonable opinion, considers would have applied had the RERT activation or direction not occurred.[27] This practice, known as "intervention pricing", is applied whenever the RERT is activated (whereas directions relating to localised issues that are remote from the RRN do not trigger

21 A distinction is being drawn for the purposes of the discussion in this chapter between the general term of intervention mechanism and the legal definition of AEMO intervention event as defined in Chapter 10 of the rules. An "AEMO intervention event" encompasses the RERT and directions, but not instructions.

22 Where the RERT has been procured for reliability purposes, it can also then be used - where practicable - for the maintenance of power system security. Clause 3.20.2 of the NER. See also section 7 of the RERT guidelines developed and published by the Reliability Panel under clause 3.20.8 of the NER.

23 AEMC, *Enhancement to the Reliability and Emergency Reserve Trader, Rule Determination,* May 2019.

24 Clause 3.20.7(a) of the NER.

25 The NER provide the high-level framework within which AEMO may procure and dispatch the RERT. Rule 3.20 of the NER.

26 Clause 3.20.2(b) of the NER.

27 Clause 3.9.3 of the NER.

the requirement for intervention pricing). Intervention pricing is meant to preserve market price signals to minimise the distortionary effect of the RERT activation or direction.

AEMO has submitted a rule change request which proposes that the approach applied to directions also apply to the RERT - namely, that where the RERT is activated to address a localised issue that is remote from the RRN, intervention pricing should not apply. AEMO's rule change request also proposes changes to the wording of the provision in order to increase clarity. The Commission has made a draft determination with respect to this rule change request that will extend the application to the RERT of the RRN test (which currently determines whether to apply intervention pricing in connection with a direction). The wording of the test has also been significantly changed to make clear the circumstances in which intervention pricing should and should not be implemented. This is discussed further in chapter 3.

2.2.2 Directions

AEMO is permitted under the NER to intervene in the market by issuing directions if it is satisfied that it is necessary to maintain or re-establish the power system to a secure, satisfactory or reliable operating state.[28]

If there is a risk to the secure or reliable operation of the power system, AEMO could for example direct:

- a scheduled generator or market generating unit to increase (or decrease) their output
- a scheduled load to decrease (or increase) consumption
- a scheduled network service to take certain action unless (in the reasonable opinion of the Registered Participant that is being directed) it would be a hazard to public safety, materially risk damaging equipment or contravene any other law.[29]

To minimise wider market effects associated with a direction, AEMO can also impose a "counteraction" to offset the impact of a direction. Under NER clause 4.8.9(h)(3), AEMO may apply a counteraction constraint on a selected market participant to minimise the number of affected participants and the effect on interconnector flows during an AEMO intervention event (defined as comprising the RERT and directions). For example, AEMO may direct a generator to synchronise to come to minimum load and then follow dispatch targets in order to ensure there is sufficient headroom in the system as demand increases, thereby relieving a LOR condition. To reduce the effect of the direction on interconnector flows and the number of affected participants, AEMO may constrain down output from another generator to offset the impact of the direction.

If the counteraction does not perfectly offset the effect of the direction, or where other constraints in NEMDE operate to alter dispatch targets, other participants may also have their dispatch targets affected as a result of the direction (or RERT activation). The party which is the subject of the counteraction becomes an "affected participant", as do any other parties

28 Clause 4.8.9 of the NER.

29 Clause 4.8.9(c) of the NER.

whose dispatch targets are affected by the direction (or RERT activation) and subsequent NEMDE dispatch process.

In contrast to the RERT, directions are a non-voluntary regulatory tool: a registered participant must use its reasonable endeavours to comply with a direction regardless of the financial implications unless to do so would, in their reasonable opinion, be a hazard to public safety, materially risk damaging equipment, or contravene any other law.[30]

As with the RERT, AEMO is also required to set prices during directions to the value which AEMO, in its reasonable opinion, considers would have applied had the intervention event not occurred.[31] However, some directions do not trigger the application of intervention pricing. Under the RRN test, intervention pricing is not to be applied when a direction relates only to an isolated part of the network that is remote from the RRN.[32]

2.2.3 Instructions

An instruction differs from a direction in the nature of the action taken. The NER provide that AEMO is taken to have issued a direction where it requires a registered participant to take action in relation to scheduled plant or a market generating unit. Where the action to be taken by the registered participant does not relate to a scheduled plant or market generating unit, AEMO is taken to have issued a "clause 4.8.9 instruction" (referred to in this report as "instructions").[33] AEMO may issue a direction or instruction if it is satisfied that it is necessary to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state.[34]

Instructions generally involve AEMO requiring a network service provider or a large energy user to temporarily disconnect its load or reduce demand if there is a risk to the secure or reliable operation of the power system.[35] AEMO may also instruct a network service provider to shed and restore load consistent with schedules provided by the relevant state government.[36]

The trigger for AEMO's use of instructions is the same as for directions. AEMO may issue an instruction to registered participants where it is necessary to do so to maintain or return the power system to a secure, satisfactory or reliable operating state.[37] As an instruction typically involves load shedding, it is fundamentally a mechanism for maintaining or returning the system to a secure operating state.

30 ibid.

31 Clause 3.9.3(b) of the NER.

32 NER, clause 3.9.3(d) provides that normal pricing processes should continue if a direction given to a plant located at the regional reference node would not have avoided the need for any of the directions issued by AEMO that constituted the intervention event.

33 NER, clause 4.8.9(a1)(2).

34 Clause 4.8.9(a) and (a1) of the NER

35 This only applies to large users who are registered participants.

36 Jurisdictions manage the impact of instructions in advance by providing a load schedule, including sensitive loads, which sets out the order in which AEMO may shed load under rule 4.8: see clause 4.3.2(f) of the NER.

37 Subject to complying with the sequence of steps set out in clause 3.8.14 during times of supply scarcity (i.e. activating the RERT, if it has been procured, ahead of using directions or instructions).

Instructions oblige instructed parties to use reasonable endeavours to comply. As with directions, they are a non-voluntary form of intervention.[38]

In contrast to the RERT and directions, intervention pricing is not triggered in relation to instructions to shed load issued under clause 4.8.9. Instead, AEMO sets the regional price to the market price cap when involuntary load shedding occurs.[39] This can be considered a form of intervention pricing in its broader sense, but is not intervention pricing as defined in the NER.

2.3 Assessment framework

The overarching objective guiding the Commission's approach to this investigation is the national electricity objective (NEO). The Commission has also set out a number of principles to guide the development of recommendations on potential changes to the interventions, system strength and inertia frameworks.

2.3.1 NEO assessment

In undertaking this investigation, the Commission has been guided by the National Electricity Objective (NEO). The Commission's assessment of the rule change requests has considered whether the proposed rules promote the NEO which is set out in 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:
>
> 1. price, quality, safety, reliability and security of supply of electricity; and
> 2. the reliability, safety and security of the national electricity system.

The Commission considers that the relevant aspects of the NEO raised by the investigation and the related rule change requests are the efficient investment in electricity services with respect to the security of the national electricity system and the price of supply of electricity.

2.3.2 Assessment approach

The Commission considers that intervention-based approaches, however well designed, are likely to be a second-best alternative to well-functioning markets at promoting economic efficiency in the long-term interests of consumers. Markets are generally the most efficient mechanism to further the interests of consumers through allowing efficient price discovery and production decisions based on competitive market dynamics. By allocating risks to market participants, markets provide financial incentives to make efficient decisions and provide incentives for innovation, to the benefit of consumers.

38 Under clause 4.8.9(c), a Registered Participant must use its reasonable endeavours to comply with a direction or clause 4.8.9 instruction unless to do so would, in the Registered Participant's reasonable opinion, be a hazard to public safety, or materially risk damaging equipment, or contravene any other law. This clause is classified as a civil penalty provision. See also clause 4.8.9(c1).

39 Clause 3.9.2(e)(1) of the NER.

Indeed, as noted earlier, the NER include a principle that AEMO decision-making should be minimised to allow market participants the greatest amount of commercial freedom to decide how they will operate in the market.[40] Consistent with this, the AEMC considers interventions to be a last resort mechanism.

Nonetheless, intervention-based approaches remain an important tool available to AEMO to help ensure reliability and system security. This is reflected in previous Commission decisions to remove sunset clauses in the NER and retain such measures indefinitely. Such measures may be particularly important when new frameworks are yet to be developed or fully implemented to support system security as the energy market transition unfolds.

The intervention pricing framework in the NER is intended to maintain the efficiency of price signals that would otherwise be provided through the efficient operation of the market. However, a key question for consideration is when the application of the intervention pricing framework is appropriate.

The Commission has set out a number of principles to guide the development of recommendations on potential changes to the interventions, system strength and inertia frameworks. In addition to the NEO, these principles, together with those set out in Chapters 5 and 6 of the consultation paper, have been used to guide the Commission's assessment of the rule change requests.

1. **Appropriate risk allocation:** Regulatory and market arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of providing a secure supply of electricity. Risk allocation and the accountability for investment and operational decisions should rest with those parties best placed to manage them. Through the use of interventions, risks are more likely to be borne by consumers. Solutions that are better able to allocate risks to market participants such as businesses who are better able to manage them are preferred where practicable.
2. **Efficiency:** The costs associated with the provision of energy resources should be assessed against the value to consumers of having a secure supply. Intervention frameworks should seek to minimise distortions in order to promote the effective functioning of the market.
3. **Flexibility:** Regulatory arrangements must be flexible to changing market and external conditions. They must be able to remain effective in achieving security outcomes over the long-term in a changing market environment. Regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions. They should be effective in facilitating security outcomes where it is needed, while not imposing undue market or compliance costs on other areas.

40 See clause 3.1.4(a)(1) of the NER.

4. **Transparency and predictability:** Interventions frameworks should promote transparency as well as being predictable, so that market participants can make efficient investment and operational decisions.

The consultation paper set out these principles and sought stakeholder views on them. Several stakeholders expressed support for the principles,[41] and others suggested that the AEMC have regard for a number of other principles. These suggested principles, and the Commission's response, are set out in Table 2.1.

Table 2.1: **Stakeholders' proposed principles**

PROPOSED PRINCIPLE	AEMC RESPONSE
Ensure regulatory and commercial outcomes are aligned with good engineering practice.[1]	The AEMC supports this view. While market and regulatory frameworks should be designed to maximise efficient outcomes, the Commission considers that this should not come at the expense of a safe and secure power system.
Any change to interventions, system strength and inertia frameworks should be technology neutral and designed so that no one solution, or type of provider for such services, is discriminated against or competitively disadvantaged.[2]	The AEMC supports this view. Regulatory arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind.
Any changes to interventions, system strength and inertia frameworks should be designed so that the value to each service or solution is clearly signalled. Using one price to signal multiple value elements should be avoided.[2]	The AEMC supports this view and considers that it supports the achievement of principles 1, 2 and 4.
Regardless of the mechanism used to procure a response, there should be the same, or very similar, outcomes for participants.[3]	The AEMC supports this view but notes that each mechanism has different uses and design features such that absolute consistency of outcomes may not be appropriate.
Efficiency should not be framed simply as lowering the cost of the provision of services in the short run, given that inadequate rewards for providing energy services affect the sustainability of the market.[4]	The AEMC considers that mechanisms should be designed with regard for promoting efficiency in both the short and long term.

41 Submissions on the consultation paper are available at: https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem

PROPOSED PRINCIPLE	AEMC RESPONSE
Explicit reference should be made to the value of transparency as a means to keep interventions and intervention frameworks accountable to consumers.[5]	The AEMC supports this view. Transparency in the interventions framework is of particular importance to consumers, as it is consumers that ultimately bear the costs of compensation.

Note: [1] Energy Queensland, submission on the consultation paper, p. 2. [2] TasNetworks, submission on the consultation paper, p. 3. [3] Powerlink, submission on the consultation paper, p. 3. [4] Engie, submission on the consultation paper, p. 2. [5] PIAC, submission on the consultation paper, p. 4.

3 INTERVENTION PRICING AND THE REGIONAL REFERENCE NODE TEST

BOX 1: SUMMARY

Intervention pricing is a practice intended to minimise market distortion when AEMO intervenes in the market. It does this by preserving price signals at the level which, in AEMO's reasonable opinion, they would have been at had the intervention event not occurred.

Under the current rules, AEMO applies intervention pricing whenever it activates the RERT. By contrast, when AEMO issues a direction, it has to apply the "regional reference node (RRN) test" to determine whether to apply intervention pricing. Broadly, the objective of the test is to determine whether there is a region-wide scarcity of the service that is the subject of the direction, or whether the problem being fixed is localised. If the problem is region-wide, then it will be important to preserve price signals and the incentive they create for investment. This is the aim of intervention pricing.

One of the rule change requests submitted by AEMO proposes to change the wording of the RRN test and to extend its reach so that it encompasses the RERT as well as directions. This would have the effect of limiting the use of intervention pricing to those instances where the RERT is activated in response to a region-wide rather than localised issue. The request also proposes to change the wording of the RRN test to improve clarity.

The Commission considers that the RRN test should also consider the nature of the service that is being obtained by the intervention, not just whether the issue is localised or region-wide. For example, the recent directions in South Australia have been issued by AEMO for the purposes of obtaining system strength. However, the application of intervention pricing in these instances has the effect of maintaining a scarcity signal for energy. This may encourage new entrants to invest in additional capacity, regardless of whether those investments support or undermine system strength.

In order to reduce distorted investment signals and higher than necessary costs to consumers, the Commission has made a draft determination which amends the RRN test to remove the application of intervention pricing where the intervention is intended to address a shortfall of a service that is not traded in the market (system strength, inertia, etc). As with the current approach, the test will make clear that intervention pricing will also not apply if the service being obtained is a market traded service but the issue is localised only, and in a part of the network which, due to a network or other constraint, does not include the RRN.

Draft determination 1: The Commission has published a draft determination which changes the wording of the RRN test to clarify the circumstances in which intervention pricing should apply. The more preferable draft rule removes the application of intervention pricing in instances where a direction has been issued for the purpose of addressing a shortfall in a *service that is not traded in the market. The more preferable draft rule also extends the reach of the test to encompass the RERT, thereby creating a consistent approach to intervention pricing as between directions and the RERT.*

This chapter examines issues relating to the application of intervention pricing during intervention events. It describes:

- the existing arrangements in the NER and the rationale for these arrangements
- the issues raised in the consultation paper and stakeholders' views on these issues
- the Commission's analysis and recommendations.

3.1 Introduction

As outlined in chapter 2, intervention pricing is a practice which is intended to minimise market distortion when AEMO intervenes in the market by activating the reliability and emergency reserve trader (RERT) or issuing a direction. It does this by preserving price signals at the level which, in AEMO's reasonable opinion, they would have been at but for the intervention event.

Intervention pricing determines the price at which the market clears during an "AEMO intervention event"[42], while compensation is a separate process and is paid only to certain parties – those who are directed to provide services and those who are affected (i.e. dispatched differently) due to the direction. Compensation is payable regardless of whether intervention pricing is implemented. The compensation framework is discussed further in chapter 4.

Under the current rules, AEMO implements intervention pricing whenever it activates the RERT. By contrast, when AEMO issues a direction, it has to apply the "regional reference node (RRN) test" to determine whether to apply intervention pricing. Intervention pricing does not apply in connection with clause 4.8.9 instructions.[43] Instead, AEMO sets the regional reference price to the market price cap when involuntary load shedding occurs.[44] This can be considered a form of intervention pricing in its broader sense, but is not intervention pricing as defined in the NER.

The RRN test asks whether a direction issued to a plant at the RRN would have avoided the need for the actual direction issued. If the answer is yes, AEMO should implement intervention pricing. If the answer is no, AEMO should not implement intervention pricing. For example, if directing a plant near Brisbane would not have solved a problem in far north Queensland, there is no value in preserving price signals at the RRN because the problem is localised and does not signal a region-wide scarcity for which market price signals should be preserved. As a result, intervention pricing is not applied.

42 Defined in chapter 10 of the NER as issuing a direction or exercising the RERT. Clause 4.8.9 instructions are not included in the definition of an AEMO intervention event.

43 Referred to in this paper as "instructions".

44 Clause 3.9.2(e)(1) of the NER.

AEMO has submitted a rule change request to extend the reach of the RRN test so that it encompasses the RERT as well as directions. This is designed to ensure that intervention pricing is not used in connection with the RERT in cases where there is no economic rationale for doing so. The request also proposes to change the wording of the test to improve clarity as the test has proved difficult to apply in practice.

The consultation paper examined the rationale for intervention pricing and experience to date with its implementation. It considered whether the use of intervention pricing in connection with system strength directions is causing – rather than reducing – market distortion, sending inefficient signals to investors and putting upward pressure on wholesale prices.

In discussing the RRN test rule change request, the consultation paper considered whether an alternative approach to the test warrants consideration in order to reduce inefficient outcomes. In particular, whether intervention pricing should only apply when there is scarcity of a market traded commodity – meaning that there is a relevant market price signal to preserve. These issues are explored further below.

3.2 Intervention pricing and the regional reference node test

When a relevant AEMO intervention event occurs, AEMO must set the dispatch price and ancillary services price at the value which AEMO, in its reasonable opinion, considers would have applied had the AEMO intervention event not occurred.[45] For this reason, intervention pricing is often referred to as "what if pricing" – what would the price have been if the intervention had not occurred?

AEMO determines the intervention price in accordance with an intervention pricing methodology developed under clause 3.9.3(e). As the methodology notes, the aim of intervention pricing is "to preserve the market signals that would have existed had AEMO not intervened".[46] Such signals are important, particularly in an energy-only market, as they are designed to convey to stakeholders the need for investment in additional capacity. In this way, intervention pricing seeks to minimise the market distortion that would otherwise result from the intervention.

When the intervention event comprises a direction (rather than the activation of the RERT), AEMO is required to determine whether to implement intervention pricing. Specifically, AEMO must decide whether the test set out in clause 3.9.3(d) is met. That provision states that AEMO must continue to set prices using normal processes (and not implement intervention pricing) "if a direction given to a registered participant in respect of plant at the regional reference node would not in AEMO's reasonable opinion have avoided the need for any direction which constitutes the AEMO intervention event to be issued".

This test is known as the "regional reference node test" (RRN test) and its intent has been described by a 2011 AEMO briefing paper as follows:[47]

45 Clause 3.9.3(b) of the NER. A relevant AEMO intervention event includes the activation of the RERT and the issue of directions. As noted earlier, intervention pricing is not implemented when directions apply only to isolated network areas.

46 AEMO, *Intervention Pricing Methodology*, September 2018, p. 5

47 AEMO, *Briefing Paper: Operation of the intervention Price Provisions in the National Electricity Market*, March 2011, p. 4.

> For some interventions the Rules (e.g. clause 3.9.3(d)) provide that intervention pricing is not invoked and normal price setting continues. These circumstances apply in situations where equivalent intervention in respect of plant located at the regional reference node would not have removed the need for the intervention actually given. Thus, if a generator is directed to operate its generating plant to address a supply deficiency that is confined to a part of the network that does not include the regional reference node, then intervention pricing is not invoked. This might occur for example if a network constraint was restricting supply to a remote area near the directed generator.

The origin of the test lies in changes made to the directions framework as it existed when the NEM commenced operation in 1998. At that time, the National Electricity Code (the predecessor of the NER) included separate frameworks for directions relating to breach of reliability, security and statutory obligations. Intervention pricing was implemented for directions relating to reliability but not in relation to security directions.

A review of directions was undertaken jointly by NEMMCO and NECA in 2000.[48] It made a number of relevant recommendations, including that:

- the separate arrangements for reliability, security and statutory obligation directions should be consolidated into a single common arrangement, thereby reducing the level of discretion required to be exercised by NEMMCO
- in the event of a direction, market prices should so far as practicable be set on a "what-if" basis in order to retain the appropriate price signal in the market and provide an incentive for market-based response in the future

The report further noted that, in applying "what-if" pricing, a distinction should be drawn between "regional and local directions". It stated:[49]

> A regional deficiency may be redressed by a direction to a participant anywhere in the region. Use of a what-if price for the region will therefore signal the region wide deficiency. On the other hand, a localised deficiency can only be redressed locally. As there is no regional deficiency it is inappropriate for the regional market price to indicate a shortfall... Accordingly, what-if prices will not be calculated for localised directions.

The wording of the current RRN test does not clearly articulate this original policy intent. This reflects that the distinction between region-wide and localised is not in fact clear cut. As AEMO notes in its rule change request: "Generally, directions to resolve 'local' issues do not require use of intervention pricing. However, where a local issue coincides with the regional reference node, intervention pricing is applied."[50] This reflects that, as discussed further below, there is a case to preserve price signals at the RRN where an intervention responds to a localised issue which geographically coincides with the RRN. This is because the RRN is

48 NEMMCO and NECA, *Power system directions in the National Electricity Market*, May 2000.

49 ibid, p. ii

50 AEMO, rule change request, p. 4

typically located at or close to the region's largest load centre and, as such, scarcity at the RRN - even if localised - should be signalled to the market.

The current provision's reference to "plant at the regional reference node" has prompted decisions to be made based on the physical circumstances pertaining to each case, rather than on whether the application of intervention pricing in a given case is consistent with the policy intent underpinning the test.

Given the difficulty to date in applying the test, AEMO has submitted a rule change request seeking to amend the provision in order to improve clarity and extend the reach of the test to encompass the RERT (in addition to directions). The Commission has published a draft determination on the AEMO rule change request which widens the reach of the RRN test to encompass the RERT (meaning that, rather than implementing intervention pricing every time it activates the RERT, AEMO will need to apply the RRN test before deciding whether to implement intervention pricing in connection with the RERT). The draft determination also makes significant changes to the wording of the RRN test to make clear the circumstances in which intervention pricing should apply.[51]

If AEMO decides that the RRN test is met, intervention pricing is used to determine prices for energy and market ancillary services in every dispatch interval (being five minutes in duration)[52] impacted by the intervention. An AEMO intervention event may consist of a large number of dispatch intervals and intervention pricing is applied across all these intervals, with prices calculated every five minutes.

Intervention pricing is implemented by running the NEM Dispatch Engine (NEMDE) twice – once to determine dispatch targets (the "base case target run" or "dispatch run") and once to determine intervention prices for energy and market ancillary services (the "what-if run" or "intervention pricing run"). This process happens every five minutes. Generators are dispatched in accordance with the dispatch run but prices produced by that run are ignored for the purpose of setting prices. Dispatch (and spot) prices are instead determined in accordance with the what-if run, but dispatch targets produced by that run are ignored for system operation purposes.

The dispatch levels determined in the what-if run are combined with dispatch offers to calculate a clearing price that reflects the price that AEMO considers would have prevailed had the direction not been issued.[53]

The dispatch run includes the actions taken as part of the AEMO intervention event – including the issuing of directions or the activation of the RERT, and any counteraction constraints imposed by AEMO in order to minimise the effects of the intervention.[54] The

51 The draft determination is available at https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader.

52 Clause 3.8.21(a1) of the NER.

53 This raises an important issue: where a direction responds to a system security issue, the generation mix that underpins the what-if run is unlikely to constitute an implausible counterfactual because it reflects a system that is not secure. Given this, it may not represent a sound basis for determining spot prices. This is discussed in section 3.3.

54 Clause 4.8.9(h)(3) of the NER.

what-if run does not include the direction or RERT activation, or any counteractions implemented to reduce their flow on effects.

Counteractions are designed to offset and thereby limit the wider impact of a direction. Clause 3.8.1(b)(11) of the NER requires AEMO to ensure that, as far as reasonably practical, the number of participants affected by an intervention event and the resulting effect on interconnector flows are minimised. In practice and where possible, AEMO complies with this provision by selecting generating units located in the same region as the directed generator (and, if possible, at the same power station as the directed unit, or another power station belonging to the same participant). It then constrains the dispatch of the selected generating unit/s by an amount that, as closely as practical, matches the amount of energy provided pursuant to the direction.

For example, AEMO may direct one generator to increase its output, and may constrain down another generator in order to reduce the impact of the direction on interconnector flows etc. If a counteraction is effective, then the divergence between prices in the what-if run and the dispatch run should be very small because the supply/demand balance underpinning both runs is roughly the same. In practice, however, counteractions are hard to predict and implement in such a way that they perfectly offset the impact of the direction. Counteractions are discussed further in section 5.3.

If no counteraction is imposed, and other factors hold constant, the amount of energy exported from the region where the direction was issued would likely increase or the amount imported reduce, with flow on effects for participants in other regions. When the counteraction does not perfectly offset the impact of the intervention, resulting price changes can be observed in other regions of the NEM. For example, directions issued in South Australia can impact prices in Queensland.

3.2.1 Impact of intervention pricing on wholesale prices

When an intervention event brings on additional capacity and counteractions are not implemented, the prices produced by the what-if run will generally be higher than those produced by the dispatch run. This is because the what-if run will continue to signal the price associated with the supply demand balance as it was prior to the intervention, while prices in the dispatch run will generally be lower due to the addition of generation capacity. This is not to say that the spot price is being pushed up by the intervention. Rather, intervention pricing is not allowing the price to fall in response to the additional generation coming online.

This effect can be seen in Figure 3.1 which shows that the commencement of a direction issued in September 2017 did not result in spot prices rising. However, the use of intervention pricing means that the spot price in the what-if run does not fall (as it does in the dispatch run - shown in red) in response to additional generating capacity coming online. This divergence between the what-if run and the dispatch run occurs when counteractions are not put in place to reduce the effect of the direction on the supply demand balance, or where counteractions are used but do not perfectly offset the impact of the direction.

Figure 3.1: Impact of direction on SA prices 22-25 September 2017

Source: AEMC analysis

When system strength directions bring online additional gas fired generation in South Australia and counteractions are not imposed, more energy - including a considerable volume of wind energy - is exported to other regions. As a result, higher cost generators in those other regions generate less. (This occurs automatically when NEMDE optimises dispatch targets across the NEM in the wake of an intervention.) If intervention pricing was not being implemented, this optimisation process would be expected to result in lower wholesale prices in those regions. However, the use of intervention pricing in connection with system strength directions means that these lower prices are not realised in practice. Instead, intervention pricing serves to keep the wholesale price across the NEM at the level which AEMO, in its reasonable opinion, considers would have been seen by the market had the direction not been issued.

The consultation paper examined the impact of intervention pricing in connection with system strength directions issued in South Australia. During 2018, such directions were in place for around 30 per cent of the time and thus had a sustained impact on wholesale prices. Analysis by the Commission indicates that, during 2018, intervention pricing had a marked impact on wholesale prices in South Australia, as well as marginal impacts on prices in other regions.

The top row of Table 3.1 below shows the average price for the 2018 calendar year using the intervention pricing run of NEMDE which sets the spot price during interventions; the bottom row shows the average price using the dispatch run of NEMDE during interventions. (That is, the amounts shown below account for the fact that intervention pricing occurred in around one third of dispatch intervals in 2018. Taking into account only those intervals when intervention pricing was implemented, the differences between the figures would be substantially greater.) The difference between these two rows gives an indication of the degree to which interventions in South Australia may have affected spot price outcomes in South Australia and other regions.

Table 3.1: Impact of SA directions on spot prices across NEM ($/MWh)

	NSW	QLD	SA	VIC
Average 2018 price using intervention pricing run for interventions	82.1	74.5	100.1	90.0
Average 2018 price using dispatch run for interventions	81.6	73.8	90.1	88.1

Source: AEMC analysis (as at 6 December 2018). Note that these figures include the impact of intervention pricing used in connection with activation of the RERT in January 2018.

As can be seen, the impact on prices is most marked in South Australia. However, even small differences in prices can have significant effects when the volume of energy traded in larger regions is considered.

Across the NEM, the difference between the two prices, multiplied by the volume of energy traded, was $164m (taking into account the impact of the RERT activation in January 2018, which accounted for $104m of the total estimated impact of $267m).[55] For South Australia, the Commission's analysis was that (leaving aside the impact of the January 2018 RERT activation) intervention pricing resulted in wholesale prices that, averaged over the 2018 year, were $71m higher than they would have been had intervention pricing not been applied.

The consultation paper stressed that these figures represent an upper limit of the impact of intervention pricing. This is because the market could be expected to self-correct at least to some degree if intervention pricing was not applied and prices were allowed to fall in response to additional generation coming online in response to a system strength direction. For example, in South Australia, removing intervention pricing and allowing the spot price to fall to reflect the supply demand balance that follows from the direction could be expected to prompt generators to rebid or withdraw from the market rather than pay to generate when prices fall to strongly negative levels.

In addition, the consultation paper acknowledged that higher spot prices typically do not translate immediately or directly into higher prices for consumers. This is because most retailers have hedge contracts with generators in order to manage wholesale price volatility. However, contract prices are negotiated having regard for expectations about future spot prices. Given that the ElectraNet synchronous condensers will not be in place until mid to late

55 AEMC, *Investigation into intervention mechanisms and system strength in the NEM - consultation paper*, April 2019, p. 60.

2020, it is reasonable to expect that directions will continue to be issued in the interim. If intervention pricing continues to apply as it has done to date, then high spot prices in South Australia can be expected to put upward pressure on contract prices and thus wholesale energy costs (which account for around 46 per cent of a typical electricity bill in South Australia).

While some stakeholders stressed that the Commission's analysis represents an upper limit of the impact of intervention pricing (for example, Energy Australia described it as an "absolute upper limit... as the market would self correct to some degree"[56]), others agreed with the Commission's view that higher wholesale prices can impact contract prices and thus prices borne by consumers. Snowy Hydro's submission noted:[57]

> Over time contract offers for hedging in the financial markets are impacted if AEMO intervention becomes a routine feature of the market. .... If intervention becomes a routine feature of the market then it would be contrary to the NEO.

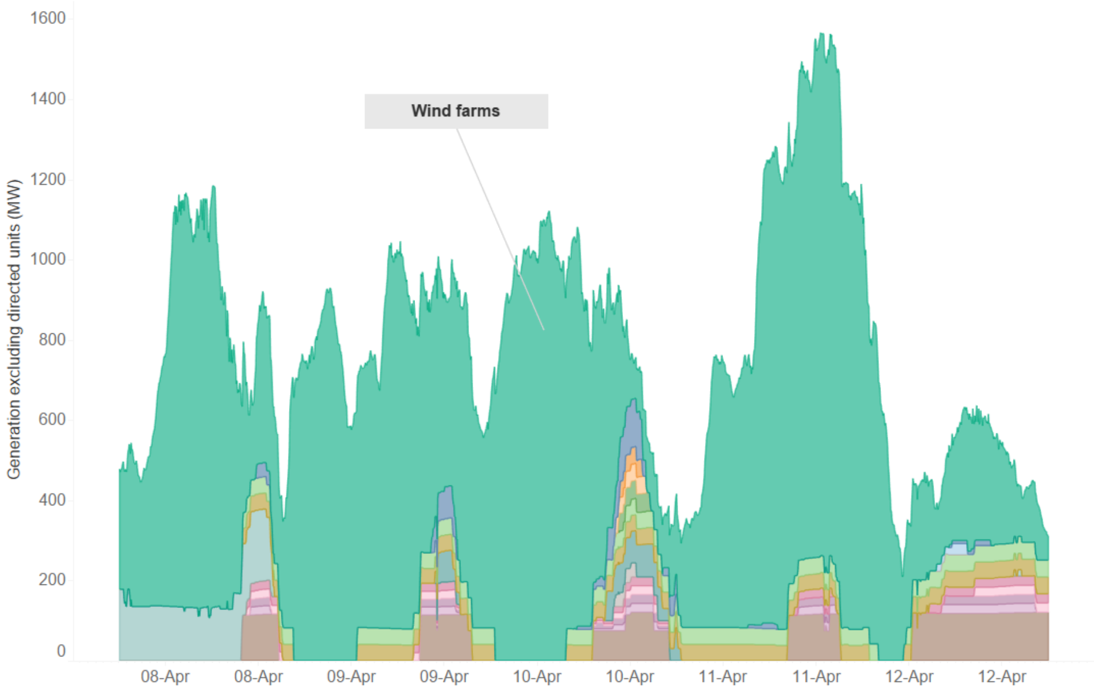
3.2.2 Who receives the intervention price?

The consultation paper noted that the chief recipients of higher spot prices during system strength directions will be wind generators (who do not provide system strength), together with any gas fired generators who are operating without being directed to do so. Gas fired generators who are operating pursuant to a system strength direction do not receive the spot price. Instead, they are compensated based on the 90th percentile price. This highlights the issue of what signals are being sent both to generators in operational timescales, and to potential investors.

Figure 3.2 below shows which generators were online without being directed during a system strength intervention that occurred in April 2018. The green area indicates the output from wind farms while the other units that were online were non-directed gas fired generators. As can be seen, the intervention price was predominantly paid to wind farms rather than non-directed gas fired generators.

56 EnergyAustralia, Submission to consultation paper, p. 2.
57 Snowy Hydro, Submission to the consultation paper, p. 3.

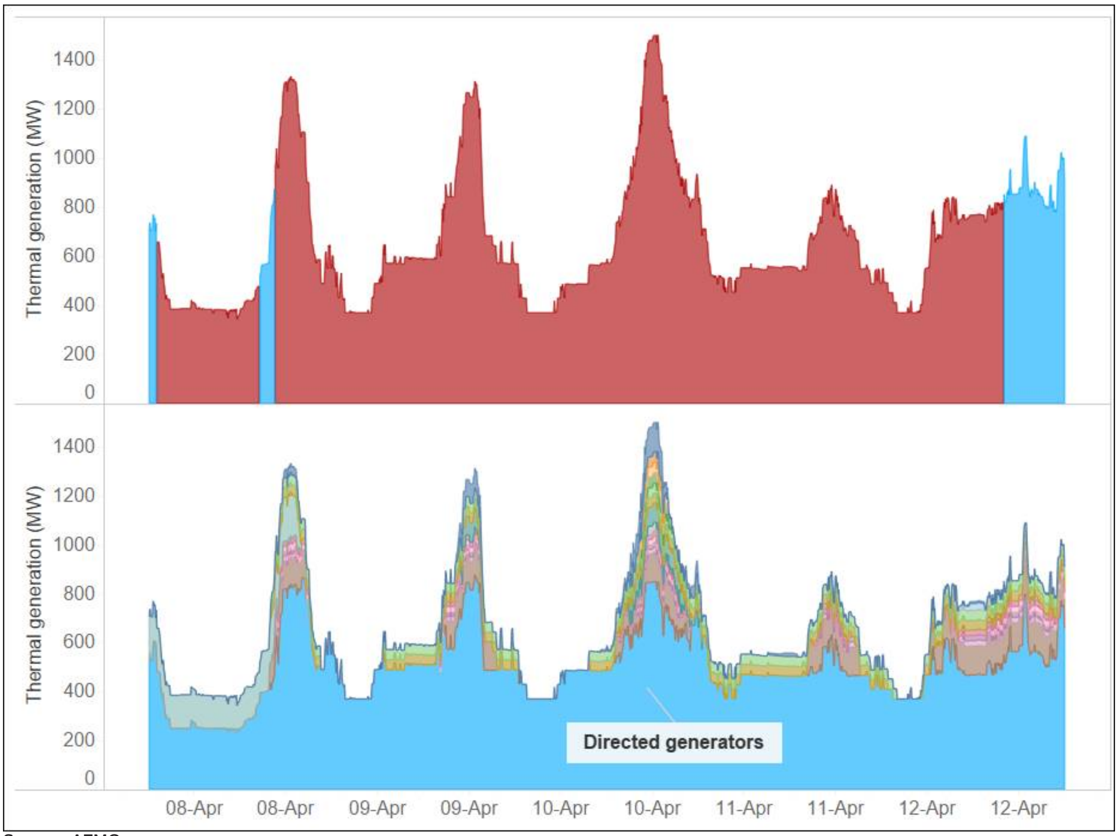
Figure 3.2: Who receives the intervention price during system strength directions?



Source: AEMC

The output of these non-directed gas fired generators was small relative to the output of directed gas fired generators, as shown in Figure 3.3 below.

Figure 3.3: Directed v non-directed gas fired generation during direction



Source: AEMC

The top panel in Figure 3.3 shows total thermal output, coloured according to whether intervention pricing applied (red for intervention, blue for no intervention). The bottom panel shows a breakdown of the different units that were online during the intervention. The directed units (Pelican Point, Torrens A3, A4, B1, B2, B3) are grouped and coloured blue while the non-directed gas fired units are shown in a variety of colours.

For this direction, there were periods in the early morning where only the directed thermal units were online. However, there were also periods in the afternoon where several different thermal units came online in response to rising demand and prices.

In its submission to the consultation paper, ERM Power (ERM) notes that - under the present arrangements - generation portfolios which contain both synchronous and asynchronous generation resources, either directly controlled or via contractual arrangements, benefit from both compensation for direction and higher asynchronous generation output which is paid at the higher intervention price. The additional cost of this is borne by consumers.[58] Origin makes a similar point in its submission, stating "generators in South Australia that do not

58 ERM, Submission to consultation paper, p. 2.

contribute to system strength are receiving compensation payments after directions for security due to the what-if process presenting a higher price than the original dispatch price".[59]

3.2.3 AEMO's review of intervention pricing and the Intervention Pricing Working Group

The application of intervention pricing has resulted in some anomalous and unexpected price outcomes in recent times. One such instance occurred on 9 February 2017, when a direction issued in South Australia resulted in prices in Queensland and NSW reaching the market price cap at a time when such an outcome might not otherwise be expected.[60] The prices produced by the two runs (dispatch run and what-if run) on that occasion were materially different.[61]

This was because a feedback constraint in NEMDE bound incorrectly in the what-if run – resulting in less power flowing north to NSW and Queensland and therefore causing more expensive generators to be notionally dispatched in the what-if run, thereby pushing up prices in that run. (Note that these generators were not actually dispatched.)[62] A similar incident occurred on 13 January 2018 when binding feedback constraint equations limited interconnector flows in the what-if run, resulting in higher prices.[63] AEMO has since consulted on and made changes to the Intervention Pricing Methodology to address these issues.

The February 2017 incident prompted AEMO to initiate a review of whether the current intervention pricing methodology is fit-for-purpose. To this end, it commissioned a report from SW Advisory and Endgame Economics to review the implementation of intervention pricing and make recommendations to address issues arising.[64] It also established the Intervention Pricing Working Group (IPWG) to review the report and consider whether changes should be made.

In reviewing recent intervention events, the consultants noted that:[65]

> In many instances, the services that AEMO has obtained for the power system (e.g. system strength and inertia) are ones for which there is no market. In these circumstances, setting intervention prices in other markets (i.e. for energy and FCAS)

59 Origin, Submission to consultation paper, p. 3. The Commission notes that the compensation to which Origin refers relates to the payment of the intervention price, rather than to affected participant compensation, noting that the definition of "affected participant" does not include semi-scheduled generators.

60 SW Advisory & Endgame Economics, op cit, p. 19.

61 AEMO, NEM Event – Direction to South Australia Generator – 9 February 2017, July 2017, p. 15. While the AEMO report refers to a graph showing intervention prices in NSW and Queensland, the relevant graph is not in fact included. Only intervention price outcomes for Victoria and SA are shown.

62 AEMO Intervention Pricing Working Group, Meeting 2 – 20 December 2017, minutes available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/IPWG/IPWG-F2F--Draft-minutes---20171220.pdf AEMO has identified that this outcome resulted from the mixing of measured values (from SCADA) and what-if values (produced in the previous dispatch interval of the pricing run) in the NEMDE algorithm used for intervention pricing purposes.

63 AEMO Intervention Pricing Working Group, Meeting 3, 15 February 2018, slides available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

64 SW Advisory & Endgame Economics, op cit

65 Ibid, pp. 9-10.

may be unnecessary and even counter-productive.

The report concludes that the economic rationale for intervention pricing (being to preserve the price signal that would have been provided to the market if AEMO had not intervened) does not apply when there is no relevant market and that AEMO should not use intervention pricing in such cases.[66]

The report recommends that the intervention pricing framework be designed to address only those instances where there is scarcity of traded services (i.e. energy and market ancillary services).[67] It notes that the economic rationale for intervention pricing in such cases is sound. The consultants also note the inherent difficulty in the rerun approach and suggest that any new rerun approach will be susceptible to unintended outcomes "because of the noise that is inherently introduced during the exercise".[68]

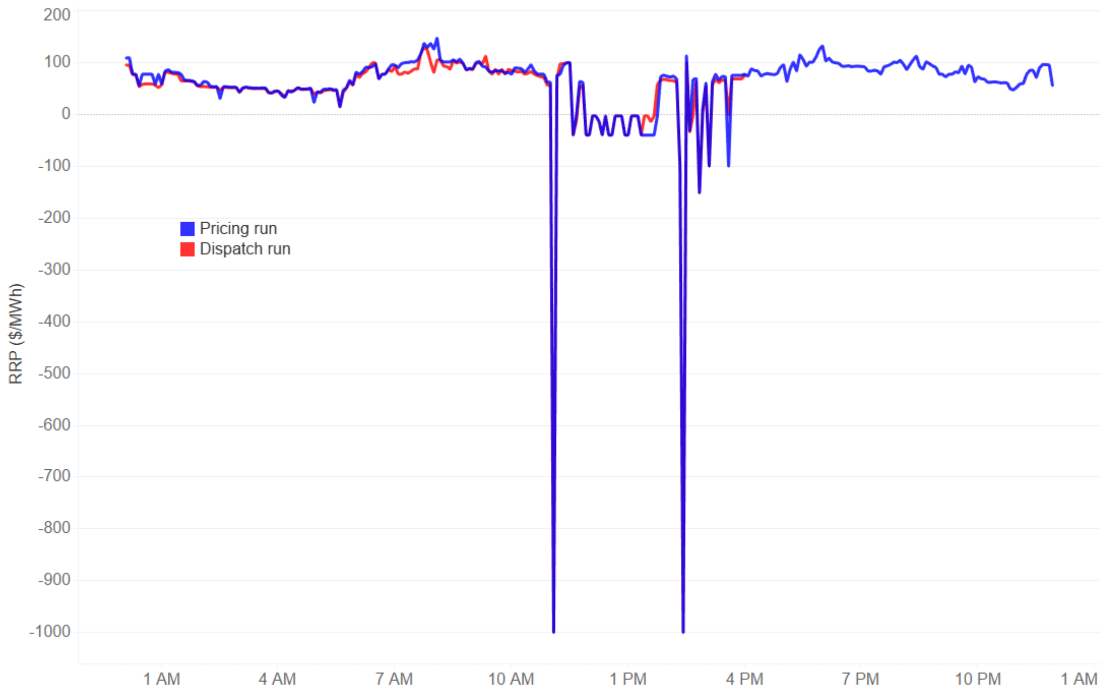
Notwithstanding changes made to the intervention pricing methodology in the wake of AEMO's review, unexpected outcomes continue to arise in connection with intervention pricing. For example, as shown in figure 3.4, prices in the intervention pricing run were lower than in the dispatch run on 1 May 2019, resulting in strongly negative prices in South Australia for several hours. This illustrates the inherent difficulty in estimating prices based on a counterfactual run of NEMDE.

66 Ibid, pp. 28-29.

67 Ibid, p. 49.

68 Ibid, p. 54.

Figure 3.4: Unusual price outcomes resulting from intervention pricing on 1 May 2019



Source: AEMC analysis

The Intervention Pricing Working Group (IPWG) was tasked with considering the recommendations in the SW Advisory & Endgame Economics report, as well as discussing any new approaches that had not been considered.[69]

A number of issues and proposed rule changes were identified.[70] As discussed in section 1.3, two rule changes have already been made in response to requests discussed by the IPWG and submitted by AEMO (these relate to aligning the timetables that govern interventions and settlements, and extending the deadline for the submission of additional compensation claims). Consultation on two further rule change requests commenced as part of this investigation. Two draft determinations were published in conjunction with this report on 15 August 2019. These deal with the RRN test and the compensation threshold that applies to directed and affected participant compensation.

More fundamental changes to the intervention pricing framework were not supported by the IPWG. For example, the IPWG did not support the recommendation by SW Advisory and Endgame Economics that intervention pricing only be used when there is relevant scarcity (i.e. of energy or market ancillary services). The IPWG minutes suggest that the following

69 Terms of reference are available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/IPWG/Intervention-Pricing-WG_Terms-of-Reference_Final.pdf

70 These are detailed in the meeting papers available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group See in particular item 4.1 in the meeting pack for meeting 5.

factors informed the IPWG's view that intervention pricing should continue to be used in connection with system strength directions, even where there is no relevant scarcity.[71]

One participant expressed agreement with the consultant's recommendation that intervention pricing should only be implemented in relation to directions for energy/FCAS scarcity. However, the member considered that "the implications of the recommendations are incorrect. If AEMO could procure system strength services which does not involve provision of energy, then intervention pricing does not need to be implemented. However, if the direction involves provision of energy, intervention pricing needs to be implemented…. Where AEMO undertakes an action that injects extra energy into the market outside of the standard energy market process and this has an effect of changing the energy price at the RRN, then intervention pricing should apply. Others agreed with (this) comment."[72]

Another member disagreed with the consultant's view that there is no economic rationale for intervention pricing during system strength events."The rationale is not to distort the market prices but also not to disadvantage participants in a particular region. If an AEMO direction causes every other generator in the region to pay to generate this is not an optimal outcome."[73]

AEMO staff did note that higher what-if prices signal a need for investment in more generation and this could result in additional investment in wind generation which could worsen the system strength situation.[74] However, the Minutes conclude that "there was a broad consensus that the way intervention pricing is being applied is leading to the outcomes that was intended in the rules and sending the right economic signals, both in investment and dispatch timeframes."[75]

3.2.4 Stakeholder views on intervention pricing

The consultation paper asked: "Is there merit in making more fundamental changes to intervention pricing? For example, should intervention pricing only apply in circumstances where there is scarcity of a market traded commodity? If not, what is the economic rationale for applying intervention pricing?"

Most submissions noted the importance of reducing the frequency of directions and thus the application of intervention pricing. The Commission shares stakeholders' concern in this regard and notes that a separate report on system strength issues will be published later in 2019.

Of the 13 stakeholders who provided comment on intervention pricing:

- five stakeholders supported retaining intervention pricing in its current form (Engie, Powershop, AGL, ERM, EnergyAustralia - EA),

71 IPWG meeting 1 minutes, 20 November 2017, available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group. Page number references in this section relate to these minutes.

72 Ibid, p. 3-5.

73 Ibid, p. 6.

74 Ibid, p. 5.

75 Ibid, p. 7.

- six stakeholders supported applying intervention pricing only when there is an economic rationale for doing so - that is, where the intervention is to obtain a service that is traded in the market (AEMO, TasNetworks, Powerlink, Origin, PIAC and Uniting Communities),
- two stakeholders (Snowy Hydro and AEC) stressed the distortionary impact of intervention pricing but did not express a clear preference for retaining or limiting the use of intervention pricing.

The stakeholders who supported retaining intervention pricing "as is" considered it important to remove market distortion and preserve price signals in cases where intervention results in changes in the level of energy or FCAS provided in the market (regardless of the cause of the intervention). These views are similar to those expressed by the IPWG.

SnowyHydro states that "interventions should only be used as a last resort, (and) when used they must minimise the distortionary effects to the primary NEM spot and contract markets... Intervention can compromise the current market design and its pricing signals affecting wholesale electricity prices and market signals to investors, and the energy and compensation costs faced by consumers".[76]

TasNetworks submits that intervention pricing should only be used when there is a scarcity of traded services (i.e. energy and FCAS) but not for system strength or other system security services for which there is no readily observable price. It considers that modifying the energy price will not appropriately and efficiently signal scarcity of system strength and inertia, and that intervention pricing is imposing costs on consumers and stifling investment signals that would address the issue longer term (as new generation is incentivised to connect regardless of whether doing so will help or hinder system strength).[77]

This view is shared by Powerlink, PIAC, Uniting Communities and AEMO.

Origin expresses a similar view, suggesting that the AEMC should assess the merits of applying intervention pricing during system security interventions where there is no shortfall of a traded commodity such as to warrant preserving market price signals. It also expresses concern that generators which do not contribute to system strength receive additional revenue during system strength directions due to the application of intervention pricing.[78]

AEMO considers it is inefficient to apply intervention pricing during directions whose purpose is to address scarcity of non-market traded services. While intervention pricing is appropriate for supply scarcity directions, AEMO notes that NEM spot prices cannot signal the scarcity of services, such as system strength, which are not market-traded. Therefore, AEMO does not believe it is efficient to preserve the energy or FCAS prices which would have occurred had the system strength direction not been issued. It notes that intervention pricing does not induce the provision of system strength.

Indeed, AEMO notes that intervention pricing during system strength directions may worsen the situation by inducing additional investment in generation capacity which does not aid system strength. Instead, AEMO considers "it is preferable that the energy price reflect the

76 SnowyHydro, Submission to consultation paper, p. 1.

77 TasNetworks, Submission to consultation paper, p, 4.

78 Origin, Submission to consultation paper, p. 2.

level of scarcity of energy on an operational timeframe". (The Commission notes that, in practice, this means allowing the spot price to fall and then self-correct when system strength directions cause additional energy to be injected into the South Australian market.)

This represents an evolution of the view expressed in AEMO's December 2018 position paper that intervention pricing would continue to be implemented in connection with directions for system strength and voltage control if the RRN test is passed.[79]

Stakeholder views on intervention pricing are summarised in the table below.

Table 3.2: **Stakeholder views on intervention pricing**

APPROACH	STAKEHOLDERS
Retain intervention pricing as is	Engie, Powershop, AGL, ERM, EA (5)
Limit intervention pricing to instances where there is scarcity of a market-traded commodity	AEMO, TasNetworks, Powerlink, Origin, PIAC, Uniting Communities (6)

Source: AEMC analysis

3.2.5 Stakeholder views on the regional reference node test

The consultation paper explored two issues relating to the RRN test. First, whether – as AEMO proposed in its rule change request – the test should be extended so that it encompasses the RERT in addition to directions. Secondly, whether the test should be amended so as to limit the circumstances in which intervention pricing should apply.

A number of stakeholders supported the proposal to extend the test to encompass the RERT but made no comment as to whether the test should be amended in the manner proposed by the AEMC (AEC, Powershop, ERM, EnergyAustralia). Others supported the AEMC proposal to change the test in order to narrow the circumstances in which intervention pricing should apply (TasNetworks, Powerlink, Uniting Communities).

As noted above, AEMO supports narrowing the application of intervention pricing to those instances where there is scarcity of a market-traded commodity (an approach that is consistent with the AEMC proposal to change the RRN test).

Stakeholder views on the RRN test are summarised in the table below.

Table 3.3: **Stakeholder views on the regional reference node test**

APPROACH	STAKEHOLDERS
Extend test to apply to RERT	AEC, Powershop, ERM, EA, Origin (5)
Revise test to focus on market-traded commodity	TasNetworks, Powerlink, Uniting Communities (3)

79 AEMO, *Intervention pricing for system security directions - position paper*, December 2018.

Source: AEMC analysis

3.3 Commission's analysis and conclusions

The Commission considers that the use of intervention pricing should be limited to those situations where there is scarcity of a market-traded commodity (at present, energy and FCAS). Where the required service is not market-traded, there is no relevant price signal to preserve and thus no economic rationale for applying intervention pricing. In such cases, the use of intervention pricing can distort price signals rather than reduce distortion. This is contrary to the objective of intervention pricing, being to reduce market distortion arising from intervention events.

The directions issued in South Australia do not respond to a scarcity of energy or FCAS (in which case there would be a clear rationale for implementing intervention pricing). Rather, the SA directions respond to inadequate system strength - a service which, like inertia, is not traded in the market. As described in AEMO's South Australian Electricity report, they are directions for the provision of fault current not for energy.[80]

Intervention pricing was implemented for around one third of hours in 2018, in stark contrast to the use of intervention pricing for reliability directions (of which there have been only two since 2010). During those two events, intervention pricing was used for a total of 4 hours and 5 minutes.[81]

Informed by these sustained higher prices, new entrants may invest in additional capacity, regardless of whether those investments support or undermine system strength.[82] This in turn may result in losses in dynamic efficiency. In this way, efforts to reduce directions-related price impacts on existing generators through intervention pricing can produce inefficient investment signals as well as higher costs to consumers (due to the market clearing at the higher intervention price).

This concern has also been recognised by AEMO which noted in its December 2018 position paper on intervention pricing that:[83]

> There is a broader concern as whether intervention pricing applied in situations where there is no shortage of general generation available (energy or FCAS), distorts price signals seen by potential investors. It is arguable that this goes against what intervention pricing is intended to achieve - that is, avoiding market distortions. However, it is also arguable that the aim of the 2002 code change was to apply what-if pricing as far as possible for any intervention as a consistent arrangement for the use of directions, if they alter market (energy or ancillary service) outcomes.

80 AEMO, *South Australian Electricity Report*, 2018, p. 53.

81 AEMO, *NEM Event – Direction to South Australia Generator – 9 February 2017*, July 2017, p. 12 and AEMO, *NEM Event – Direction to South Australia Generator – 1 March 2017*, January 2018, p. 10.

82 While the "do no harm" framework addresses the location specific impacts on the network of a new connecting generator, it does not address the wider impacts of such connections – in particular, the impact on the merit order and displacement of synchronous generators.

83 AEMO, *Intervention pricing for system security directions - position paper for the NEM*, December 2018, p. 4.

> AEMO considers this to be a policy consideration that is best considered as part of a coordinated review.

The IPWG was of the view that, when a direction results in a perturbation of the supply demand balance, it is appropriate to apply intervention pricing to preserve the price of energy, even though there is no scarcity of energy. (This view was again expressed by a number of stakeholders in submissions to the consultation paper.) On the other hand, the view of the SW Advisory and Endgame Economics was that, if there is no scarcity of a market traded commodity, the use of intervention pricing to preserve signals to the market is not justified.

Indeed, SW Advisory and Endgame Economics considered that the use of intervention pricing in such cases can have the opposite effect to what is intended: it can cause market distortion rather than minimising it, particularly when interventions are in place for a significant proportion of the time. This is because intervention pricing serves to conflate two services - one being generic MW, and one being system strength (in the case of the South Australian directions). By not allowing the spot price to fall when a system strength direction brings additional capacity online, intervention pricing has the effect of holding the price of energy at levels which do not reflect the actual scale and mix of generators providing energy to South Australia.

The consultants' report states:[84]

> In our opinion, there is no economic rationale for altering prices for energy and ancillary service prices during an intervention that occurs to obtain these 'unpriced services'. No amount of modification of the energy price will signal the scarcity of the unpriced services. AEMO should not therefore use intervention pricing in these cases... There is no economic rationale for intervention pricing being applied to energy and FCAS prices - these services were not scarce and so there is no need to confect a price to signal their scarcity.

The Commission shares this view. While it acknowledges that directions for system strength perturb the supply demand balance in South Australia, it does not consider this to be a sufficient basis on which to implement intervention pricing.

Preserving a price signal for energy that does not distinguish between generators which help maintain system strength and those which do not means that market prices are not signalling the services that the system actually needs. Instead, the price for energy creates conditions that are favourable for new entrants, regardless of whether they improve or worsen the situation with respect to system strength. New entrants investing on the back of such prices may exacerbate the existing system strength problem, leading to inefficient outcomes.

While concern about investment signals may not be warranted if intervention pricing was only used for a small proportion of the time, the use of intervention pricing for around one third of dispatch intervals in 2018 means that the impact on average spot prices is significant.

84 SW Advisory, op cit, pp. 28-29.

This distortionary effect is recognised in ElectraNet's February 2019 economic evaluation report which states: "both AEMO and ElectraNet recognise that ongoing use of generator directions beyond the short-term is not a sustainable outcome and leads to distortions in the market, significant costs to consumers and operating difficulties."[85] The impact on contract prices and investment signals was also recognised by Snowy Hydro in its submission to the consultation paper.[86]

Continuing to apply intervention pricing in connection with system strength directions will not deliver the security that the system needs, and may prompt the need for other more costly measures and investments to address resulting system insecurity.

The Commission also notes that, in the case of system security directions such as those being issued in South Australia, intervention prices are a function of a hypothetical generation mix that would never be allowed to be realised in practice. (This is because the intervention pricing run does not include dispatch targets for those generators which have been directed to provide services, thus making the system secure.) AEMO would not allow the system to operate in a state that is insecure as a result of inadequate system strength - as evidenced by the fact that AEMO intervenes in the market by issuing directions when system strength is inadequate.[87] Given this, the Commission does not consider it appropriate to set prices in connection with system security directions based on a counterfactual that is insecure and therefore implausible. In such cases, the intervention price is abstracted to a point that does not reflect AEMO's key obligation to operate the system in a secure state.

The Commission considers it important to mitigate, where possible, dynamic efficiency losses that could accrue if distorted price signals lead to inefficient investment outcomes. It is also vitally important, consistent with the NEO, to mitigate the impact on consumers of higher wholesale electricity prices - as noted in submissions by Snowy Hydro, AEMO, TasNetworks, PIAC and Uniting Communities.

As flagged by ERM Power and Origin in their submissions, the Commission also notes that customers are experiencing higher costs while generator portfolios that include both gas-fired and wind generators are receiving the twin benefits of directed participant compensation and higher prices resulting from the use of intervention pricing (even where the recipients of that higher intervention price do not contribute to system strength). This compounds concern about the inefficiency of the current arrangements and the costs imposed on consumers. Powerlink also notes that renewable generators, in addition to consumers, are the beneficiaries of system strength directions and should therefore contribute to the cost of directed participant compensation: see section 4.2.6.

The Commission also notes that, notwithstanding the changes made by AEMO to its intervention pricing methodology, issues with the application of intervention pricing remain - as illustrated by the price outcomes observed on 1 May 2019. Reducing the risk of such

85 ElectraNet, *Addressing the system strength gap in SA*, February 2019, p. 18.

86 The Snowy Hydro submission noted at p. 3 that "over time contract offers for hedging in the financial markets are impacted if AEMO intervention becomes a routine feature of the market".

87 The situation would be different in the context of a reliability direction: AEMO may allow the system to fall short of the reliability standard so long as it is not insecure.

unintended outcomes is an additional benefit of limiting the use of intervention pricing in circumstances where there is no economic rationale for applying it.

For these reasons, the Commission considers it appropriate to limit the use of intervention pricing to those circumstances where there is a relevant market price signal to preserve: that is, where there is scarcity of a market traded commodity. As with the current RRN test, the Commission considers it appropriate that, where a relevant scarcity (being scarcity of a market traded commodity) is localised and not region-wide, intervention pricing should not apply save for those instances where the relevant localised scarcity coincides with the regional reference node.

While the focus of the consultation paper was on directions issued in response to inadequate system strength, the same rationale applies where directions are issued for other system security services such as voltage control and inertia. The Commission considers that it is not appropriate to implement intervention pricing in connection with interventions to obtain services that are not traded in the market since, in such instances, there is no relevant market signal to preserve. Implementing intervention pricing in such instances can be expected to cause rather than reduce market distortion.

DRAFT DETERMINATION: CHANGING THE REGIONAL REFERENCE NODE TEST TO LIMIT THE USE OF INTERVENTION PRICING

The Commission has determined that the use of intervention pricing should be limited to those circumstances where there is a relevant market price signal to preserve - that is, where there is a scarcity of a market traded commodity. Accordingly, the Commission has published a draft determination which changes the wording of the RRN test to clarify the circumstances in which intervention pricing should apply. The draft determination also extends the reach of the test to encompass the RERT, thereby creating a consistent approach to intervention pricing as between directions and the RERT.

The approach in the draft determination is to apply intervention pricing in the circumstances set out in the table below.

Figure 3.5: When will intervention pricing apply under the revised RRN test?

Service obtained under the intervention	Intervention pricing?
Service for which a dispatch price or ancillary service price is determined (i.e. energy or FCAS)	yes
A service that is a direct substitute for energy or FCAS (e.g. directing a generator to reduce output where insufficient FCAS is available)	yes
Energy or FCAS to address a localised deficiency that coincides with the RRN	yes
Energy or FCAS to address a localised deficiency in a part of the region that does not include the RRN due to a network or other constraint	no
Service for which a dispatch price or ancillary service price is not determined: for example, inertia, voltage control, system strength, non-market ancillary services (i.e. NSCAS and SRAS)	no

Source: AEMC analysis

What are the implications of "turning off" intervention pricing for system strength directions?

In reaching this conclusion, the Commission has had regard for the consequences of changing the RRN test such that intervention pricing no longer applies in circumstances where the purpose of the intervention is to obtain a service that is not a market traded commodity.

The Commission recognises that "turning off" intervention pricing may result in the spot price falling in South Australia during system strength directions such that AEMO needs to issue more directions to gas fired generators.[88] However, the Commission notes that the extent to which this is the case will depend on the degree to which the market self corrects when the spot price falls in response to a direction being issued, and the role of the contract market.[89]

The ability of the market to "self correct" was stressed by stakeholders in response to the consultation paper's analysis of the impact of intervention pricing on wholesale electricity prices. For example, the estimated impact of intervention pricing on wholesale prices was described as an "absolute upper limit" since the market could be expected to self correct in

88 This point was raised by EnergyAustralia in its submission to the consultation paper, p. 2.

89 The consultation paper acknowledged that high spot prices do not immediately and directly translate into higher costs to consumers as most retailers have hedge contracts with generators to manage wholesale price volatility. In the same way that the contract market can mitigate the impact of intervention pricing on consumers, the contract market can also be expected to soften the impact on generators of removing intervention pricing.

the event intervention pricing was not implemented (and the spot price was allowed to fall in response to directed generation coming online).[90]

Consistent with this view, it is not clear to what extent AEMO will need to issue additional directions to gas fired generators to maintain adequate system strength. If, as noted by stakeholders, the market self corrects when intervention pricing is removed, then AEMO may not need to issue additional directions, or may only need to issue a limited number of additional directions.

In any event, the Commission considers that the potential disbenefit of AEMO having to direct more generators for system strength is more than offset by the benefit of sending efficient rather than distorted signals to the market. Any additional costs involved in compensating directed generators should be more than offset by the benefit of the entire NEM clearing at a lower wholesale price. (As discussed in chapter 4, changing the basis on which directed participants are compensated could mitigate the potential impact of AEMO having to direct more gas fired generators for system strength once intervention pricing is "turned off".)

In considering the impact of "turning off" intervention pricing, the Commission also notes that full implementation of the minimum system strength framework will in the near term significantly reduce if not entirely remove the need for AEMO to issue directions to generators to maintain system strength. As such, and all else equal, the system strength framework will significantly reduce or remove the wider impacts on wholesale prices that result from the use of directions and intervention pricing.[91] Accordingly, it is important to keep in perspective any potential concern that removing intervention pricing will result in lower prices, making investment less attractive and thus causing reliability concerns.

In other words, removing the effect of intervention pricing due to system strength directions in South Australia is a question of "when" not "whether". Changing the RRN test and "turning off" intervention pricing in connection with system strength directions simply brings forward the point in time at which the impact of intervention pricing would in any event have been removed (or greatly reduced). Any short term impacts of the proposed new RRN test (e.g. falling prices prompting AEMO to issue more directions) are considered acceptable given the importance of reducing market distortion, sending accurate signals to participants and investors, and reducing upward pressure on wholesale energy prices.

90 EnergyAustralia, Submission to consultation paper, p. 2.

91 Had ElectraNet contracted with generators for the provision of system strength services, intervention pricing would not have been implemented when those generators were called on by AEMO to provide system strength services. Once ElectraNet commissions its synchronous condensers in 2020, the spot price can be expected to fall when wind output is high and demand is low to moderate as AEMO will no longer need to issue system strength directions and implement intervention pricing in connection with those directions. The cost of the synchronous condensers (or generator contracts, had that option been pursued) will be passed through to consumers via TNSP charges, not the spot price.

4 COMPENSATION FRAMEWORK

BOX 2: SUMMARY

The compensation framework ensures that participants who have been directed by AEMO to provide services are not out-of-pocket. This framework also compensates participants affected by an intervention in order to put them in the position that they would have been in had the intervention not occurred.

Directed participant compensation

Currently, generators who are directed to provide energy or FCAS are compensated based on the 90^{th} percentile of spot prices over the preceding 12 months. The consultation paper explored whether the current compensation framework for directed participants is creating inefficient incentives for generators to withdraw from the market if they think they can earn more under direction. During system strength interventions in South Australia, spot prices are typically much lower than the 90^{th} percentile price because these interventions tend to occur during periods of high wind output and low demand.

The Commission considers that there would be merit in adopting a cost based approach to calculating compensation for directed participants. This would avoid the payment of windfall gains to lower cost generators and would ensure that higher cost generators are adequately compensated. A cost based approach will also provide greater predictability and certainty that directed participant costs will continue to be compensated adequately as market conditions and the 90^{th} percentile price change over time.

Recommendation: AEMO to submit a rule change request to change the basis of directed participant compensation to a cost based approach.

Affected participant compensation

Affected participants are those parties whose dispatch targets have been affected as a result of an AEMO intervention event.

Affected participants are entitled to receive from, or pay to, AEMO an amount that puts them in the position they would have been in but for the direction or RERT activation. For example, if AEMO directs a generator online to provide system strength in South Australia and another scheduled generator generates less as a result, it will be paid compensation by AEMO to put it in the position that it would have been in had the intervention event not occurred.

The extensive use of directions for system strength in South Australia raises questions regarding the payment of compensation to affected participants. This in turn raises a more fundamental question as to whether and/or when compensation should be paid to (or by) participants affected by interventions given that generators in the NEM have no right to be dispatched in the wholesale market.

A direction is a way of meeting, or satisfying, a physical constraint on the system, where that constraint is not, or cannot, be represented in NEMDE. If it were possible to implement the system requirements as constraints, AEMO would do so. In that case, there would be no compensation for being constrained down, because generators have no right to be dispatched in the NEM.

The Commission has made a recommendation to align the treatment of participants affected by directions to the treatment of participants affected by constraints under the normal dispatch of the system. In reaching this conclusion, the Commission has also considered that the dispatch targets used to calculate affected participant compensation would never be realised in practice as they constitute an insecure power system. Further, these dispatch targets are able to be influenced by affected participants' bidding strategies so as to optimise the receipt of affected participant compensation. Accordingly, they are not considered a sound basis on which to determine compensation.

Recommendation: AEMO to submit a rule change request to narrow the circumstances in which affected participant compensation is payable to those instances where intervention pricing applies in connection with an intervention event in accordance with the revised regional reference node test.

Transparency and reporting

The Commission considers that there would be benefits from increasing the level of transparency surrounding the quantum of compensation paid to directed and affected participants and improving the timeliness of post-event reporting.

The level of information currently published regarding the cost of compensation is limited and is aggregated to such a degree that there is no visibility as to the share of compensation being paid to directed and affected participants. The quantum of compensation paid is only publicly available where an independent expert report has been prepared and that report identifies the directed or affected participant.

The Commission considers that greater transparency regarding the quantum of compensation paid to individual participants is warranted since this can shed light on any bidding behaviour that may be adopted to maximise the payment of compensation at the expense of consumers. This could be supported by amending the NER requirements for AEMO to publish intervention event reports, requiring more information to be included in reports, and requiring reports to be published in a timely manner.

Recommendation: The AER to submit a rule change request to impose a clear requirement on AEMO to publish its market event reports within a clearly defined period and to require reports to include information regarding the amount of compensation payable to each directed and affected participant.

The Commission also considers that there would be merit in requiring an appropriate level of transparency regarding the payment of compensation to individual participants affected by the activation of the RERT. This would be beneficial as it would shed light on whether the activation of the RERT resulted in affected participant compensation being paid to generators that were turned down in response to the RERT activation. It would also shed light on compliance by AEMO with the proposed cost minimisation principle regarding the choice of intervention mechanisms. The Commission notes that there is currently a gap in the NER in relation to recovering the cost of affected participant compensation following activation of the RERT. The basis for recovery of RERT costs should be clarified through a change to the NER.

Recommendation: AEMO to submit a rule change request to provide a clear basis on which to recover affected participant compensation costs due to a RERT activation and include a requirement in the NER to report on the payment of compensation to individual affected participants following a RERT activation.

The consultation paper examined issues relating to the compensation framework that is triggered when AEMO intervenes in the market by issuing a direction or activating the RERT. In particular, it considered whether this framework has the potential to create incentives for inefficient participant behaviour and impose higher than necessary costs on consumers. These issues are discussed in turn below.

This chapter also discusses an AEMO rule change request which concerns the $5,000 threshold below which compensation is not payable to or by affected participants, and below which additional compensation cannot be claimed by directed participants.

4.1 Background

While intervention pricing is used to set prices in the NEM during an "AEMO intervention event" (encompassing directions and RERT activation but not instructions), there is also a compensation framework to ensure that participants who have been directed by AEMO to provide services are not out-of-pocket.[92] This framework also compensates participants affected by the intervention in order to put them in the position that they would have been in but for the direction or RERT activation. Compensation for affected participants is designed to minimise market distortion resulting from the intervention. It may be paid either by AEMO to affected participants, or by affected participants to AEMO.

Where AEMO issues a direction, compensation is payable to both "directed participants"[93](those parties to whom the direction was issued) and "affected participants"[94] (those parties who are affected by the direction – for example, a generator whose output was reduced to minimise flow on effects from the direction). Where AEMO activates the RERT, compensation is only payable to "affected participants" – reflecting that, in relation to the RERT, there are no "directed participants". Instead, the party providing services under the RERT is compensated pursuant to the relevant contractual arrangements.

Compensation costs in respect of directions are funded by market customers (and thus end consumers), having regard for the relative benefit each region receives as a result of the

92 No compensation is payable when AEMO issues a clause 4.8.9 instruction.

93 Clauses 3.15.7 to 3.15.7B of the NER.

94 Clause 3.12.2(a)(1) of the NER.

direction and the market share of each market customer.[95] For example, the cost of compensation related to system strength directions in South Australia is borne by market customers in South Australia on the basis that the benefit of the directions is confined to that region. By contrast, the NER are silent as to who should pay for any compensation to participants affected by the activation of the RERT.

4.1.1 Compensation for directed participants

"Directed participants" are eligible to receive compensation so that they can recover their costs.[96] The NER definition of directed participants is broad, encompassing Scheduled Generators, Semi-Scheduled Generators, Market Generators, Market Ancillary Service Providers, Scheduled Network Service Providers or Market Customers.

Where the directed participant has provided energy or market ancillary services, compensation is in the first instance paid automatically. AEMO adjusts the settlement process so that directed participants are paid for the energy or market ancillary services they provide pursuant to the direction at the 90th percentile price, calculated by reference to the regional spot price in the preceding 12 months.[97] Where a participant is directed to provide services other than energy and market ancillary services, "fair payment price" compensation is to be calculated by an independent expert in accordance with clause 3.15.7A.[98]

Directed participants can also lodge a claim for additional costs, including loss of revenue, if payment at the 90th percentile price or the fair payment price is not adequate to cover their costs.[99] However, a $5,000 threshold per trading interval applies to claims for additional compensation.[100]

The entitlement of directed participants to receive compensation was included in the NER following a review of directions by NEMMCO and NECA in 2000. That review concluded that directed participants should receive a "fair payment" that would cover the cost incurred by the participant in complying with the direction while minimising inequitable impacts on other market participants.[101] The review noted the "existence of the incentive to withdraw capacity" and that this "supports the case that directed participants should be given a 'fair payment'".[102]

The report concluded that the quantum of compensation paid to directed participants should not be set so high as to incentivise generators to withdraw capacity in order to be directed,

95 Clause 3.15.8 of the NER.

96 Clauses 3.15.7 to 3.15.7B of the NER.

97 Clause 3.15.7(c) of the NER.

98 However, pursuant to clause 3.15.7A(a1), services other than energy or market ancillary services may still be considered for compensation purposes to be services for energy or market ancillary services in certain circumstances: namely, where there would have been no need to direct a participant to provide the service if the participant had bid available to provide energy or market ancillary services. In other words, where services - such as system strength or voltage control - are provided as a by-product of the provision of energy or market ancillary services, they will be dealt with under clause 3.15.7 and compensated based on the 90th percentile price, not compensated based on a fair payment price under clause 3.15.7A.

99 Clause 3.15.7B of the NER.

100 Clauses 3.15.7B(a4) of the NER.

101 NEMMCO and NECA, *Final Report – Power system directions in the National Electricity Market,* 2000, p. i, p.6.

102 ibid, p. 29.

resulting in abnormally high profits.[103] Adopting a principle of setting the payment at a fair price was seen to "offer a degree of comfort to parties concerned about abnormal profits being made out of directions".[104] While the report of the review set out the fair price principle as the basis on which compensation should be calculated, it did not set out the detail of determining compensation based on the 90th percentile price. This was done through a later Code change process. The same review also concluded that affected participants should be compensated so that their financial position is not affected by the direction (as discussed in the next section).

When a market participant is directed to provide services, AEMO retains the trading amount that the participant would have received for the services had the participant voluntarily provided them (meaning that the participant does not receive the intervention price, in cases where intervention pricing has been implemented).[105]

In place of the trading amount, AEMO pays the participant for its energy or market ancillary services at the 90th percentile rate. This feature of the compensation framework helps explain why reliability directions are so rare (there have only been two since 2010). During a reliability event, the spot price is generally high, reflecting a tight supply demand balance. This means that it will be more attractive for generators to participate voluntarily in the market and earn the spot price if it is higher than the 90th percentile price.

However, when spot prices are relatively low (as often occurs in South Australia when wind output is high and demand low), then it may be more attractive for generators to be directed and paid the 90th percentile price rather than receive the spot price. This has important implications for generator bidding behaviour and is discussed further below.

4.1.2 Compensation for affected participants

Affected participants are those parties (being scheduled generators or scheduled network service providers) whose dispatch targets have been affected as a result of an AEMO intervention event. The definition of affected participant in Chapter 10 of the NER also includes "eligible persons", being SRD unit holders who are entitled to receive an amount from AEMO where there has been a change in flow of a directional interconnector.[106]

Affected participants are entitled to receive from, or pay to, AEMO an amount that puts them in the position they would have been in but for the direction or RERT activation.[107] For example, if a generator generates less in the dispatch run than in the intervention pricing run, they will be paid compensation by AEMO to put them in the position that they would have been in had the intervention event not occurred. That is, they will be paid the difference between the amount they have received based on their dispatch targets in the dispatch run

103 ibid, p. 30.

104 ibid, p. 29.

105 See clause 3.15.6(b) of the NER.

106 SRD is shorthand for settlements residue distribution agreements. A SRD unit is defined in chapter 10 of the NER as "a unit that represents a right for an eligible person to receive a portion of the net settlements residue under clause 3.6.5 allocated to a directional interconnector for the period specified in a SRD agreement entered into between that eligible person and AEMO in respect of that right". These units are auctioned off by AEMO as part of the process of managing inter regional settlement residues.

107 Clause 3.12.2(a)(1) of the NER.

(combined with the price from the intervention pricing run), and the amount they would have received based on their dispatch targets in the intervention pricing run (again combined with the price from the intervention pricing run). The amount paid to the participant is net of the short run costs that the generator did not incur as a result of being dispatched less.

By contrast, if a generator's output following an intervention is higher than it would have been had the intervention not occurred (i.e. it generates more in the dispatch run than in the intervention pricing run), it will be liable to pay an amount back to AEMO - being the additional revenue it earned, net of the additional short run costs it incurred.

While such sums can be considerable, no information is publicly available as to the quantum of compensation paid to or by individual affected participants. Only the "compensation recovery amount" is published by AEMO.

This is the sum of the

- compensation paid by AEMO to directed participants (net of the trading amounts retained by AEMO in accordance with clause 3.15.6(b) of the NER)
- compensation paid by AEMO to affected participants net of amounts paid by affected participants to AEMO, and
- costs paid by AEMO to independent experts.

The only exception is where an independent expert has been engaged to assess a claim by an affected participant for additional compensation, or where the affected participant disputes the amount it has to pay to AEMO and this is reviewed by an independent expert.

Affected participants are entitled to receive compensation once a direction has been issued, regardless of whether intervention pricing has been implemented in connection with that direction.

As with directed participants, the compensation process for affected participants is automatic: affected participants need not lodge a claim for compensation. AEMO is required to notify affected participants of the estimated level at which they would have been dispatched had the intervention not occurred, and the trading amount they would have received had the intervention not occurred.[108] This additional amount is then incorporated into the participant's final statement for the relevant billing period.[109] To estimate these figures, AEMO reruns NEMDE, doing both a dispatch run and an intervention pricing run (even if intervention pricing is not being implemented).

At present, no compensation is payable to the affected participant, or payable by that participant to AEMO, if the amount payable is less than $5,000 per trading interval.[110] However, AEMO has lodged a rule change request to change this so that the $5,000 threshold applies per intervention event, rather than per trading interval. This is discussed below in section 4.4 and in the Commission's draft rule determination relating to the threshold for participant compensation following market intervention.

108 Clause 3.12.2(c) of the NER.

109 Clause 3.12.2(d) of the NER.

110 Clause 3.12.2(b) and (i) of the NER.

This threshold also applies to directed participants (but only in respect of claims for additional compensation).[111] The rationale for the threshold is that, if the amount is less than $5,000, this amount is immaterial and does not justify the costs of determining a compensation payment.[112]

4.2 Quantum of directed participant compensation

4.2.1 Issues with the current compensation framework

The consultation paper explored whether the current compensation framework for directed participants is creating inefficient incentives for generators to withdraw from the market if they think they can earn more under direction. It noted that the current use of directions in South Australia raises questions as to whether the compensation framework strikes an optimally efficient balance between, on the one hand, fairly compensating directed participants for their services and, on the other, the level of compensation costs imposed on consumers.

A framework that over-compensates generators may create incentives for generators to bid unavailable and await a direction from AEMO, with flow on effects for costs facing consumers and increased operational complexity for AEMO.

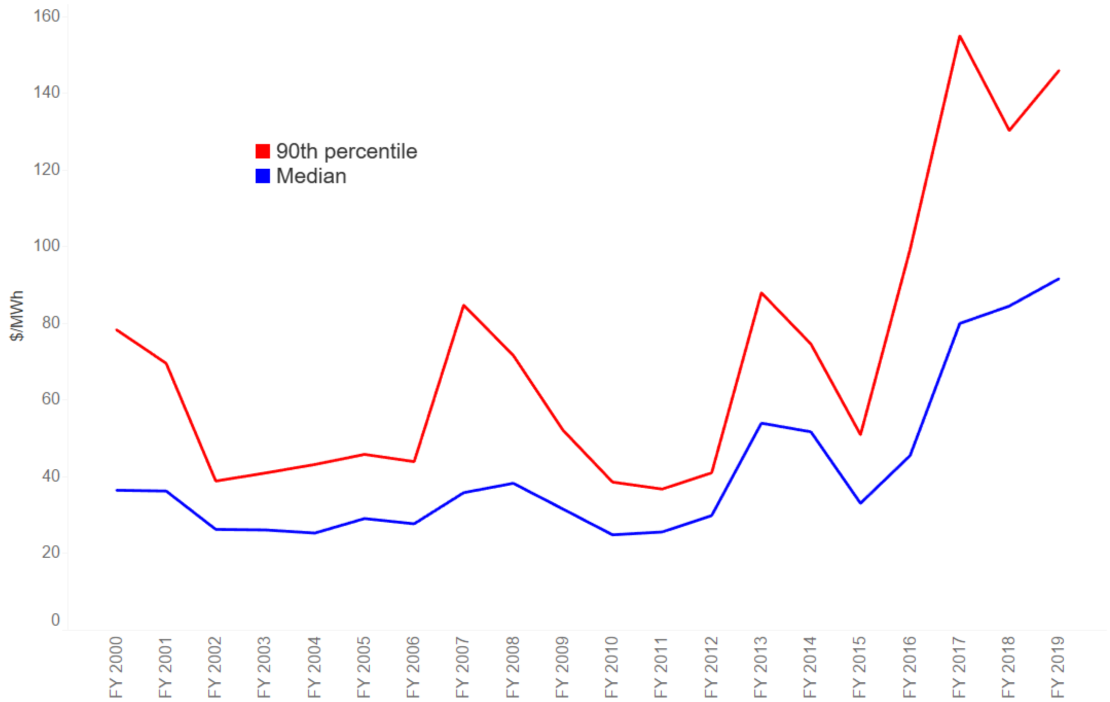
The 90th percentile of prices is relatively high in comparison to the median price. The median is the 50th percentile: that is, the level which prices exceed 50 per cent of the time. It is therefore a good indication of the typical prices seen in the market (whereas the mean will be influenced by high price events). If we look at the spot price at any point in time, it is more likely to be closer to the median than the mean.

Figure 4.1 compares the South Australia median price with the South Australia 90th percentile price on an annual basis from 2000 to 2019. In some years (e.g. 2016), the 90th percentile is more than double the median.

111 Clause 3.15.7B(a4) of the NER.

112 SW Advisory & Endgame Economics, op cit, p. 51

Figure 4.1: Median v 90th percentile price in South Australia



Source: AEMC analysis
Note: 90th percentile prices are calculated on a financial year basis from 1 July 1999 to 30 June 2019. This effectively shows the price that AEMO would apply to determine compensation on 1 July of each year. In practice, AEMO calculates the 90th percentile on a daily basis, and so the 90th percentile price might vary above or below the values shown in this figure.

The 90th percentile price provides a relatively high, and dynamic, level of compensation. The 90th percentile price changes when the distribution of price outcomes changes. Any factor that shifts the whole distribution of prices, or even just the distribution of high prices, will result in a shift in the 90th percentile price.

As can be seen in figure 4.1, the 90th percentile price can vary markedly: for example, moving from a high of $155/MWh in 2016-17 to a recent "low" of $130/MWh in July 2018. The steep rise in the 90th percentile price between 2015 and 2017 reflects the impact of the closure of Northern power station in South Australia followed by Hazelwood in Victoria.

During system strength interventions in South Australia, spot prices are typically much lower than the 90th percentile price because these interventions tend to occur during periods of high wind output and low demand in South Australia. When spot prices in South Australia are low, generators may be incentivised to withdraw their generation and await direction (an issue foreseen by the NEMMCO/NECA directions review discussed earlier).

This has implications for the compensation costs to South Australian consumers, an issue to which AEMO refers in its rule change request relating to the $5,000 compensation threshold. In its rule change request, AEMO states that the proposed change (i.e. making the $5,000 threshold apply per intervention event rather than per trading interval) "strikes a fair balance between the interests of market participants and consumers. If this is a concern, then the appropriate level of compensation at the 90th percentile should be considered for situations where directions are common place."[113]

Another consideration is that system strength is a service that has locational characteristics, meaning that only some generators will be able to help maintain adequate system strength in areas of the grid that have become weak. In more remote areas of the NEM, there may only be a single generator which is able to assist when system strength is inadequate. This creates a market power issue and highlights the importance of ensuring that the compensation framework is fair and does not inefficiently incentivise generators to withdraw and await direction when they are confident their services will be required.[114]

Finally, basing compensation payments on the 90th percentile price is inherently arbitrary. The value of the 90th percentile price is determined by the level of operational demand, the generation mix, generator bidding strategies and, in the case of South Australia, the impact on wholesale prices of intervention pricing. The basis for this pre-determined level of compensation bears no relation to the costs incurred by an individual generator when complying with a direction.

The consultation paper considered whether an alternative approach to directed participant compensation warrants consideration. For example, the compensation methodology created for market suspension events could provide the basis for an alternative approach under which compensation would be a function of the costs incurred by the directed generator, rather than a percentile price reflecting the generation mix in the region at the time.

This approach compensates generators by reference to the short run costs they are deemed to have incurred, together with a premium of 15 per cent.[115] Potential benefits of such an approach are:

- avoiding potential over-compensation to generators which may create an incentive to withdraw their generation and await direction. This would reduce reliance on the labour-intensive directions process and, importantly, reduce compensation costs borne by consumers;
- better accommodating the different costs of various generators since the starting point of the compensation framework is the short run marginal cost (SRMC) of each generator type, rather than a price percentile which is indifferent to individual generator costs; this in turn can avoid under-compensation of more costly generators which necessitates claims for additional compensation;
- making the compensation framework immune to future changes in spot prices as the market transitions: e.g. the increasing penetration of renewables may impact the 90th percentile price, as may the commissioning of synchronous condensers in South Australia.

113 AEMO, *Electricity Rule Change Proposal – Threshold for participant compensation following market intervention*, December 2018, p. 6.

114 It also highlights the importance of ensuring that system strength shortfalls are declared in a timely way, providing sufficient time for efficient solutions to be identified and implemented. This issue will be further explored in a report on system strength to be released later this year.

115 More information about this framework can be found in AEMC, *Participant compensation following market suspension - Rule determination*, 15 November 2018.

Changing the regional reference node test, which determines when intervention pricing applies, is also expected to put downward pressure on prices, as discussed in chapter 3.

4.2.2 Stakeholder views

The consultation paper asked whether the current compensation framework is creating perverse incentives, whether the use of the 90th percentile price is appropriate, and whether a different approach to determining compensation would be preferable.

In response to the consultation paper, Engie and AGL supported retaining the 90th percentile price approach while TasNetworks, Powershop and Uniting Communities supported the cost based approach. AEMO supported lowering the current level of compensation but did not explicitly discuss the cost based approach. Energy Queensland, ERM, EnergyAustralia, TasNetworks and Origin suggested the issue warrants further consideration.[116]

Engie notes that a generator may incur significant costs when asked to start up at short notice, including obtaining fuel at a premium, so 90th percentile price compensation is not too generous and does not incentivise inefficient bidding. It notes that, while the 90th percentile price has an "element of arbitrariness", "the choice of a reference point above the average price is clearly a recognition of the imposition entailed in being required to comply with a direction".[117]

In support of its view that even the 90th percentile price may not be sufficient to cover direct costs, Engie's submission refers to the two claims for additional compensation lodged in relation to system strength directions issued in April 2017. The Commission notes that neither claim involved Engie and AEMO's advice is that these two claims are the only additional compensation claims lodged in relation to system strength directions.

Engie suggests that basing the compensation framework on a cost based approach does not allow peaking plants in particular to recover any of their fixed costs and "creates a moral hazard on the market operator" as "directions will always be cheaper than contractual arrangements that are based on fully absorbed costs or market opportunity costs".

AGL does not agree with the AEMC suggestion that the current compensation framework creates an incentive to withdraw and await direction. It notes that the gap between short run marginal costs (SRMC) and the 90th percentile price is much less now than at market start due to fuel cost increases.[118]

EnergyAustralia notes that it understands that the AEMC may wish to adjust the compensation framework to a more stable price signal (for example an approximate SRMC) but notes that compensation needs to reflect a reasonable level of return and not just simply an approximate SRMC. It notes the impact of directions in terms of fuel costs incurred and maintenance scheduling, and suggests that compensation should not be based simply on an approximate SRMC.[119]

116 All submissions to the consultation paper are available at https://www.aemc.gov.au/market-reviews-advice/investigation-intervention-mechanisms-and-system-strength-nem

117 Engie, Submission to the consultation paper, p. 5.

118 AGL, Submission to consultation paper, p. 4.

119 EnergyAustralia, Submission to consultation paper, p. 3.

ERM notes that, if an alternative approach were to be pursued (such as that outlined in the paper), it would need to include other costs incurred by generators. If not, it would result in increased administrative costs to AEMO and market participants associated with making claims for additional compensation.[120]

Origin expresses concern that, if there are periods of prolonged low wholesale electricity prices, payment at the 90th percentile price will not appropriately value the service provided by the directed generator. It suggests the AEMC should review the approach to ensure that appropriate signals are maintained and that directed participant costs are adequately reimbursed (including fuel and opportunity costs, and physical impacts on generating units).[121]

Powershop considers that the suggested alternative of determining compensation by reference to estimated costs per participant is "likely to lead to a more equitable outcome for consumers and market participants" but notes it has not considered all the potential complexities.[122] It also flags a possible alternative: "the rule could express the compensation as a premium on the market price, establishing different compensation levels for different technologies, or linking the compensation to some calculation based on the average of generator's bids across a time period".[123]

Powerlink considers that, in addition to considering how directed participant compensation should be calculated, the Commission should also consider who should fund the compensation. Powerlink states:[124]

> In many instances it can be readily demonstrated that consumers are the principal beneficiaries of an AEMO intervention, and should therefore fund the cost of the compensation to be paid. However, in the case of intervention for system strength services, Powerlink suggests this reasoning is less compelling.
>
> Directions for system strength provide for the secure operation of the power system and thus benefit consumers. However these directions also allow inverter connected generators to generate when they otherwise wouldn't be able to. Indeed, it is often the case that electricity is exported from South Australia to Victoria when system strength directions are in place in South Australia. As a result, these South Australian based inverter connected generators are beneficiaries of the system strength directions.
>
> Powerlink considers at least part of the compensation costs for system strength directions should be recovered from those inverter connected generators that benefit from being able to generate when they otherwise wouldn't. This would achieve a degree of consistency with the "do no harm" principle set out in the system strength rule changes.

120 ERM, Submission to consultation paper, p. 10.
121 Origin, Submission to consultation paper, p. 3.
122 Powershop, Submission to consultation paper, p. 6.
123 ibid.
124 Powerlink, Submission to consultation paper, p. 4.

AEMO notes that the current compensation framework is resulting in very few claims for additional compensation. Since April 2017, 267 system strength directions have been issued to generators in South Australia (as at 31 July 2019) but only two claims for additional compensation have been lodged in this period. Their submission states:[125]

> This (small number of claims) suggests that this level of 'automatic' compensation is rarely insufficient to cover the costs of directed participants. If compensation payments are consistently greater than directed participant costs, there is merit in lowering the level of these automatic payments. .... AEMO believes that the level of compensation could be set at a lower level while still being sufficient to cover directed participant costs in most cases, noting that participants will retain the right to claim additional compensation if the percentile-based compensation is insufficient.

AEMO also notes that lowering the level of compensation would reduce the impact of removing intervention pricing for system security events (as discussed in chapter 3) because there would be a weaker incentive for online generators to withdraw in response to the lower spot price and await direction. It also notes that the 90th percentile price will decline, especially in South Australia, once intervention pricing ceases to apply (following the commissioning by ElectraNet of synchronous condensers in 2020).

Stakeholder views on directed participant compensation are set out in the table below.

Table 4.1: **Stakeholder views on directed participant compensation**

APPROACH	STAKEHOLDERS
Retain 90th percentile price compensation	Engie, AGL (2)
Consider cost based approach	TasNetworks, Powershop, AEMO, Uniting Communities (4)
Consider the issue further	Energy Queensland, ERM, EA, Origin (4)

Source: AEMC analysis

4.2.3 Commission's analysis and conclusions

In considering whether the current approach to directed participant compensation is optimally efficient, a number of issues arise. These are explored below.

Relationship between 90th percentile price and generator costs

Stakeholders expressed a range of views about the appropriate basis for compensation. While some expressed support for a cost-based approach, others supported the existing approach (based on the 90th percentile price) and some suggested that the 90th percentile price may not be adequate in some circumstances.

For example, Engie noted that the current compensation framework may not appropriately signal the value provided to the system by directed participants. In support of this view it

125 AEMO, Submission to consultation paper, p. 7.

referenced an independent expert report which states: "Clause 3.15.7B does not recognise that peaking gas turbines need to recover their fixed costs over the small number of hours in which they are required to operate, a significant share of which might arise under directions. In these instances, clause 3.15.7B only compensates to a ceiling of avoidable costs. The compensation rules together may immunise directed generators from operating losses but do not obviously compensate the directed generators for the value they provide to the system."[126]

The Commission notes that directions are intended to be a last resort mechanism - consistent with the market design principle set out in clause 3.1.4(a)(1).[127] Until system strength directions in South Australia became frequent, directions had been used very rarely. This is particularly true in relation to directions in response to reliability events: two such directions have been issued since 2010 with a combined duration of four hours and five minutes.[128]

Accordingly, the Commission considers that it would be inappropriate for the compensation framework to be designed so as to allow directed participants to recover their fixed costs, particularly not via the automatic component of the compensation framework. No investor should expect to recover its fixed costs via directions compensation.

Further, a compensation framework that enabled participants to recover their fixed costs would have significant cost implications for consumers. It could also increase the potential for inefficient bidding practices (i.e. generators bidding unavailable with a view to being directed) which could in turn exacerbate cost implications for consumers and increase operational complexity for AEMO.

Similarly, the Commission does not support the approach outlined by Powershop.[129] Linking compensation payable to bids across a given time period is similar to the idea of using the compensation framework to enable participants to recover their fixed costs, since bidding strategies over the course of (say) a year would typically be designed to recover both fixed and operating costs.

For some plant, basing the quantum of compensation on the price at which generators bid available or were dispatched would be particularly problematic - for example, peaking plant that operates very infrequently and only participates in the market when prices are very high. Consider for example a hypothetical generator which only bids available at the market price cap. Its dispatch weighted price would be equal to the market price cap and it would need, under an approach similar to that outlined, to be compensated accordingly if it were directed into service.

Setting compensation by reference to such offers or prices would entail high costs to consumers if such plant needs to be directed into service. Costs to consumers would also be

126 Synergies, *Final report on compensation related to directions that occurred on 1 December 2016,* 2017, p 39.

127 This principle is to minimise AEMO decision-making to allow market participants the greatest amount of freedom to decide how they will operate in the market.

128 These were the directions issued to Pelican Point in February and March 2017.

129 Powershop suggested that consideration could be given to expressing compensation as "a premium on the market price, establishing different compensation levels for different technologies, or linking the compensation to some calculation based on the average of a generator's bids across a time period: see p. 6 of the Powershop submission to the consultation paper.

compounded by the creation of inefficient bidding incentives. (That is, a plant which stood to receive a high level of compensation would have an even stronger incentive to withdraw and await direction, particularly if they were confident that they would be called on to provide services under direction - e.g. due to the locational aspects of system security services such as system strength, or because of a network constraint nearby.) This would be contrary to the principle that intervention mechanisms should be used as a last resort, and would be contrary to the NEO.

While the example noted above is somewhat extreme, it highlights the problem of basing compensation on the value provided to the market by a unit, calculated by reference to offers or dispatch prices. In the case of system security directions, the value of the service provided to the market by the directed generator may be the difference between the "lights staying on" and load shedding in the event a contingency event occurs. The same could also be true of a reliability direction. As such, it could be argued that the value provided to the market by the directed unit should reflect the value of customer reliability, or the market price cap (to which the spot price is set in the event that AEMO instructs a TNSP to shed load).

Clearly, it would not be appropriate to incorporate such values into the directed participant compensation framework since doing so would likely have a hugely distortionary impact on generator bidding behaviour, potentially prompting AEMO to issue more directions and leading to higher costs to consumers. Again this would be contrary to both the NEO and the principle in clause 3.1.4 of the NER that AEMO decision-making should be minimised to allow market participants the greatest amount of commercial freedom to decide how they will operate in the market.

The Commission also notes that, under the current rules, directed participants can lodge a claim for additional compensation under clause 3.15.7B including "loss of revenue and additional net direct costs".[130] This provision sets out the matters that can be considered as part of additional net direct costs, including matters such as incremental maintenance, fuel and staff costs. Such costs are typically characterised as variable operating costs. However, claimable costs also include acceleration of maintenance work and delay costs for maintenance work.[131] In this way, the compensation framework already allows for the recovery of some costs that may be characterised as fixed costs. Importantly, however, such costs are accommodated via the process of making an additional compensation claim - not via the automatically calculated component of the compensation.

The Commission notes that, in certain limited circumstances, the Rules also provide for directed participants to make a claim that, in addition to loss of revenue and additional net direct costs, includes "a reasonable rate of return on the capital employed in the provision of the service".[132] This only applies where AEMO has determined that an independent expert could *not* reasonably be expected to determine a "fair payment price" under clause 3.15.7A within a reasonable period of time. To the Commission's knowledge, this clause has never been used.

130 NER, clause 3.15.7B(a)

131 NER, clause 3.15.7B(a3)

132 NER, clause 3.15.7B(a1)

It is also worth noting that the fair payment price provision only applies when the service provided under direction is a service other than energy or market ancillary services.[133] Based on analysis of publicly available independent expert reports, the fair payment price provision has only been used to compensate directed participants on two occasions (1 December 2016 and 24 January 2019).[134]

In considering what is an appropriate approach to the automatic calculation of compensation for the provision of energy and market ancillary services, the Commission considers that the estimated SRMC incurred by directed participants provides a useful reference point (noting that recipients of automatically calculated compensation always have the option to claim additional costs). Adopting a more targeted cost-based approach has advantages relative to a "one size fits all" approach such as that provided by the 90th percentile price framework.

Such an approach can can help strike an appropriate balance between the interests of generators and consumers - avoiding over-compensation of low cost generators and ensuring that high cost generators do not need to lodge a claim for additional costs every time they are directed. Striking an appropriate balance is important given that the compensation framework is inherently asymmetrical in the sense that generators can claim additional costs but consumers have no ability to recover any over-compensation.

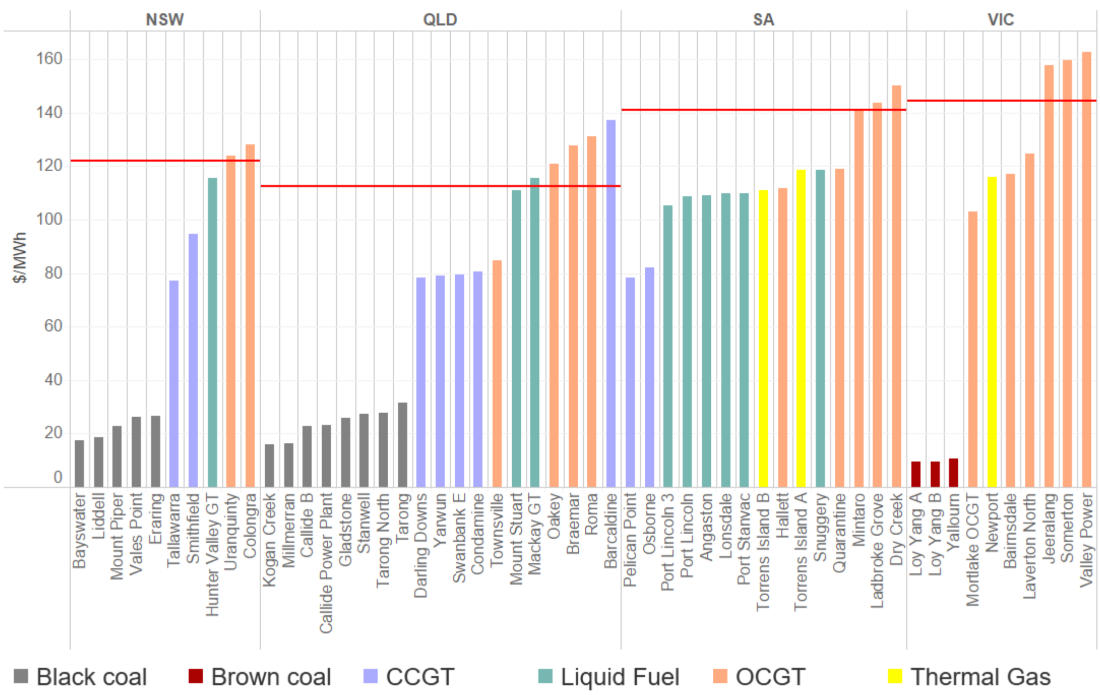
Figure 4.2 below sets out the short run marginal cost (SRMC) of scheduled generators across the national electricity market, calculated using *Integrated System Plan* data for 2019-20.[135] It highlights that, in most regions, there is a sizable gap between the SRMC of most generation capacity and the 90th percentile price (calculated as at end June 2019 based on prices in the preceding 12 months).

133 Pursuant to clause 3.15.7A(a1), as noted earlier, services other than energy or market ancillary services may still be considered for compensation purposes to be services for energy or market ancillary services in certain circumstances: namely, where there would have been no need to direct a participant to provide the service if the participant had bid available to provide energy or market ancillary services. In other words, where services are provided as a by-product of the provision of energy or market ancillary services, they will be dealt with under clause 3.15.7 and compensated based on the 90th percentile price, not compensated based on a fair payment price under clause 3.15.7A.

134 AEMO's market event reports are available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports

135 The calculation of SRMC uses the well recognised formula: SRMC = fuel cost x efficiency [or heat rate] + VOM [variable operation and maintenance costs].

Figure 4.2: Scheduled generator SRMC and 90th percentile price by region



Source: AEMC analysis

Note: SRMC data is sourced from the ISP data inputs for 2019-20. 90th percentile prices are calculated as at end June 2019.

As can be seen, the gap between generator costs and the 90th percentile price is smallest in South Australia, reflecting the current generation mix in that region. In other regions, the gap is larger, particularly in relation to coal-fired plant.

If in future directions are used more frequently in other regions (e.g. to provide system security services), the current compensation framework could result in high costs to consumers that are not proportionate to the costs borne by generators. This is particularly the case where directions are issued to coal-fired plant. This has not been an issue in South Australia, where no coal-fired generating units remain in the market. However, it is possible that AEMO will in future need to direct coal-fired plant in other regions.

Based on ISP analysis of where system strength levels can be expected to fall over time, it is possible that (for example) Mount Piper power station could be directed to support system strength as more asynchronous generation connects to the grid in western NSW. Similarly, Kogan Creek and Milmerran power stations could be directed to support system strength in Queensland as the generation mix transitions there.[136]

136 The Commission has selected these plant for illustrative purposes as they are located near areas where high levels of asynchronous generation capacity is expected to connect over time. They have not been identified based on power system modelling.

These coal-fired power stations have low SRMC relative to the 90th percentile price in their respective regions. Mount Piper's estimated SRMC is $23/MWh while the 90th percentile price in NSW is $122. Kogan Creek and Milmerran have estimated SRMC of $16/MWh while the 90th percentile price in Queensland is $113. In Victoria, brown coal generators have even lower estimated SRMC (around $10/MWh) as compared with a 90th percentile price in Victoria of around $141/MWh.[137]

As such, paying compensation to generators such as these based on the 90th percentile price could result in over-compensation, with adverse cost implications for consumers. The size of the gap between coal plant SRMC and the 90th percentile price is also large enough that it could incentivise inefficient bidding, prompting coal-fired plant to reduce output (or state their intention to do so) and await direction.

Conversely, AEMO may also need to issue system strength directions to plant with high SRMC: for example, Uranquinty (estimated SRMC of $124) in NSW and Mount Stuart ($111) in Queensland. The estimated SRMC of both these plants are just above or just below the current 90th percentile price in their respective regions. Accordingly, compensation based on the current approach may not be adequate to cover the costs of such generators, leading to additional compensation claims and increased administrative costs for both AEMO and market participants.

These illustrative examples serve to highlight the twin challenge in designing an efficient compensation framework for directed participants:

- for high cost generators, the compensation framework needs to be adequate if their SRMC already exceeds, or will in future exceed, the 90th percentile price
- for low cost generators, the compensation framework needs to protect consumers from the cost of compensating generators at levels well above their SRMC.

Impact of the compensation framework on bidding incentives

While Engie and AGL submit that current compensation arrangements do not create inefficient bidding incentives, AEMO's submission acknowledges this dynamic, stating:[138]

> Some participants may view being directed as an alternative to remaining in service and receiving the spot price. A potential consequence of (only applying intervention pricing in response to scarcity of a market-traded service) is an increase in the number of directions required to secure non-market traded services. With lower spot prices during direction, the incentive for synchronous generators which are not being directed to remain in service would be lower, and participant preference for being directed would be stronger. This may result in AEMO needing to direct more synchronous generators than under the current approach to intervention pricing. Lowering the payoff of being directed by lowering the directed participant compensation percentile may reduce the incentive to withdraw and help contain the number of directions.

137 These figures are calculated using ISP data for 2019-20.

138 AEMO, Submission to the consultation paper, pp 7-8.

As discussed in chapter 3 and the Commission's draft rule determination relating to the regional reference node test following activation of the RERT, the Commission has determined that intervention pricing should only apply in a limited range of circumstances: namely, where there is scarcity of a market-traded service such as energy or FCAS (and, where such scarcity affects only part of a region due to a constraint, that part of the region includes the regional reference node). If the final rule is consistent with the draft rule, the spot price during system strength directions in South Australia may be lower than currently. How much lower is impossible to predict since the market can be expected to self-correct by re-bidding when prices fall, a point stressed by stakeholders in response to the consultation paper.[139] Nonetheless, this raises the question of how South Australian gas fired generators might respond to lower spot prices and whether that will result in AEMO needing to issue more directions.

As discussed in chapter 3, analysis undertaken by the Commission indicates that, during interventions, the mix of generators in South Australia is typically dominated by wind farms and relatively few non-directed gas fired generators are operating when system strength directions are issued.

The Commission acknowledges that, all else being equal, removing intervention pricing during system strength directions may mean AEMO needs to direct more gas fired generators to provide adequate system strength. However, the Commission is of the view that the potential cost of AEMO needing to issue additional directions will be offset, or more than offset, by removing upward pressure on wholesale prices, particularly in South Australia but also across the national electricity market, by "turning off" intervention pricing. That is, while additional directions may be needed to a small number of gas fired generators in South Australia, the entire NEM can be expected to settle at lower spot prices than currently.

Given the potential for the removal of intervention pricing to increase the number of directions required, the Commission considers it particularly important to consider whether the current compensation framework will deliver efficient outcomes as market conditions change. As AEMO notes in its submission, lowering the level of compensation payable to directed generators would reduce the potential need for AEMO to issue more directions than currently due to the removal of intervention pricing.[140]

The Commission notes that, to the extent that additional directions are required due to the removal of intervention pricing, any resulting increase in compensation costs would be further offset if other recommended changes are made (for example, to reduce the quantum of directed participant compensation and the payment of affected participant compensation, as discussed in section 4.3).

139 For example, EnergyAustralia stressed that the Commission's analysis of the effect of intervention pricing on wholesale energy prices was an "absolute upper limit" given that the market could be expected to self-correct to some degree in the event that intervention pricing was no longer to apply: Energy Australia, Submission to consultation paper, p. 2.

140 AEMO, Submission to the consultation paper, p. 8.

4.2.4 A new approach to compensating directed participants?

The consultation paper suggested that consideration be given to an alternative approach to calculating compensation for directed participants, similar to that adopted in the market suspension compensation framework.[141] Under that framework, compensation is calculated based on pre-determined "benchmark values" designed to reflect the short run costs that generators are deemed to have incurred. These values are regionally averaged estimated SRMC for generators in each category (black coal, brown coal, open cycle gas turbine, combined cycle gas turbine, hydro, large scale batteries etc). These values are supplemented by a 15 per cent premium to account for divergences between estimated and actual costs.

SRMC are estimated based on data used to model AEMO's Integrated System Plan (and previously the National Transmission Network Development Plan or NTNDP). AEMO already uses this data to calculate the short run costs incurred or avoided by affected participants for the purpose of calculating affected participant compensation pursuant to clause 3.12.2.

The premium in the market suspension compensation methodology was set at 15 per cent in recognition of the static nature of the heat rates included in the NTNDP/ISP inputs and the fact that, in practice, heat rates (and thus fuel costs per unit of energy produced) vary based on factors such as plant loading and ambient temperatures. The premium was also designed to recognise that actual and estimated fuel costs can be expected to vary.

Very little data is publicly available about the heat rates of existing plant when operating at partial loading as such data is commercially sensitive. What data is available indicates that heat rates vary across plant type, age and operating conditions.[142] For existing coal plants, anecdotal evidence suggests that heat rates vary in the order of 15 per cent as between minimum and maximum plant loading.

While some data is available regarding the heat rates of new technologies at different loadings, it serves to highlight that heat rates vary considerably across plant types: heat rates for new coal technologies vary 10-12 per cent between minimum and maximum plant loading, while the variation for new gas plants can be considerably greater.[143]

Such data is of little value in determining the actual heat rates at partial loading of existing plants, which vary considerably in terms of age and technology. Accordingly, setting the premium at an appropriate level is a matter of judgement which must balance the interests of both generators and consumers, as well as striking an appropriate balance between accuracy and transparency/predictability. Adopting a premium of 15 per cent was considered to accommodate reasonable variations between estimated and actual costs, thus limiting the need for generators to claim additional compensation, while at the same time limiting the cost impacts on consumers that a higher premium would entail.

The Commission notes that, while consumers have no right to recoup funds when a generator is over-compensated, a generator may lodge a claim for additional compensation in the event it is under-compensated. As discussed in section 4.4 and the Commission's draft

141 AEMC, *Participant compensation following market suspension - Rule determination*, November 2018.

142 ibid, pp 31-37.

143 GHD, *AEMO costs and technical parameter review, Report Final Rev 4*, September 2018.

rule determination relating to the threshold for participant compensation following market intervention, the Commission has determined to amend clause 3.15.7B so that the $5,000 compensation threshold for directed participant additional compensation claims applies per direction, rather than per trading interval as is currently the case. In this way, any directed participant which needs to claim additional costs will, if the claim is approved by AEMO or an independent expert, be able to recoup its costs in full.

Figure 4.3 below sets out the estimated SRMC of the seven power stations which may be directed by AEMO to ensure adequate system strength in South Australia.[144] It compares these estimated SRMC figures with the 90th percentile price (the range reflects how the 90th percentile price has varied over the 2018-2019 financial year), together with an indication of the compensation that would be payable under a range of different compensation methodologies (i.e. estimated SRMC plus various premia).

Figure 4.3: Estimated short run costs of SA power stations compared with various compensation approaches ($/MWh)

STATION	Tech	SRMC	SRMC +15 %	SRMC +20%	SRMC +25%	SRMC +30 %	90th PERCENTILE
Pelican Point	CCGT	78	90	94	98	102	130-145
Torrens Island A	Thermal Gas	118	136	142	148	154	130-145
Torrens Island B	Thermal Gas	111	128	133	139	144	130-145
Osborne	CCGT	82	95	99	103	107	130-145
Quarantine	OCGT	119	137	143	149	155	130-145
Mintaro	OCGT	141	162	169	177	184	130-145
Dry Creek	OCGT	150	173	180	188	195	130-145

Source: AEMC analysis based on ISP SRMC data for 2019-20.

When AEMO calculates compensation for directed participants under clause 3.15.7 of the NER, the value of the 90th percentile price is determined based on the 12 months immediately preceding the trading day on which the direction was issued.[145] As such, the value of the compensation paid (on a per MWh basis) can change daily. The 90th percentile price column above sets out a range as including a single figure would be misleading. For example, on 1 July 2018, the 90th percentile price was $130, on 1 January 2019 it was $135 and on 1 July 2019 it was $145.

As can be seen, the SMRC + 15 per cent approach delivers a figure which, for Torrens Island A and Quarantine, is in the mid point of the 90th percentile price range. For Torrens Island B, the figure is just below the 90th percentile price range for 2018-19. For Pelican Point and Osborne, the SRMC + 15 per cent figure is well below the 90th percentile range while for Mintaro and Dry Creek, the figure is well above the current 90th percentile range. Adopting a

144 AEMO, *Transfer limit advice - South Australia system strength*, December 2018.

145 NER, clause 3.15.7(c).

higher premium would for most plants result in a substantial increase in compensation payable relative to the current approach. This would be hard to justify based on the costs incurred by generators and the implications for consumers.

Torrens Island A, Torrens Island B, Pelican Point and Osborne appear to be the power stations most frequently directed to provide system strength. This is consistent with the obligation on AEMO to use its reasonable endeavours to minimise the cost associated with directions.[146]

As noted previously, there have only been two claims submitted by directed participants in South Australia since system strength directions began. One claim related to Hallett Power Station which is not a power station listed in the current generator combinations in the South Australian Transfer Limit Advice and has only been directed to provide system strength services on one occasion. The other was submitted in relation to Torrens Island B. Since those claims were submitted in April 2017, no further additional compensation claims have been submitted by participants directed to provide system strength in South Australia (as at late June 2019). Directed participants may also be receiving affected participant compensation which would mitigate the impact of any losses that might be incurred in the course of providing services under direction (see further discussion in section 4.3).

It is possible that, if directions in South Australia were less frequent, there may be more claims for additional compensation. However, the high proportion of time that directions have been in place (30 per cent on average in 2018) means that directed generators are receiving the 90th percentile price for a significant proportion of the year. This may help explain the very small number of additional compensation claims made by directed generators. For example, if a generator incurred costs in connection with a given direction that were not covered by the compensation for that event, it may choose not to lodge a claim if it is confident that it will be directed again (and thus able to make up any revenue shortfall via 90th percentile compensation payments over the period until synchronous condensers are commissioned).

The Commission considers that a compensation framework should be effective, efficient and equitable regardless of how often directions are issued. However, the situation in South Australia (where directions are likely to be in place for a considerable proportion of the time until ElectraNet's synchronous condensers are commissioned in mid to late 2020) is a relevant factor in considering any changes to the current compensation framework.

It may also be the case that directed generators are not lodging claims to recover (for example) start costs (as did Hallett Power Station in April 2017[147]) as they often stay in the market (post direction) when spot prices rise. This means that AEMO must cancel the direction as it is no longer required, consistent with clause 4.8.9.(b)(2). In such circumstances, being compensated under the directions framework at the 90th percentile price may enable the directed generator to recoup its start costs and then proceed to participate profitably in the market when spot prices rise. This is relevant in considering

146 NER clause 4.8.9(b)(1)

147 Synergies, *Final report on claims for additional compensation arising from directions on 25 April 2017*, September 2017.

whether any amended compensation framework should include start costs, as discussed further below in section 4.2.5.

It is possible that amending the compensation framework to adopt a cost based approach could result in more claims for additional compensation. However, this is by no means certain based on experience to date. Consider for example the compensation paid to Torrens Island A based on the 90^{th} percentile price ($130-$145 during 2018-19) compared with its estimated SRMC together with a 15 per cent premium ($136/MWh). Changing the basis of the compensation framework would, in the case of Torrens Island A, appear to have no material effect. However, if in future the 90^{th} percentile price falls, Torrens Island A may be more favourably compensated under the cost based approach compared with the percentile price approach.

For Pelican Point, the compensation payable under the cost based approach would be lower than under the current percentile price approach: $90 v $130-$145/MWh. If the basis of compensation were to change from the current percentile price to a cost based approach, this could prompt Pelican Point to submit additional compensation claims for the first time in relation to system strength directions. However, if Torrens Island A is no worse off under a cost based approach, this may suggest that Pelican Point may also be no worse off under such an approach (having regard for actual costs incurred) and that the quantum of compensation it has actually received entails some degree of over-compensation.

The Commission recognises that a premium of 15 per cent applied to a lower estimated SRMC will give a lower adjusted SRMC. However, the difference in the value of the adjustment is not significant as between the two plants (used here for illustrative purposes): for Pelican Point, the difference between its estimated SRMC and the adjusted value including the 15 per cent premium is $12 ($78 v $90/MWh); for Torrens Island A, the difference is $18 ($118 v $136/MWh).

The Commission has also considered how the current compensation framework would operate if directions were to be used more frequently in regions other than South Australia. To be clear, the Commission is not proposing that directions should be used as a means to manage system security on a regular basis. Indeed, the Commission is examining the system strength framework with a view to optimising its flexible and timely implementation in regions other than South Australia as and when system strength issues arise. Nonetheless, it is relevant to consider how the current compensation framework might operate in other regions, and whether the resulting incentives for generators are efficient.

The table below shows a selection of baseload and peaking plant in Victoria, NSW and Queensland. It compares their estimated SRMC (calculated in accordance with ISP data for 2019-20) and compares this with the 90^{th} percentile price in each region as at end June 2019. As can be seen, the gap between the SRMC of coal plant and the 90^{th} percentile price is large, while for peaking plants the gap is small or non-existent. Again, this highlights the difficulty of applying a one size fits all compensation framework to a range of different generator types.

The Commission acknowledges that estimated and actual costs can differ, for example in relation to assumptions around coal costs. However, a solution to this is for stakeholders to provide their views to AEMO when it consults annually on the ISP data inputs. This could have the dual benefit of making the compensation framework and the assumptions used for planning purposes more robust.

Figure 4.4: Estimated SRMC of plant in NSW , Queensland and Victoria compared with various compensation approaches ($/MWh)

	STATION	Tech	SRMC	SRMC +15 %	SRMC +20%	SRMC +25%	SRMC +30 %	90th percentile
NSW	Mount Piper	Black Coal	23	26	27	29	30	122
	Uranquinty	OCGT	124	143	149	155	161	122
QLD	Kogan Creek	Black Coal	16	18	19	20	21	113
	Millmerran	Black Coal	16	19	19	20	21	113
	Mount Stuart	OCGT	111	128	133	139	144	113
VIC	Yallourn	Brown Coal	11	12	13	13	14	141
	Newport	Thermal Steam	116	133	139	145	151	141

Source: AEMC analysis based on ISP SRMC data for 2019-20. 90th percentile prices are calculated as at end June 2019.

4.2.5 Start costs

ERM's submission notes that, if an alternative compensation approach is to be pursued (such as applies for market suspension events), it would need to include other costs incurred by generators. If not, it would result in increased administrative costs to AEMO and market participants associated with making claims for additional compensation.

While ERM did not refer explicitly in its submission to what additional costs should be addressed by the compensation framework, it has raised the inclusion of start costs in previous submissions to the AEMC's market suspension compensation determination.[148] In its submission to the related AEMO market suspension compensation methodology consultation, ERM suggested that the automatic calculation of compensation should include start costs as set out in the GHD 2018-19 *Costs and Technical Parameters Workbook* published by AEMO.[149]

This GHD data set includes costs per MW for cold, warm and hot starts. As such it takes a different approach to that used by directed participants and independent experts in calculating start costs claimed as part of additional compensation claims. Start costs calculated in accordance with the GHD data vary considerably from the start costs that have been allowed by independent experts (with costs allowed by independent experts being considerably higher).

As discussed in the final determination for the market suspension compensation methodology, there is a range of different approaches for calculating start costs, including the

148 See ERM submission to the draft determination, available at https://www.aemc.gov.au/sites/default/files/2018-10/ERM%20Power.pdf

149 See ERM submission available at https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Market-Suspension-Compensation-Methodology-consultation?Convenor=AEMO%20NEM

long run marginal cost (LRMC) approach, average cost method, discounted average cost method, and single cycle method.[150] The latter was used by both Harding Katz and Synergies in determining additional compensation claims by Origin, Hallett and Torrens Island.[151] The independent expert report for the Hallett and Torrens Island claims highlights the variability in start costs for different plant.[152]

Having regard for the comparison in figure 4.3 of a compensation framework based on SRMC + 15 per cent and the 90th percentile price range, it is evident that the inclusion of start costs would result in more compensation being paid than currently - including to Torrens Island A, Quarantine, Mintaro and Dry Creek which have the highest estimated SRMC of the generation units included in the system strength unit combinations. This would seem contrary to the NEO and unnecessary given that, aside from the two claims lodged in relation to directions issued in April 2017, there have been no further claims for additional compensation in respect of system strength directions.

This leaves open the possibility that, if the compensation framework were to change to a cost based approach, additional compensation claims could be lodged by those plants with lower estimated SRMC (Pelican Point and Osborne and, to a lesser extent, Torrens Island B). However, under changes outlined in section 4.4 below and the Commission's draft rule determination relating to the threshold for participant compensation following market intervention, the Commission has determined to amend the $5,000 compensation threshold which currently applies to directed participant additional compensation claims on a per trading interval basis and instead apply the threshold on a "per direction" basis. This will mean that directed participants who lodge claims for additional compensation will, if the claim exceeds the $5,000 threshold and is accepted, be able to recover their costs in full.

Another consideration is that, when plants are directed online to provide system strength services, they often remain on line once the direction has been cancelled and participate in the market voluntarily when spot prices rise. (Under the national electricity rules, AEMO is required to revoke a direction as soon as it is no longer required.[153]) When spot prices are projected to rise, generators often indicate to AEMO that the direction is no longer required (hence AEMO is required to cancel it) as they wish to participate in the market and receive higher spot prices.

An example of this is set out below. Figure 4.5 shows a period in June 2018 during which three directions were issued to Torrens Island A Unit 1. During this period, the unit remained in service at all times. Directions were issued by AEMO and then cancelled as spot prices fell and then rose again.

150 AEMC, *Participant compensation following market suspension, Rule Determination*, 15 November 2018, section 4.2.3.

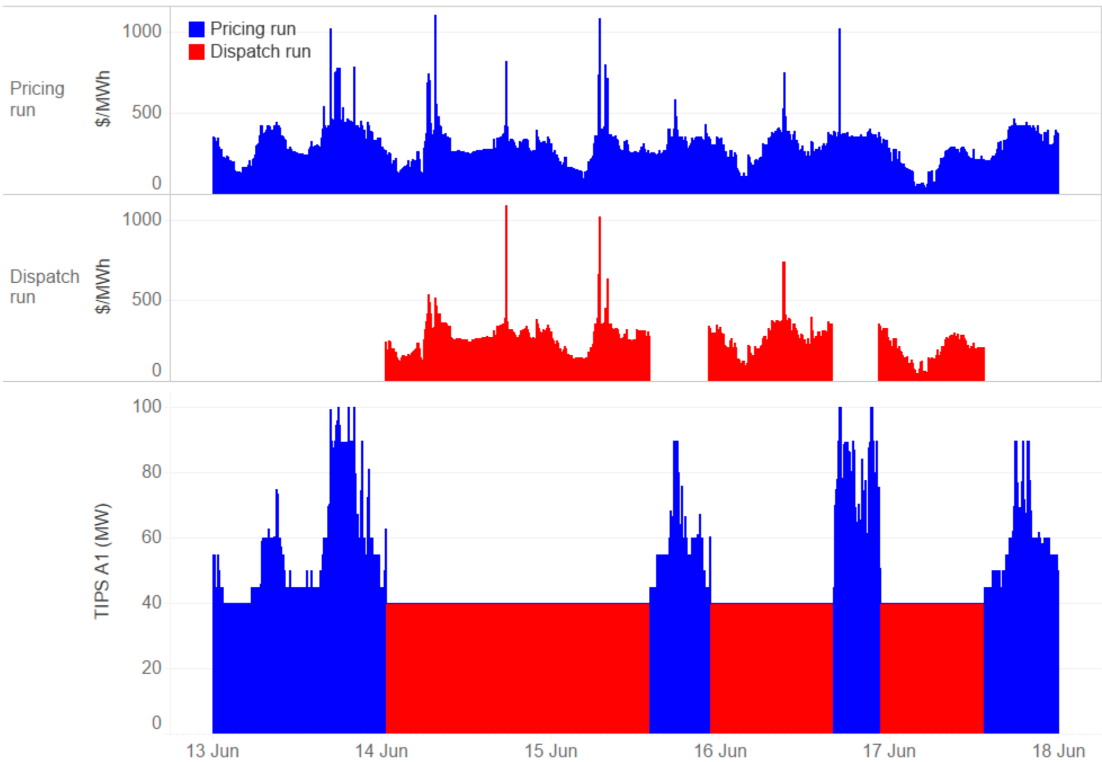
151 Harding Katz, *Compensation for directions in Queensland on 28 and 29 March 2017,* July 2017 and Synergies, *Final report on claims for additional compensation arising from* directions on 25 April 2017, September 2017.

152 Hallett received $2,000 in start costs for each unit that was directed on (to around 2MW each). By contrast, a single Torrens Island unit (B3) was directed on to around 60MW and received start costs of $1,390. As can be seen, the much larger Torrens unit had a relatively small start cost which reflects the significant difference in the technology at each plant. See Synergies, *Final report on claims for additional compensation arising from directions on 25 April 2017,* September 2017.

153 NER, clause 4.8.9(b)(2).

The top panel below shows the spot price (including as set by the intervention pricing run when directions were in place) while the second panel shows the prices in the dispatch run when directions were in place. (It is interesting to note that prices in the dispatch run exceeded those in the intervention pricing run late in the day on 14 June.) The bottom panel shows in red the periods when the unit was operating subject to direction at "min gen" (broadly, minimum safe operating level). The blue areas indicate the periods when directions were not in place and the output of the unit increased above min gen. As can be seen, the periods when directions were in place generally coincide with periods when the spot price was low. Directions were cancelled (and unit output increased) in anticipation of periods when spot prices were higher.

Figure 4.5: Interventions issued in June 2018 - implications for payment of start costs



Source: AEMC analysis
Note: Bottom panel shows the operation of TIPSA1 under direction (red) and without direction (blue).

Such generator behaviour represents rational generator behaviour. However, if participants were to receive start costs as part of their automatically calculated compensation, this could increase the incentive to withdraw from the market when prices are low and await direction, or change their behaviour once a direction has been issued.

In circumstances where such generators remain in the market following the revocation of a direction, they will (if starts costs are automatically compensated) have been compensated for costs that they would have incurred in any case had they decided to enter the market voluntarily in response to rising spot prices. To the extent that the automatic payment of start costs changes their bidding strategy, this may produce inefficient outcomes, for example if it results in the displacement of lower cost generators.[154] The example above illustrates that it would not be efficient to compensate TIPSA1 for its start costs in connection with the three directions issued.

One approach to address this could be to include automatic compensation for start costs in the event that a generator is not operating at the time a direction is issued and the generator later desynchronises, rather than remaining in the market, when the direction is cancelled. However, and again having regard for the comparison of compensation approaches in figure 4.3, it is not evident that including start costs is necessary in order to provide generators with adequate funds to cover their costs. In addition, providing automatic compensation for start costs only in these limited circumstances (so as to remove the potential for windfall gains) would create operational complexity since AEMO has an obligation to minimise the costs associated with directions[155] and it will not be possible for AEMO to determine ahead of time whether a directed participant will or will not remain in the market once the direction has been cancelled (meaning AEMO would not know in advance whether the participant would be eligible to receive automatically calculated start costs). This would increase the difficulty for AEMO of complying with the cost minimisation obligation in clause 4.8.9.

The two additional compensation claims lodged to date in relation to system strength directions illustrate the challenge in designing an efficient compensation framework with respect to start costs. The first claim related to a direction issued to Hallett power station. It synchronised eight units in response to the direction and desynchronised when the direction was cancelled just under 12 hours later. It claimed $16,000 in start costs, being $2,000 for each 2 MW unit, representing maintenance costs "brought forward by the direction". It also claimed additional compensation to cover fuel costs. As a result, Hallett was paid additional compensation amounting to just under $90,000 (in addition to the $26,000 of compensation automatically determined based on the 90th percentile price).[156]

A direction was also issued to Torrens Island unit B3. It was directed to synchronise and follow dispatch targets from 7.45am on 25 April until the direction was cancelled just after noon on 26 April. Automatically determined compensation based on the 90th percentile price was calculated at $203,000. A claim for additional compensation was also made in relation to this direction, including to recover start costs of $16,000.[157] Ultimately, additional compensation of $12,000 was paid.[158] Following cancellation of the direction, the Torrens unit remained in operation for several hours.

154 For example, if a generator is directed to come online to provide system strength and the generator's start costs are automatically compensated and recovered from consumers, the generator may subsequently - once the direction is cancelled - bid available at a lower price than would otherwise be the case since the generator's bidding strategy does not need to recover start costs.

155 NER, clause 4.8.9(b)(1)

156 Synergies, *Final report on claims for additional compensation arising from directions on 25 April 2017,* September 2017.

157 ibid, p. 11.

158 It is noted that, in both cases (Hallett and Torrens), the independent expert chose to apply the $5,000 compensation threshold on a per event basis, rather than on a per trading interval basis. Had the latter approach been adopted, the amount of compensation payable would likely have been less, particularly in relation to fuel costs claimed.

While full analysis of system strength directions has not been undertaken, the Commission understands – based on partial analysis of some key directed generators – that, more often than not, generators will indicate their intention to re-enter the market once prices rise, prompting AEMO to cancel the direction on the basis that it is no longer required in accordance with clause 4.8.9(b)(2). It is far less common for a generator to desynchronise when AEMO revokes the direction. This is relevant in considering whether it is appropriate to include start costs in the compensation framework.

4.2.6 Who should fund compensation?

As noted by Powerlink, consumers are not the sole beneficiaries of system strength directions issued to gas fired generators in South Australia. While consumers benefit from the system being made secure, beneficiaries also include those asynchronous generators which are able to operate and earn revenue rather than being constrained down due to inadequate system strength.

One way in which such participants could contribute to the cost of directed participant compensation would be for them to be included in the definition of "affected participant" (which is currently limited to scheduled generators, scheduled network service providers and SRD unit holders). A proposal to widen the definition of affected participant in this way was put before the Intervention Pricing Working Group by AEMO but has not been progressed. In particular, the suggestion was that semi-scheduled generation be "included in the definition of affected participants for potential compensation when the semi-schedule dispatch cap applies differently between the outturn and pricing runs".[159]

It is possible that, if such a change were made, asynchronous generators might be liable to repay revenue to AEMO more often than they receive compensation from AEMO on the basis that, during system strength interventions, they were able to be dispatched more in the dispatch run (with directed generators online) than in the intervention pricing run (which excludes the directed generators).

Such payments, which are designed to put the affected participant in the position that they would have been in but for the intervention, would reduce the amount of the "compensation recovery amount" (CRA) that is recovered from market customers.[160] As such, this change would - if no other changes were made - address the issue raised by Powerlink in its submission about who should fund directed participant compensation.

However, the Commission recommends that a range of changes be made: notably, that eligibility for affected participant compensation should be narrowed so that it is only available in respect of interventions which trigger intervention pricing (see section 4.3.4). The Commission has also determined that intervention pricing should not be triggered in connection with system security directions (see section 3.3).

159 See rule change proposal number 6 in the meeting pack for IPWG meeting 5, document 4.1, available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

160 The CRA is the top up amount that is required (in addition to the trading amounts retained by AEMO when it directs a generator) to cover the cost of compensating directed participants and the net cost of compensating affected participants.

If both changes are implemented, the end result would be that affected participant compensation would not be payable in connection with system security interventions. Accordingly, the merit of widening the definition of "affected participant" is largely moot since the circumstances when affected participant compensation would be payable in future are expected to be limited. (Only two reliability directions have been issued since 2010, compared with 267 system strength directions since April 2017).

A related issue is that "turning off" intervention pricing for system security interventions via changes to the regional reference node test will, together with the recommendation to remove counteractions (section 5.3.3), have the effect in many instances of allowing spot prices across the NEM to fall to some degree. This is due to additional output from directed generators in South Australia displacing marginal generating units in other parts of the NEM.[161] The result, which is currently masked by the use of intervention pricing, would be lower spot prices in regions where output from the marginal generator/s is reduced or displaced by energy paid for by South Australian consumers via directed participant compensation.

As such, market customers in regions other than South Australia may be said to benefit from the system strength directions issued to South Australian generators. Accordingly, it may be appropriate for them to contribute some share of the cost of compensating directed generators. AEMO could give consideration to this as part of its application of the regional benefit test in clause 3.15.8(b1).[162]

4.2.7 Recommendation

In light of the above analysis, the Commission concludes that there would be merit in adopting a cost based approach to calculating compensation for directed participants. This would avoid the payment of windfall gains to lower cost generators and would ensure that higher cost generators are adequately compensated in the event AEMO determines it must direct these higher cost generators (noting that AEMO is obliged to use its reasonable endeavours to minimise costs related to directions).

The Commission considers that the approach adopted in the market suspension compensation methodology has merit as it takes as its starting point the costs incurred by the directed generator, rather than a percentile price that is determined by exogenous factors. Adopting a cost based approach will provide greater predictability and certainty that directed participant costs will continue to be compensated adequately as market conditions and the 90th percentile price change over time.

In the case of South Australia, a relevant consideration is the Commission's draft determination that intervention pricing should no longer apply in relation to system strength directions (and other directions to obtain security services not traded in the market). If the final rule is consistent with the draft rule , this change will have implications for spot prices,

161 The extent to which prices might fall is not knowable in advance since it will depend on the degree to which the market self corrects.

162 That clause provides: AEMO must, as soon as practicable following the issuance of a direction, determine the relative benefit each region received from the issuance of a direction in accordance with the regional benefit directions procedures.

particularly in South Australia, and may impact the 90th percentile price used to determine compensation for SA directed participants.

As AEMO notes in its submission, this impact on SA spot prices may result in AEMO having to issue more directions to gas fired generators as "the incentive for synchronous generators which are not being directed to remain in service would be lower, and participant preference for being directed would be stronger".[163] Changing the basis of the compensation framework to reflect the estimated costs incurred by directed generators could mitigate this effect, thereby reducing operational complexity for AEMO (by reducing the number of directions it needs to issue) and compensation costs to consumers.[164]

The Commission does not support the inclusion of start costs based on analysis to date, however such issues could be further examined in the event that a rule change is submitted to change the basis on which directed participant compensation is calculated.

While no change to the Rules is required, the Commission encourages AEMO to consider whether it would be feasible to identify regions (other than the region where the direction was issued) that benefited from system strength directions currently paid for by consumers in only one region.

> **RECOMMENDATION 2:** CHANGING THE BASIS OF DIRECTED PARTICIPANT COMPENSATION
>
> The Commission recommends that AEMO lodge a rule change request to change the basis of the directed participant compensation framework, creating more certainty as the market transitions, balancing the interests of generators and consumers, and mitigating the potential for inefficient outcomes.

4.3 Affected participant compensation

As discussed in section 4.1.2, "affected participants" are those participants whose dispatch targets change as a result of a direction being issued or the RERT being activated. Such participants may be entitled to receive compensation from AEMO if they were dispatched less as a result of an intervention (whether and to what extent this is true will depend on whether the compensation owing exceeds the $5,000 threshold which currently applies per trading

163 AEMO, Submission to the consultation paper, p. 8. Note that, while the 90th percentile price is projected by AEMO to fall in South Australia, there will be a timelag before this has any notable impacts on the quantum of compensation payable given that the 90th percentile price is based on prices in the preceding 12 months. Given this, leaving the compensation framework as is and relying on the declining level of the 90th percentile price to mitigate the potential need for AEMO to issue more directions will not suffice to offset the relative attractiveness of the 90th percentile price versus the spot price when directions - but not intervention pricing - are in place.

164 The Commission notes that, while total compensation costs may decline, the amount of the "compensation recovery amount" could increase. This is the amount that must be recovered from consumers to "top up" the trading amounts retained by AEMO per clause 3.15.8(b) in order to cover the cost of compensating directed (and affected) participants. If spot prices fall following the removal of intervention pricing, then the amount of retained trading amounts can also be expected to fall, meaning the "top up" provided by the compensation recovery amount may need to increase. However, the Commission considers that the key consideration is the total cost of compensating directed and affected participants - being the sum of trading amounts retained and the compensation recovery amount. Having regard only for the compensation recovery amount provides an inaccurate signal as to the cost of compensation.

interval: as discussed in section 4.4). Affected participants may also be required to repay money to AEMO in the event that they are dispatched more in the dispatch run/"real world" as a result of an intervention (again, this is subject to the application of the $5,000 compensation threshold which currently applies per trading interval).

Compensation is calculated automatically and affected participants can seek additional compensation or dispute their liability to repay funds to AEMO. The cost of compensating affected participants is passed through to market customers and thus consumers.

4.3.1 Issues discussed in the consultation paper

The consultation paper noted that, unlike affected participants following an intervention, no compensation is payable in the event that dispatch targets change as a result of constraints being imposed by NEMDE. This raises the question of why participants affected by intervention events are treated differently to participants under the normal dispatch of the system. Generators do not receive compensation for being constrained off as a result of a network or other constraint. For example, output from South Australian wind farms is constrained above certain levels and no compensation is payable.[165] This is in contrast to the situation where generators typically receive compensation when they are constrained off because of a direction, a related counteraction or NEMDE optimisation in the wake of a direction.

In South Australia, certain combinations of synchronous generators must be online in order to maintain minimum levels of system strength. These combinations cannot easily be formulated as one or more constraints in NEMDE. Instead, AEMO uses directions as a means of meeting the physical requirements on the system to keep it secure. However, had the goal of keeping the system secure been achieved by implementing constraints, or through compliance with the minimum system strength framework, no affected participant compensation would be payable.

Under the minimum system strength framework, if a TNSP contracts with a generator to provide system strength services, the generator can be constrained on as required by AEMO under clause 5.20C.4 of the NER. As a result of delivering system strength services via a constraint rather than via a direction, no affected participant compensation is payable to other generators whose dispatch targets are impacted as a result of the generator being constrained on.

The Commission is also aware that, in at least one instance, no compensation was payable to a participant who was directed to reduce output in order to restore the power system to a secure state.[166] This raises questions about the appropriateness of paying compensation to affected participants when their output is reduced not as a result of a direction but due to NEMDE optimisation subsequent to a direction.

165 In the third quarter of 2018, for example, 10 per cent of SA wind was spilled due to these constraints which bound 26 per cent of the time.

166 Synergies, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017.

Indeed, if NEMDE did not adjust dispatch targets in the wake of an intervention event, the result could be an insecure power system (as too much generation relative to demand can lead to frequency issues). As such, NEMDE optimisation of dispatch targets is a necessary step to maintain system security.

The consultation paper considered whether affected participant compensation should be retained, or whether it should only apply in certain circumstances (e.g. reliability events as distinct from security events).

4.3.2 Stakeholder views

Of the stakeholders who commented on this issue, six supported the retention of affected participant compensation in its current form (AEC, Powershop, SnowyHydro, AGL, Origin and ERM) while three supported limiting the circumstances in which affected participant compensation is paid (TasNetworks, Uniting Communities and AEMO).

Those who supported retaining affected participant compensation in its current form stressed the importance of putting participants in the position they would have been in but for the intervention.

ERM expressed support for fair compensation to affected participants and noted that participants should not receive windfall gains. In particular, ERM suggested that consideration should be given to whether affected participant compensation should be payable when a single entity is both a directed participant and an affected participant. For example, a directed participant will be compensated at the 90th percentile price for the energy it provides under direction. If, consistent with the counteraction requirement imposed by clause 4.8.9(h)(3) and clause 3.8.1(b)(11), AEMO constrains down output from another unit at the same plant (as occurred in February and March 2017), then the generator will receive both directed and affected participant compensation - effectively being paid twice for the same energy output.[167]

Powershop supported the payment of affected participant compensation where interventions occur, but noted that constraints should be used ahead of directions where possible (where constraints are used, no affected participant compensation would be payable).[168]

TasNetworks suggests affected participant compensation should be payable during reliability events when there is an economic rationale for intervention pricing but not during system security events. Whether or not a security outcome is achieved by a constraint or a direction is not a sufficient basis on which to apply a different approach to compensation. Removing affected participant compensation for security events would improve consistency and reduce costs to consumers. This would in turn enhance investment signalling and support achievement of the NEO.[169]

Similarly, AEMO considers that affected participant compensation should only be payable when intervention pricing is applicable – i.e. when there is a scarcity of a market traded

167 ERM, Submission to consultation paper, p. 5.

168 Powershop, Submission to consultation paper, p. 5.

169 TasNetworks, Submission to consultation paper, p. 6.

commodity. No affected participant compensation should be payable in respect of system security directions where there is no scarcity of a market traded commodity.[170]

Uniting Communities supports changes to the compensation framework to eliminate or at least minimise costs to consumers associated with affected participant compensation where there is not a clear and transparent case that it is in the best interests of consumers to pay such compensation. It notes that NEMDE optimises dispatch targets every day in order to keep the system secure, with the implication that compensation for affected participants may not be warranted simply because dispatch targets have been adjusted in the wake of a direction issued to keep the system secure.[171]

Uniting Communities also emphasises the importance of greater transparency in relation to the payment of any necessary compensation to affected participants. It considers this particularly important given that, unlike directed participants, there is potential for affected participants to optimise their position with respect to compensation. In other words, there is potential for such participants to behave in a manner that is not in the best interests of consumers.[172]

Stakeholder views on affected participant compensation are summarised in the table below.

Table 4.2: **Stakeholder views on affected participant compensation**

APPROACH	STAKEHOLDERS
Retain affected participant compensation	AEC, Powershop, SnowyHydro, AGL, Origin and ERM (6)
Limit affected participant compensation - e.g. to reliability events, not security events	TasNetworks, Uniting Communities, AEMO (3)

Source: AEMC analysis

4.3.3 Commission's analysis and conclusions

As discussed in chapter 3, the Commission is of the view that intervention pricing should only apply in circumstances where the intervention is to obtain a service that is traded in the market, meaning that there is a relevant price signal to preserve. Further, the Commission recommends that the requirement on AEMO to issue counteraction instructions should be removed so that, in the wake of an intervention, the NEM dispatch engine (NEMDE) can optimise dispatch targets at least cost. Consistent with this approach, the Commission considers that affected participant compensation should no longer be payable in respect of intervention events for which intervention pricing does not apply (or, more precisely, will not apply once clause 3.9.3 is amended in the manner described in chapter 3 and the Commission's draft rule determination relating to Application of the regional reference node test to the RERT).

170 AEMO, Submission to consultation paper, p. 7.

171 Uniting Communities, Submission to consultation paper, p. 13.

172 ibid

When an intervention event occurs, and assuming the obligation to counteract is removed, the NEMDE will adjust dispatch targets such that they are set at levels which are productively and allocatively efficient. The Commission considers that there is no case to pay affected participant compensation in such circumstances, save for those instances where there is scarcity of a market traded commodity. In such cases, affected participants may be constrained down at a time when they would otherwise receive high prices, reflecting a tight supply demand balance. In such cases, the Commission considers it appropriate to keep such participants "whole" by putting them in the position they would have been in but for the intervention.

Accordingly, the Commission recommends that affected participant compensation be payable only when intervention pricing applies (i.e. when, under draft amendments to clause 3.9.3, an intervention occurs in response to scarcity of a market traded commodity). For directions for system strength and other security services such as voltage control or inertia (i.e. where there is no scarcity of a market traded commodity), affected participant compensation would not in future be payable. This is considered appropriate given that:

- affected participant compensation is a cost to consumers that does not arise when the same outcome is achieved using constraints; removing affected participant compensation for system security interventions will increase consistency as between intervention events and constraints, and reduce costs to consumers.
- affected participant compensation is calculated based on dispatch targets and prices in the intervention pricing run. These dispatch targets are infeasible in the sense that they represent an insecure system which prompted AEMO to intervene in the market to change the generation mix. As such, it is not considered appropriate to compensate participants by reference to dispatch targets and prices which would never be realised in practice.
- analysis by the Commission suggests that participants are able to optimise the amount of affected participant compensation they receive, a practice that is not considered to be in the interests of consumers.

Each of these points is discussed further below.

Interventions v constraints

As discussed in the consultation paper and noted above, no compensation is payable when constraints bind and affect the dispatch targets of market participants. The Commission agrees with TasNetworks' view that whether a security outcome is achieved by a constraint or a direction is not a sufficient basis on which to apply a different approach to compensation, and that removing affected participant compensation would improve consistency and reduce costs to consumers.

Similarly, AEMO submitted that no affected participant compensation should be payable in respect of system security directions where there is no scarcity of a market traded commodity, and Uniting Communities noted that affected participant compensation may not be warranted simply because dispatch targets have been adjusted in the wake of a system security direction.

The similarity between constraints and directions is clearly illustrated in the market event report issued by AEMO following the direction issued to Mortlake Power Station on 1 December 2016. The direction was to desynchronise as the synchronisation of the power station had resulted in unanticipated impacts on interconnector flows.

The report of the event concluded by noting that new constraints had been included in NEMDE in order to constrain Mortlake's output to zero during transmission line outages:[173]

> The constraint equations to manage voltage unbalance at the APD 500 kV transmission busbar were ineffective on 1 December 2016. These constraint equations were formulated to constrain off generation from Mortlake PS during such events. However, the dispatch outcomes as a result of the interaction of these constraint equations with the fast-start inflexibility profile was not envisaged.
>
> The voltage unbalance constraint equations had a constraint violation penalty (CVP) factor of 360, in comparison to a CVP factor of 1130 for the fast-start inflexibility profile. The higher CVP factor for the fast-start inflexibility profile meant that when Mortlake PS Unit 12 came online, the voltage unbalance constraint equations were violated while the generating unit was dispatched in accordance with its fast-start profile.
>
> AEMO has reviewed the Direction issued to Origin Energy in relation to Mortlake Power Station Unit 12 on 1 December 2016 and the circumstances surrounding this Direction, as set out in this report.
>
> AEMO assessed its compliance with the applicable procedures and processes for determining to issue the Direction, notification, and the decision not to implement intervention pricing, and is satisfied all requirements were met.
>
> AEMO has also identified and implemented the following improvements.
>
> 1. Because of the undesirable dispatch outcomes due to the interaction between the voltage unbalance constraint equations and the fast-start inflexibility profiles, AEMO has removed the voltage unbalance constraint equations and replaced them by constraining Mortlake generation to zero MW during future outages involving the transmission lines between Moorabool and Heywood.
>
> 2. System security constraints will be applied to reduce output from generating units to manage power system security violations.

In other words, the original constraint set was ineffective, hence a direction to Mortlake was needed in the circumstances that arose on 1 December 2016. To avoid the need to issue such directions in future, a new constraint set has been created.

While constraints can be difficult to formulate for all security issues (e.g. system strength), this action by AEMO highlights the substitutability of these two tools (directions and

173 AEMO, *NEM Event Report - Direction to Mortlake Generating Unit 12 - 1 December 2016*, November 2017, p. 14.

constraints) to achieve the same outcome, and underscores the case to increase consistency with respect to the compensation requirements that flow from the choice of tool.

Infeasible dispatch targets

As discussed in chapter 3, the Commission is of the view that intervention pricing should not apply in circumstances where there is no economic rationale for it – that is, where there is no relevant market price signal to preserve (e.g. where the direction is for system strength, inertia or voltage control).

Another factor in support of this view is that, in the case of interventions to maintain system security, the intervention pricing run used by NEMDE to determine the intervention price comprises a set of dispatch targets that together constitute an insecure system. This is because the counterfactual intervention pricing run consciously excludes the units that AEMO has directed into service to maintain system security. This is done so that the run can determine what the spot and ancillary service prices would have been had the intervention not occurred.

In practice, the combination of dispatch targets in the intervention pricing run, and the price determined as a function of them, would never have been allowed to be realised (beyond 30 minutes). Accordingly, the Commission considers that this counterfactual is not a valid basis on which to determine the price at which the market clears when a system security intervention is in place, and nor does it provide a valid basis on which to calculate affected participant compensation in the same circumstances.[174]

Ability of participants to optimise affected participant compensation

As noted above, analysis by the Commission suggests that participants are able to optimise the amount of affected participant compensation they receive. This is because the intervention pricing run is a dynamic process which produces notional dispatch targets (for pricing purposes only) every five minutes, just like the dispatch run which is used to set actual dispatch targets for the market in the "real world". Intervention prices are published every five minutes and are automatically available to the market.

Dispatch targets in each run are set having regard for dispatch offers and bids. Given this, it is possible for a participant to optimise its position. When a generator's dispatch targets change due to an intervention and it recognises that it is an affected participant, the generator can optimise its bidding and hence its target in the pricing run in order to optimise its affected participant compensation. [175] The Commission considers that bidding to optimise eligibility for compensation is not in the interests of consumers.

174 The situation is different when an intervention is to address a scarcity of energy. This is because the reliability standard in clause 3.9.3C of the NER reflects that the system is not expected to be "reliable" 100 per cent of the time. As such, the dispatch targets underpinning the intervention pricing run can be considered feasible even if they represent an "unreliable" system which has prompted AEMO to intervene.

175 Where a participant is actually dispatched more as a result of the direction, it will need to repay additional revenue earned to AEMO, net of additional costs incurred. This occurs when a unit's dispatch targets in the dispatch run are higher than those in the intervention pricing run.

In the period April 2017 to April 2019, a total of just under $4.7m was paid out to a group of 25 participants who were affected[176] at various times by system strength directions.[177] This represents the amount automatically calculated by AEMO. In addition, AEMO paid out more than $400,000 in additional compensation to two claimants in respect of five intervention events (giving a total affected participant compensation payout of $5.1m).

During that two year period, payments to affected participants were made on 181 occasions. By contrast, a total of just over $1m was repaid by affected participants to AEMO across 52 occasions. (The fact that repayments to AEMO are smaller than payments by AEMO is not surprising. This is because, when AEMO directs on gas fired generators in South Australia, other scheduled generators across the NEM will typically be dispatched less, not more, than would have occurred but for the intervention.)

The net result is that just under $4.1m was paid out to affected participants (taking into account both payments to and from affected participants) and recovered from South Australian market customers, and thus end consumers, via the "compensation recovery amount".

While these sums are not large when considered in the context of the volume of energy traded in the NEM, it is nonetheless important to consider whether affected participant compensation is warranted and appropriate in connection with system security directions. The Commission notes that market customers and consumers cannot manage the risk created by the requirement to pay affected participant compensation costs (in addition to directed participant compensation and higher wholesale prices when intervention pricing is invoked).

Of the automatically calculated compensation (total of ~$4.7m), a significant proportion was paid to a group of three affected participants. The ratio of compensation paid by AEMO to this group compared with revenue repaid by them to AEMO was in excess of 9:1. By contrast, the ratio for other generators who received numerous payments were either around or somewhat below a ratio of 3:1.

Within this group of three, one participant has received more than 30 per cent of the total amount of automatically calculated compensation paid out by AEMO to affected participants. This participant received compensation on 43 occasions (representing 23 per cent of instances when AEMO paid compensation to affected participants) and only had to repay revenue to AEMO on two occasions. The quantum of its average payment across these 43 occasions was 40 per cent higher than the average of all payments made by AEMO to affected participants.

The Commission's analysis indicates that a participant in South Australia was also a major recipient of affected participant compensation, underscoring the concerns raised by ERM that some participants may be receiving both directed and affected participant compensation. This may (depending on the circumstances) constitute paying twice for the same energy, an issue

176 That is, their dispatch targets changed.

177 AEMC analysis of data provided by AEMO.

that has implications for costs borne by consumers. (The extent to which this occurs is difficult to ascertain based on the data available to the Commission).

The Commission agrees with ERM's support for "'fair' compensation to any party who is financially disadvantaged by the invoking of market intervention". ERM also considers that "no party should receive a 'windfall' gain due to market intervention".[178] The Commission shares this view, although noting that the Commission has reached a different conclusion to ERM (ERM supports changing the $5,000 compensation threshold with respect to both affected and directed participants, whereas the Commission recommends that this change be made only in relation to directed participants).

The Commission also shares Uniting Communities' concern that there is potential for participants to behave in manner that is not in the best interests of consumers, and their view that affected participant compensation should not be paid where there is not a clear and transparent case for it. The Commission notes that the 2000 Review of directions by NEMMCO and NECA recommended that "third parties whose market dispatch is affected by a direction should be compensated so that their financial position is *unaffected* by the direction" [emphasis added].[179]

The above analysis suggests that affected participant compensation is not achieving this objective: rather than simply shielding participants from losses arising from a direction to another party, as appears to have been intended, several participants are benefiting significantly from the payment of affected participant compensation. Thus, their financial position is positively "affected", rather than kept neutral, and consumers are bearing the cost of this.

Given that affected participant compensation is not payable where constraints are used, and that dispatch targets in intervention pricing runs are both infeasible (for system security directions) and open to participant influence, the Commission considers that affected participant compensation is not warranted in connection with system security interventions and nor is it in the interests of consumers. Accordingly, the Commission recommends that eligibility for affected participant compensation be narrowed to those instances where intervention pricing is triggered in accordance with the revised regional reference node test, and should not be payable when interventions occur in response to system security issues.

The Commission acknowledges that, where an intervention does trigger intervention pricing, the potential for affected participants to optimise their position with respect to compensation will in theory remain. However, two factors suggest the potential implications of such behaviour for consumers are limited in this instance.

First, there have only been two reliability directions since 2010, with a combined duration of four hours and five minutes. This reflects the incentive for participants to participate in the market and earn the spot price when the supply demand balance is tight (in such instances, this will be more attractive than receiving the 90th percentile price under direction).

178 ERM, Submission to consultation paper, p. 9.

179 NEMMCO and NECA, *Power system directions in the National Electricity Market*, May 2000, p. i.

This is in stark contrast to the recent use of directions for security reasons. During 2018, system strength directions were in place for 30 per cent of the time on average. While the RERT has been dispatched on four occasions in the last two years, very limited affected participant compensation has been payable given the circumstances in which the RERT was dispatched (i.e. inadequate reserves or anticipated load shedding).

Secondly, during a reliabiltiy event, the extent to which other participants are "affected" (i.e. dispatched differently) due to the intervention is likely to be limited. This is because the supply demand balance in such instances is tight, and thus any change in dispatch targets is likely to be limited and/or shortlived. For example, when AEMO directed Pelican Point into service to provide more headroom on two occasions in February and March 2017, other units were turned down to offset the impact of the direction.

A subsequent increase in demand would likely restore the dispatch targets of affected participants to (or close to) the level that applied before the direction was issued. If demand did not increase as forecast, AEMO would need to cancel the direction in accordance with its obligation to revoke directions as soon as they are no longer required.

Accordingly, the Commission considers that the potential impact on consumers of affected participants optimising their compensation position during reliability events is limited, particularly noting the infrequent nature and short duration of reliability directions. For this reason, the Commission considers that – notwithstanding the theoretical potential for affected participants to optimise their position – it is appropriate for affected participants to be compensated during reliability events so that they are "made whole" rather than losing revenue as a consequence of an intervention.

The Commission notes that, while changing the NER to narrow eligibility for affected participant compensation will reduce the amount of compensation paid to affected participants by AEMO, it will also reduce the liability of affected participants to repay funds to AEMO.

Removing the obligation on AEMO to apply counteraction constraints[180] is, all else equal, expected to reduce the impact of an intervention event on any one participant. Instead, in the wake of an intervention event, NEMDE will be free to optimise dispatch targets at least cost - a process that occurs in every dispatch interval of every day. This will reduce the distortionary impact of the intervention event and further reduce the case for paying compensation to affected participants in the wake of system security directions (particularly to those who might otherwise experience significant changes to their dispatch targets as a result of targeted counteraction instructions).

As noted by ERM in its submission, some affected participants may also receive directed participant compensation - thus being paid twice for the same energy output.[181] While removing the counteraction requirement may reduce the likelihood of this occurring, it would still be possible for this situation to arise: for example if AEMO directs on one generating unit,

180 These are used by AEMO to "manually" adjust dispatch targets in order to confine the impact of an intervention event to a single market participant, where possible, or a single region.

181 ERM, Submission to consultation paper, p. 5.

and another unit at the same power station is the marginal generator at that time, NEMDE could automatically constrain down the latter unit as part of the least cost optimisation process.

During a reliability event, this could result in very significant compensation being paid to a single generator: one unit would be compensated for its output at the 90th percentile price while the constrained down unit would be compensated for its reduced output based on the market price (which during a reliability event is likely to be very high). This would effectively mean paying the generator twice for the same energy output. This issue warrants further examination to ensure that the affected participant compensation framework does not confer unwarranted costs on consumers in such circumstances.

The Commission recognises that the issue of affected participant compensation touches on matters being progressed through the Coordination of Generation and Transmission Investment (COGATI) project. It is possible that future changes to access arrangements may mean that participants who have paid for firm access to the market will be compensated in the event that they bid available but are not dispatched or dispatched in full. If such changes were to be made, the Commission considers that the more appropriate avenue for compensating these generators would be through the access regime, and it would not be necessary to pay additional compensation under the affected participant framework. Accordingly, the Commission considers the proposed approach to be appropriate and consistent with the NEO.

4.3.4 Recommendation

> RECOMMENDATION 3: NARROWING ELIGIBILITY FOR AFFECTED PARTICIPANT COMPENSATION
>
> The Commission recommends that AEMO submit a rule change request to narrow the circumstances in which affected participant compensation is payable (limiting it to those instances where intervention pricing applies in connection with an intervention event in accordance with the revised regional reference node test). This would reduce inconsistency as between directions and constraints, and reduce cost impacts on consumers. This rule change request could also examine how best to mitigate the risk of passing through unnecessary compensation costs to consumers in circumstances where an entity is eligible for both directed and affected participant compensation.

4.4 Compensation threshold rule change request

At present, the NER includes a $5,000 threshold which limits the payment of compensation both to and by "affected participants" (those participants whose dispatch targets change following an intervention).[182] The threshold also applies to directed participants such that

182 NER, clauses 3.12.2.

they may only lodge a claim for additional compensation if the claim exceeds $5,000 per trading interval.[183]

AEMO has submitted a rule change request which seeks to change the threshold so it applies per intervention event, rather than per trading interval, as currently. Consultation on this rule change request was initiated by the consultation paper which posed the following questions:

- Should the $5000 threshold apply per trading interval or per intervention as proposed by AEMO?
- If it is to apply per event should the quantum remain the same or change?
- If the latter, how should the quantum be determined? For example should it be a set amount or determined based on case specific criteria such as the length of the intervention event or the quantum of the compensation claimed or payable?
- Should the same approach be adopted with respect to both affected and directed participants or does a differentiated approach warrant consideration?
- To promote transparency and predictability, should there be any more clarity regarding how AEMO determines the length of a given intervention event?

4.4.1 Stakeholder views

AGL, AEC, EnergyAustralia, Engie, Powershop, Origin and SnowyHydro support AEMO's proposal to apply the $5,000 threshold per event rather than per trading interval as this will prevent market participants being adversely affected where an intervention event comprises a number of trading intervals.

AGL notes that, if the threshold is to apply per event as proposed by AEMO, it may be appropriate to raise the quantum to a higher set amount. (No detail as to how this might be determined was offered.) TasNetworks and Engie consider that setting the threshold at a particular level or reference point needs further consideration.

AEMO notes the purpose of the threshold is to prevent or limit claims for which the processing and determination costs are likely to exceed the compensation payable. It notes that its determination costs are approximately $5,000 per event and that the administrative cost of determining compensation to/from affected participants is not materially different to the administrative cost of processing additional compensation claims from directed participants. As such, it does not believe that different compensation thresholds should apply to directed and affected participants.

Stakeholder views are summarised in the table below.

Table 4.3: Stakeholder views on compensation threshold

APPROACH	STAKEHOLDERS
Change threshold to apply per event	AGL, AEC, EA, ERM, Powershop, SnowyHydro, Origin (7)

183 NER, clause 3.15.7B.

APPROACH	STAKEHOLDERS
Continue to apply per trading interval	None
Further consider threshold quantum	AGL, Engie, TasNetworks (3)

Source: AEMC analysis

4.4.2 Commission's analysis and conclusion

The Commission considers that it is appropriate for the rules to enable directed participants to recover the costs they incur when providing a service under direction. If this necessitates an additional compensation claim, the application of a "per trading interval" threshold should not limit the amount of compensation that can be paid such that directed participants incur loss. Accordingly, the Commission agrees with AEMO that the compensation threshold should apply per intervention event in such instances (or, more particularly, "per direction" in the case of directed participant additional compensation claims). Based on advice from AEMO as to its administrative costs, the Commission considers it appropriate to leave the quantum of the threshold at its present level.

The Commission does not propose to change the $5,000 threshold in the manner proposed by AEMO in respect of affected participants. This reflects the recommendation in section 4.3.4 that affected participant compensation should only be payable in relation to intervention events which trigger intervention pricing, and in turn the draft determination discussed in chapter 3 which provides that intervention pricing should only be triggered where there is a relevant market price signal to preserve (i.e. where there is scarcity of a market traded commodity).

The Commission also notes that the proposal to apply the threshold on a per event basis rather than a per trading interval basis would significantly increase the quantum of compensation payable to affected participants.

In its rule change request relating to the participant compensation threshold, AEMO estimates that adopting a per event threshold would have resulted in an increase in affected participant compensation payments of $1.4 million in the third quarter of 2018.[184] The Commission notes that, during the third quarter of 2018, directions were in place for just under 30 per cent of the time (see figure 2.1 on page 8). As such, this quarter is roughly representative of the use of directions over the 2018 calendar year, noting that directions were in place for around 30 per cent of the time on average during 2018.

To provide some indication of the impact of the proposed rule change over time, the $1.4 million figure can be multiplied by four to derive an indicative annual cost estimate of $5.6 million. While this estimate is based on extrapolation of available data, it gives some idea of the cost implications of the proposed rule change.

As noted above, just under $4.1 million has been paid out in affected participant compensation (net of revenue paid back to AEMO by affected participants) in the period April

184 AEMO, Rule change request, op cit, p. 7.

2017 to April 2019. Again for the purposes of deriving an indicative annual cost estimate, halving this total net payout gives an annual net affected participant compensation cost of $2.05 million.

As can be seen, the potential impact of adopting a per trading interval compensation threshold is not insignificant, potentially increasing net payments of affected participant compensation from around $2.05 million per annum to around $7.65 million per annum (again, based on extrapolation from available data). This equates to more than a threefold increase in annual compensation costs recovered from market customers and, ultimately, consumers.

For these reasons, the draft determination for this rule change request sets out a more preferable rule in which the change to the $5,000 threshold is made in relation to directed participants' additional cost claims but not in relation to the compensation payable to affected participants. The Commission recommends that the change to the affected participant compensation threshold be considered at such time as a rule change request is submitted to narrow eligibility for affected participant compensation in the manner outlined above. This will avoid significantly increasing the level of compensation paid to affected participants, and thus costs to consumers - contrary to the NEO, when it is envisaged that eligibility for such compensation should be narrowed substantially.

4.4.3 Draft determination

DRAFT DETERMINATION: CHANGING COMPENSATION THRESHOLD ONLY FOR DIRECTED PARTICIPANTS

The Commission has determined that the compensation threshold for directed participant additional compensation claims should apply on a per direction basis, rather than per trading interval. The quantum of the threshold should remain at $5,000.

However, the Commission does not propose to amend the threshold for affected participants given its view that eligibility for affected participant compensation should be narrowed, as recommended in section 4.3.4. Allowing for the payment of more affected participant compensation at this time is not considered to be consistent with the NEO.

4.5 Transparency about compensation payments

The consultation paper noted that there is very little transparency in relation to the quantum of compensation paid to directed and affected participants. This is concerning given that compensation costs are ultimately borne by consumers and that, in the case of affected participants, participants can seek to optimise their position in respect of the amount of compensation payable.

In responding to the consultation paper, several stakeholders expressed concern about this lack of transparency regarding compensation payments, as well as a more general lack of transparency due to the time lag between intervention events and AEMO market event reports.

The consultation paper asked:

- Should changes be made to increase clarity and consistency regarding the determination of compensation payments?
- Should the NER set out the basis for recovering affected participant compensation costs following RERT activations?

4.5.1 Issues discussed in the consultation paper

The level of information currently published regarding the cost of compensation is very limited and is aggregated to such a degree that there is no visibility as to the share of compensation being paid to directed participants and affected participants. Under clause 3.13.6A(b) of the NER, AEMO is only required to publish the "compensation recovery amount" (CRA), being the amount recovered directly from market customers and thus consumers to "top up" the trading amounts retained by AEMO (per clause 3.15.8(b)) when it directs a generator to provide services.

The quantum of compensation paid to individual directed and to or by affected participants is only publicly available where an independent expert report has been prepared and that report identifies the directed or affected participant. Such reports are prepared where an independent expert has been engaged by AEMO to assess a claim for additional compensation (beyond that automatically paid to directed or affected participants), where an affected participant disputes the amount it is required to pay AEMO or where, in order to compensate a directed participant who provided a service other than energy or FCAS, it is necessary to determine a "fair payment price" for that service.[185] Since January 2016, only six such independent expert reports have been prepared.[186] Of these, only three identify both the participant and the compensation payable.

While the NER do prohibit independent experts from including in their "fair payment price" report the identity of a directed participant,[187] there is no such prohibition in the clause relating to other independent expert reports (e.g. where a directed or affected participant lodges a claim for additional compensation or disputes an amount payable to AEMO).[188] As such, the legal basis for the current lack of transparency is not clear.

In practice, it is possible in some cases to identify the relevant participant by looking at the relevant AEMO market event report (if it has been published) even if the participant is not identified in the independent expert report. In one recent case, a draft independent expert report regarding fair payment price compensation identified the participant in question, despite this being prohibited. The draft report cited the AEMO operating incident report which

185 See clauses 3.15.7A and 3.15.7B of the NER.

186 Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports While other such reports have been prepared in the past, these are considered outdated and are no longer made available on the AEMO website.

187 Clause 3.15.7A(c)(5) of the NER.

188 Clause 3.12.3(c)(5) of the NER.

had already identified the participant as Snowy Hydro.[189] By contrast, the final version of the same report makes no reference to Snowy Hydro Ltd, and the reference to the AEMO operating incident report identifying Snowy Hydro has also been removed.[190]

The Commission considers that it would be sensible and appropriate to create a consistent set of requirements that enhances transparency while protecting the confidentiality of data that is actually commercially sensitive.

Where additional cost claims or disputes regarding compensation liability are relatively small (such that there is no need to engage an independent expert), AEMO deals with the claims in-house and no information regarding such claims is made public.

While AEMO is required to publish market event reports following the issuance of a direction, there is no specific time by which these reports must be published.[191] Clause 3.13.6A requires AEMO to publish a report "as soon as reasonably practicable" after issuing a direction. That clause sets out a number of matters that need to be included in the reports but this does not include any detail about the amount of compensation that was paid in connection with the direction. The only cost information that AEMO must publish is the compensation recovery amount arising from the direction and a breakdown of the CRA by each category of registered participant (as determined by AEMO) in each region.

The lack of a precise time by which reports must be published means that there is a significant timelag between the issuance of a direction and the report published in relation to that direction. The Commission acknowledges that AEMO has recently published a number of additional market event reports that were not available when the consultation paper was published. These latest reports cover system strength directions up to October 2018. Many directions have been issued since then for which reports are yet to be prepared.

4.5.2 Stakeholder views

Powershop, TasNetworks, EnergyAustralia, ERM, Energy Queensland, Uniting Communities and PIAC support changes to the NER to increase clarity and consistency around compensation payments, including outlining the basis on which affected participant compensation costs are recovered following RERT activations.

Several stakeholders were concerned about AEMO reporting delays and resulting lack of transparency. SnowyHydro and Origin suggested the NER should be amended to oblige AEMO to issue reports in a timely manner. AEC and SnowyHydro suggested AEMO should provide summary factual evidence within a reasonable period after intervening, followed by a second more detailed qualitative report within three months.

Similarly, EnergyAustralia suggested that, in place of reporting on common system security intervention events (e.g. SA system strength directions), AEMO could publish a simple table

189 IES, *AEMO direction to a NSW participant on 24 Jan 2019 to operate a unit as a synchronous condenser - Draft report*, May 2019, p. iii.

190 IES, *AEMO direction to a NSW participant on 24 Jan 2019 to operate a unit as a synchronous condenser - Final report,* July 2019.

191 NER, clauses 4.8.9(f) and 3.13.6A(a).

setting out high-level reasons for the event (for common events only), AEMO's timeline of actions, directed units and intervention intervals, among other things.[192]

ERM believes "increased transparency in this area is warranted, with additional details regarding the total of payments received from affected participants disclosed in the market intervention report prepared by AEMO. We do not believe that reporting of payments on an individual participant basis is required and would present an unnecessary administrative burden on AEMO. In addition, the market intervention reports should detail the recovery of any costs from market customers on a regional basis".[193]

AGL does not agree with publishing the details of compensation paid or the identities of compensated participants on the basis that the NER set out precisely how compensation is calculated.[194] (The Commission notes however that, while the NER do set out the basis for compensation, these provisions do not resolve concerns about lack of information about the quantum and frequency of compensation payments.)

While Energy Queensland does not support commercially sensitive information being made public, it supports an approach that provides "as much transparency as possible, given customers ultimately pay compensation".[195]

Uniting Communities states that much greater transparency is urgently needed regarding compensation and related payments. This should include reporting, preferably quarterly but at least annually, on all intervention pricing and compensation payments made on a generator by generator basis.[196]

AEMO notes that "there are presently conflicting indications in the Rules that indicate confidentiality of individual amounts, yet a requirement for the independent expert report to include total direction compensation will reveal an individual amount where there is only one directed participant. AEMO welcomes certainty in the Rules as to the level of detail to be published on compensation amounts."[197]

4.5.3 Commission's analysis and conclusions

The Commission agrees with stakeholders that greater transparency is required. This is particularly important given the frequent use of directions, the costs being passed through to consumers and the ability of affected participants to optimise their position in respect of eligibility for compensation.

Stakeholders also expressed concern about the timelag between intervention events and the market event reports that AEMO is required to publish. As noted above, the requirement to publish reports does not include an explicit timeframe and hence publication of these reports has fallen behind. This is not surprising given the labour intensive nature of the directions

192 EnergyAustralia, Submission to the consultation paper, p. 3.
193 ERM, Submission to the consultation paper, p. 9.
194 AGL, Submission to the consultation paper, p. 4.
195 Energy Queensland, Submission to the consultation paper, p. 2.
196 Uniting Communities, Submission to the consultation paper, p. 14.
197 AEMO, Submission to the consultation paper, p. 7.

process and the unprecedented number of directions issued in South Australia over the past two years. The Commission notes, however, that while the Rules require detailed reports to be published, there is nothing preventing AEMO from publishing summary data in the first instance, until such time as the detailed reports are able to be published. The Commission considers that this would be a useful step to keep the market and policy-makers informed in a timely way about the nature and extent of recent directions.

Recent rule determinations provide examples as to how transparency can be enhanced. For example, the final determination for *Participant compensation following market suspension* included new provisions designed to increase transparency.[198] In particular, following a period during which spot prices are set by the market suspension pricing schedule (MSPS), AEMO will report publicly on the quantum of MSPS revenue and, if applicable, compensation paid to each eligible claimant, and the share of compensation costs payable by each Market Customer (as determined by AEMO under clause 3.15.8A).

Similarly, the final determination for the *Enhancement to the RERT* also included provisions designed to enhance transparency with the aim of better informing market participants, policy makers, consumers and other interested parties about the costs of the RERT and what is driving the use of the RERT. Increasing the amount of information available can in turn guide these parties to make more informed operational and investment decisions, as well as to better budget and plan for RERT related charges. Under the final determination:

- AEMO is to publish a quarterly RERT report, if necessary due to the addition of new information, covering both forward-looking data (indicative costs of emergency reserves, and analysis of any procurement of emergency reserves); and backward-looking data (updated emergency reserve costs and volumes, forecasts that indicated RERT intervention was required, impact on market reliability)
- AEMO is to publish a report within five business days of the dispatch/activation of the RERT, detailing preliminary estimated RERT costs and estimated volumes of emergency reserves dispatched/activated
- AEMO is to maintain a methodology report, explaining how it determined the amount of emergency reserves to procure, as part of its RERT procedures

Given that AEMO intervention events comprise both the RERT and directions, the Commission considers it appropriate to increase the level of transparency relating to directions and associated costs, consistent with the approach adopted in relation to the RERT.

In particular, the Commission considers it appropriate to impose clear requirements on AEMO to publish information in a timely manner and increase transparency around the compensation costs associated with intervention events which are ultimately borne by consumers. This would complement the proposal to adopt a cost minimisation principle in relation to the choice of intervention mechanism (in place of the current hierarchy which prioritises the RERT ahead of directions and instructions), as discussed in chapter 6.

198 AEMC, *Participant compensation following market suspension - Rule determination*, November 2018

The Commission is not suggesting that commercially sensitive information should be disclosed. However, the Commission considers that greater transparency regarding the quantum of compensation paid to individual participants is warranted since this can shed light on any bidding behaviour patterns that may be adopted to maximise the payment of compensation at the expense of consumers. This is particularly important while ever affected participant compensation remains payable in respect of intervention events for which intervention pricing does not apply (under the amended "regional reference node test", as discussed in chapter 3 and outlined in the Commission's draft rule determination relating to the regional reference node test following activation of the RERT).

In relation to the RERT, information about compensation payments to individual affected participants would also be valuable in that it would provide information to the market as to whether any generators were constrained down in response to the activation of the RERT (see further below in section 4.6). At present, only aggregate data is public and thus it is not possible to ascertain whether affected participant compensation was paid to generators who were constrained down or to SRD unit holders who were impacted as a result of changes to interconnector flows. Greater clarity regarding these impacts could usefully inform deliberations about whether the activation of the RERT was optimally timed and efficient.

There are no directed participants in the case of the RERT: instead, parties which provide services under the RERT are compensated under the terms of their individually negotiated contract. The Enhanced RERT determination did not require publication of data regarding the cost of individual RERT providers on the basis that it was not convinced that the additional benefit gained from the publication of the characteristics and costs of individual providers would outweigh confidentiality concerns. However, the Commission considers that different considerations are relevant in relation to directions. Directed participant compensation is calculated based on a formula not, as is the case with the RERT, based on the negotiation of individual contracts through an open tender process.

Transparency at the individual directed and affected participant level is considered beneficial as a means to temper the potential inefficiencies that can flow from bidding behaviour designed to maximise the payment of compensation. Given this, the Commission considers it appropriate to require publication of data at the individual participant level, consistent with the approach adopted in the market suspension compensation determination. As discussed earlier, market participants have the ability to influence whether AEMO needs to issue a direction and, if one is issued, how much compensation an affected participant may be entitled to receive (based on the difference in dispatch targets arising from the intervention).

As noted in the consultation paper, the AER has raised questions about generator behaviour in the lead up to directions being issued. It noted that registered participants "must not by any act or omission, whether intentionally or recklessly, cause or significantly contribute to the circumstances causing a direction to be issued, without reasonable cause....We are currently considering the conduct of some scheduled generators who have advised AEMO of their intention to desynchronise at shorter notice than is required by clause 4.9.7(a) of the Electricity Rules. Further, we are examining whether this has led to AEMO issuing directions to generators to remain synchronised, to ensure the market remains in a secure operating state. AEMO has observed an increase in the frequency of this behaviour over recent months. We are considering how the Electricity Rules should be applied in this context and working with AEMO to better understand the drivers of these behaviours."[199]

The Commission considers that greater transparency about compensation payments to individual participants may help to dissuade any generator behaviour that raises compliance concerns such as those noted above, or risks inefficiently increasing costs to consumers, contrary to the NEO. To be clear, the Commission does not propose that commercially sensitive information (such as may be contained in claims for additional compensation) should be published. However, there is a case to require publication of a reasonable amount of data in a regular and timely manner - not just in those instances where an additional claim or liability dispute has resulted in the publication of a report setting out the compensation paid in a given instance.

4.5.4 Recommendation

RECOMMENDATION 5: INCREASED TRANSPARENCY

The Commission recommends that the AER lodge a rule change request to amend the NER so as to:

- impose a clear requirement on AEMO to publish its directions reports within a clearly defined period (consideration could be given to requiring the publication of high level reports shortly after the event, similar to the approach adopted in relation to the RERT, followed by more detailed reports once compensation costs are known)
- require reports to include information regarding the amount of compensation payable to each directed and affected participant
- require AEMO to publish information about additional compensation claims or disputes dealt with in-house
- require independent expert reports to identify the directed or affected participant and the quantum of compensation payable.

4.6 Recovering affected participant compensation following RERT activation

The consultation paper noted that, while the NER provide for most RERT related costs to be recovered from market customers in the relevant region,[200] there is currently a gap in the rules in relation to recovering the cost of affected participant compensation following activation of the RERT. This issue was discussed by the AEMO-established Intervention Pricing Working Group (IPWG) which agreed that a rule change request should be submitted to rectify this gap in the rules.

199 AER, Quarterly Compliance Report: National Electricity and Gas Laws, 1 January - 31 March 2018

200 NER, clause 3.15.9(e).

Only one stakeholder, TasNetworks, responded to the consultation paper question regarding this issue. It expressed support for amending the NER to provide a clear basis for recovering the cost of affected participant compensation following a RERT activation. The Commission shares this view, and notes that a change to the NER to rectify this gap would not result in an increase in compensation costs passed through to consumers. It would simply formalise the approach that AEMO had adopted to date to deal with this issue.

Consistent with the discussion above regarding transparency, the Commission considers that there would be merit in requiring an appropriate level of transparency regarding the payment of compensation to individual affected participants (for example by including appropriate reporting provisions in clause 3.20.6). While the Enhanced RERT final determination included a number of new provisions to enhance transparency, this issue was not addressed as cost recovery of affected participant compensation was outside the scope of the rule change request.

Providing more information about the payment of compensation to individual affected participants would be beneficial as it would, for example, shed light on whether the activation of the RERT resulted in affected participant compensation being paid to generators that were turned down in response to the RERT activation (as distinct from SRD unit holders[201], who are also eligible to receive affected participant compensation if interconnector flows change as a result of a RERT activation).

Output from in-market generators could be reduced if, for example, AEMO dispatched the RERT for a period which (due to minimum run times) exceeded the duration of the projected shortfall. In such circumstances, AEMO may need to turn down in-market generation in order to ensure an appropriate supply demand balance. Failure to do so could create security issues, for example relating to over-frequency.

A similar situation arose during a reliability event on 9 February 2017 when, in response to an LOR 2 condition, AEMO directed on Pelican Point GT 12 in order to create additional headroom (that is, ensuring sufficient units were online and able to increase output as demand rose). To keep the system in balance, AEMO turned down one other unit at Pelican Point as well as other generating units at Mintaro and Dry Creek.[202] A similar approach was adopted when AEMO again directed on Pelican Point for reliability reasons on 1 March 2017.[203]

Providing more granular information about the payment of affected participant compensation (including whether the participants are generators or SRD unit holders) would in turn shed light on compliance by AEMO with the proposed cost minimisation principle regarding the choice of intervention mechanisms. The level of information that AEMO currently reports does not provide sufficient detail to enable such analysis. The Commission therefore recommends

201 SRD is shorthand for settlements residue distribution agreements. A SRD unit is defined in chapter 10 of the NER as "a unit that represents a right for an eligible person to receive a portion of the net settlements residue under clause 3.6.5 allocated to a directional interconnector for the period specified in a SRD agreement entered into between that eligible person and AEMO in respect of that right". These units are auctioned off by AEMO as part of the process of managing inter regional settlement residues.

202 AEMO, *NEM Event - Direction to South Australia Generator - 9 February 2017*, July 2017, pp. 5-6.

203 AEMO, *NEM Event - Direction to South Australia Generator - 1 March* 2017, January 2018, p. 7.

that the rules be amended to provide greater transparency regarding the compensation costs associated with the RERT, including payments to individual affected participants, consistent with the recommendations in section 4.5 regarding compensation costs associated with directions.

RECOMMENDATION 6: AFFECTED PARTICIPANT COMPENSATION FOLLOWING RERT ACTIVATION

The Commission recommends that AEMO submit a rule change request to amend the NER in order to:

- provide a clear basis on which to recover affected participant compensation costs due to a RERT activation from market customers in the relevant region
- include a requirement in the rules to report on the payment of compensation to individual affected participants following a RERT activation

5 HIERARCHY OF AND PRINCIPLES FOR INTERVENTION MECHANISMS

BOX 3: SUMMARY

Hierarchy of intervention mechanisms

The NER outlines a two-level hierarchy for the use of the intervention mechanisms. In times of "supply scarcity", after dispatching all valid bids and offers, AEMO must use reasonable endeavours to first exercise the RERT (if it has been procured) and then, if necessary, issue either directions or instructions.

The NER do not specify a priority as between directions (which require registered participants to take action in relation to scheduled plant and market generating units) and instructions (which require registered participants to take action other than in relation to scheduled plant and market generating units). The criterion for triggering the use of directions and instructions is the same for each mechanism: "to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state".

In practice, however, AEMO uses directions first (for example, to manage an actual or forecast LOR 2 condition) and instructions to shed load only very rarely (as a last resort to maintain system security when a LOR3 condition occurs).

AEMO’s obligation to follow this sequence of steps is a "reasonable endeavours" obligation. That is, AEMO will be taken to have satisfied its obligation if it can demonstrate it has taken all action that is reasonable for it to take in the circumstances.

This investigation has considered the hierarchy of intervention mechanisms set out in the NER, in particular the requirement that, where the RERT has been procured, it should be used in preference to directions and instructions. In doing so, the Commission examined the costs associated with intervention mechanisms, as well as practical considerations.

There are two main types of costs associated with interventions:

- the direct costs of interventions, which are separate from, and in addition to, spot prices (for example, the contractual costs of RERT and the compensation costs associated with AEMO intervention events)
- the indirect costs of interventions, which are more difficult to quantify, such as the disincentive interventions create for investment by market participants.

These costs, unlike the costs associated with spot pricing and the energy market, are rarely known in advance and cannot be hedged. The costs of interventions are therefore generally more expensive compared to hedgeable market costs. These costs are eventually borne by consumers.

At the same time, there are practical considerations when it comes to which mechanism to

use - each supply scarcity event is different, and the characteristics of RERT contracts and units available to be directed may vary from event to event, as may the costs. As a result, the Commission considers that a cost minimisation approach that maintains flexibility will deliver the best outcome for consumers.

In order to promote this type of approach, the Commission considers that it would be appropriate to replace the existing hierarchy with one which is based on a principle of minimising direct and indirect costs to consumers, while also having regard to the effectiveness of an intervention. This provides AEMO with the flexibility to choose the most effective course of action during a supply scarcity, while minimising costs for consumers.

Recommendation: Introduce a new principle to guide AEMO in prioritising the use of RERT, directions and instructions. The principle would reflect that prioritisation should minimise direct and indirect costs and maximise effectiveness of the intervention.

Counteractions

In order to minimise the number of affected participants and impact on interconnector flows, AEMO may counteract the impact of an intervention by manually adjusting the dispatch targets of certain market participants. For example, it may direct on a unit at a power station and constrain down output from another unit at the same station, or at another station owned by the same participant. This has the effect of limiting the number of affected participants.

Where it is not possible to confine the impact of a direction to a single participant, AEMO will if practicable issue counteraction instructions to another participant in the same region. This aims to confine the effect of the direction to a single region, thereby limiting impacts on interconnector flows.

Counteractions have not generally been used in connection with system strength directions in South Australia because there are rarely scheduled generators operating at levels above their minimum loading such that they can be constrained down to offset the impact of a direction to another scheduled generating unit to come online. AEMO has not been counteracting on wind because its systems do not support automatic invocation of counteraction constraints which means that counteractions are implemented manually. As the output of wind farms is intermittent, it is difficult to manage manual counteraction on such plant types.

Where AEMO is not able to issue "manual" counteraction instructions (for example where there is no unit available within a region for counteraction), NEMDE will automatically optimise dispatch targets across the NEM to offset the impact of the direction. For example, when AEMO directs on gas fired generators in South Australia to provide system strength services, other generators across the NEM will automatically be constrained down to keep supply and demand in balance. This automatic optimisation process is done on a least-cost basis (whereas manual counteraction by AEMO is designed to limit the number of affected participants and impacts on interconnector flows).

The consultation paper considered whether the counteraction requirement should remain or whether it is preferable to allow NEMDE to optimise dispatch at least cost. The Commission considers that requiring AEMO to manually adjust dispatch targets in order to limit the number of affected participants and confine the impact of an intervention to a single region can increase costs compared with the alternative of allowing NEMDE to optimise targets automatically (at least cost) in the wake of an intervention event. The Commission's view is that cost minimisation is a more important objective than minimising the number of affected participants and impact on interconnector flows.

Recommendation: AEMO to submit a rule change request to remove the requirement on AEMO to issue counteraction instructions in order to minimise, in connection with AEMO intervention events, the number of affected participants and the impact on interconnector flows. Instead, NEMDE should be allowed to optimise dispatch targets at least cost in the wake of an intervention event.

This chapter examines issues relating to the existing hierarchy of intervention mechanisms set out in the national electricity rules (NER) and the principles that underpin the intervention mechanisms, including the principles relating to counteractions. It describes:

- the existing arrangements in the NER and the rationale for these arrangements
- the issues raised in the consultation paper and stakeholders' views on these issues
- the Commission's analysis and recommendations.

5.1 Hierarchy of interventions

5.1.1 Background

Current arrangements

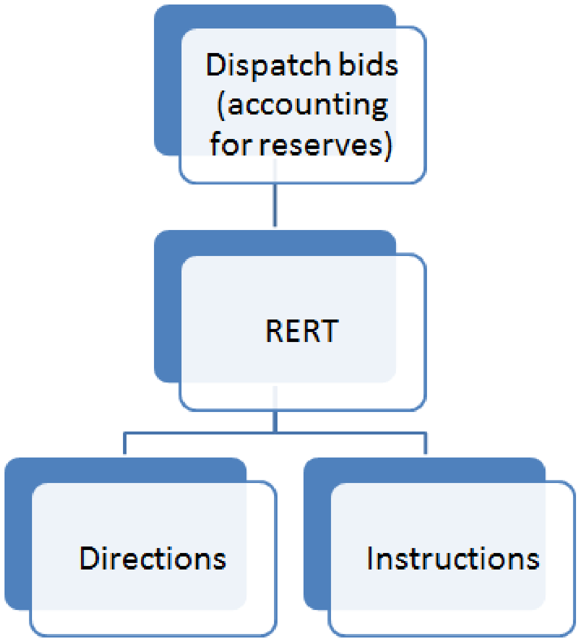
Clause 3.8.14 of the NER establishes a two-level hierarchy for the use of intervention mechanisms. In times of "supply scarcity", after dispatching all valid bids and offers required to meet demand (and accounting for market reserves), AEMO must use reasonable endeavours to first activate or dispatch[204] the Reliability and Emergency Reserve Trader (RERT or emergency reserves) and then, if necessary, issue either directions or instructions, as illustrated in figure 5.1.[205] The term "supply scarcity" is not defined in the rules and is used only in clause 3.8.14. As such, the term is to be read with its plain meaning: namely, periods during which there is a shortage or shortfall of supply.[206]

204 Unscheduled emergency reserves are said to be activated while scheduled emergency reserves are said to be dispatched. The terms are used interchangeably in this review.

205 The sequence to be followed under clause 3.8.14 is as follows: all valid dispatch bids and offers submitted by scheduled generators, semi-scheduled generators and market participants should be dispatched (including those priced at the market price cap); then, after all such bids and offers are exhausted, AEMO may exercise the RERT (i.e. dispatch/activate scheduled and unscheduled reserves in accordance with rule 3.20); and finally, if necessary, implement any corrective action under clause 4.8.5B and 4.8.9 (i.e. issue directions and clause 4.8.9 instructions).

206 The term "supply" is defined under Chapter 10 of the NER as "the delivery of electricity".

Figure 5.1: Current hierarchy of intervention mechanisms under clause 3.8.14



The NER do not specify a priority between directions (which require registered participants to take action in relation to scheduled plant and market generating units) and instructions (which require registered participants to take action other than in relation to scheduled plant and market generating units). The criterion for triggering the use of directions and instructions is the same for each mechanism: "to maintain or re-establish the power system to a secure operating state, a satisfactory operating state, or a reliable operating state".[207] In practice, however, AEMO uses directions first (for example, to manage an actual or forecast LOR2 condition) and instructions to shed load only very rarely (as a last resort to maintain system security when a LOR3 condition occurs).[208]

AEMO's obligation to follow this sequence of steps is a "reasonable endeavours" obligation. That is, AEMO will be taken to have satisfied its obligation under the clause if it can

207 Under Clause 4.8.9(a)(1) of the NER.

208 A lack of reserve (LOR) 2 condition signals a tightening of electricty supply reserves and the need for more generation to be available. An LOR3 condition signals a deficit in the supply/demand balance. At such times, load shedding may be required to keep the system secure. AEMO publicly states that it views load shedding as an 'absolute last resort' – see AEMO, *Summer 2017-2018 Operations Review*, May 2018, p. 17.

demonstrate it has taken all action that is reasonable for it to take in the circumstances to follow the sequence under clause 3.8.14. The obligation to dispatch all valid bids and offers, and to dispatch or activate reserves, is subject to "any adjustments which may be necessary to implement action under paragraph (c)"[209] and "any plant operating restrictions associated with a relevant AEMO intervention event".[210]

Rationale for the existing hierarchy

The RERT, while out of market, is a voluntary mechanism which is based on a tender process, making it more akin to a market-based mechanism than directions and instructions. Both directions and instructions are mandatory mechanisms.

Furthermore, there is an economic inefficiency associated with clause 4.8.9 instructions, as involuntary load shedding does not differentiate between customers who place a very high value on continuing supply and customers who place a lower value on continuing supply. In contrast, load curtailment under emergency reserves is on a contractual basis and therefore would reflect the participants' value of customer reliability.[211]

The hierarchy also only applies in instances of supply (i.e. the delivery of electricity) scarcity. As noted earlier, the plain meaning of the term supply scarcity applies, which would typically be during reliability events, rather than power system security events. During power system security events such as inadequate system strength, electricity supply is generally available but fault current is scarce.

5.1.2 Issues raised and stakeholders' views

In the consultation paper, the Commission sought stakeholders' views on the hierarchy of interventions, and if the existing hierarchy – i.e. RERT (also known as emergency reserves) first, then directions and/or instructions – delivers the best outcomes for consumers. The Commission queried whether prioritising emergency reserves over directions is appropriate given that both directions and RERT are interventions in the energy market and that directions may be less costly than RERT.

There were mixed views among stakeholders as to the appropriateness of the existing hierarchy; however, on balance, most stakeholders expressed support for a lowest-cost principle approach.

Snowy Hydro, Engie, AGL and the Australian Energy Council (AEC) favoured the use of the RERT ahead of directions and instructions.[212] The AEC noted that the RERT, though limited in its market-based characteristics, is closer to a market-based approach than either directions or instructions.[213]

209 Paragraph (c) refers to the implementation of "further corrective action" under clauses 4.8.5B and 4.8.9, being the implementation of directions or instructions.

210 See clauses 3.8.14(a)(1) and (2) and 3.8.14(b)(1) and (2) of the NER. An AEMO intervention event is defined as exercising the RERT and issuing a direction: chapter 10 of the NER. It does not include issuing an instruction.

211 The value of customer reliability (VCR) is an AER estimate of the value to customers of a reliable electricity supply. See https://www.aemc.gov.au/rule-changes/establishing-values-of-customer-reliability

212 Snowy Hydro, Engie, AGL: submissions to consultation paper.

213 AEC, submission to consultation paper, p. 2.

By contrast, Energy Queensland and Powershop were in favour of applying directions (and/or instructions) ahead of the RERT.[214] They considered that prioritising directions and instructions ahead of the RERT is appropriate on the basis that a small amount of load shedding should be acceptable in the context of the reliability standard. Origin also supported prioritising directions ahead of the RERT and instructions, except in instances where RERT costs have already been borne (e.g. if pre-activated at a cost).[215]

The South Australian Government stated that the direct costs of a RERT event as well as the counterfactual (i.e. the cost to consumers if load shedding had eventuated) should be taken into account.[216] It considered that changing the hierarchy to direct or instruct participants before using the RERT would seem contrary to recent changes to the RERT such as a longer procurement lead time (which dictates how far ahead of a shortfall AEMO can procure emergency reserves) and a RERT principle on costs.[217]

AEMO, Powerlink, PIAC and ERM Power considered that a prescriptive hierarchy is unlikely to deliver lowest cost outcomes to consumers in all circumstances and any hierarchy should aim to deliver the lowest cost and lowest market impact.[218]

There was considerable support[219] for applying a lowest cost principle to the choice of intervention mechanism.

For example:

- Powerlink considers that the current requirement to prioritise use of the RERT ahead of directions and instructions is potentially inefficient and should be removed. AEMO should be obliged to use reasonable endeavours to minimise the cost to consumers of an intervention and use whichever mechanism or combination of mechanisms will best achieve this objective. This assessment should be based on the information reasonably available to AEMO at the time of the intervention.[220]
- Origin considers that "interventions should minimise costs to the system. With this in mind, the market operator should first look to utilise resources within the market through directions, before deploying the Reliability and Emergency Reserve Trader (RERT) or the use of instructions'".[221]
- PIAC proposed that, in determining the hierarchy of intervention mechanisms, efficiency (providing necessary system security services at least cost) should be treated as a more fundamental goal than creating or replicating a market-based outcome.[222]

214 Energy Queensland and Powershop: submissions to consultation paper.
215 Origin, submission to consultation paper, p. 2.
216 South Australian Government, submission to consultation paper, pp. 4-5.
217 Ibid.
218 AEMO, Powerlink, PIAC, ERM Power: submissions to consultation paper.
219 AEMO, Energy Queensland, Powershop, Powerlink, TasNetworks, PIAC, ERM Power, Origin, AGL and SnowyHydro: submissions to consultation paper.
220 Powerlink, submission to consultation paper, pp. 3-4.
221 Origin, submission to consultation paper, p. 1.
222 PIAC, submission to consultation paper, pp.3-4.

- AEMO's view is that an ideal hierarchy is one that maximises operational flexibility, allowing AEMO to select the option it expects will deliver security and/or reliability at the lowest cost to consumers, accounting for the risks associated with different outcomes.[223]

AGL supported the principle that AEMO interventions should aim to minimise costs and market impacts. However, it supported retaining the current priority afforded to RERT at times of supply scarcity as it considers that this hierarchy minimises costs, while giving AEMO flexibility to choose between directions and instructions.[224] This view was echoed in Snowy Hydro's submission.[225]

Stakeholder positions are summarised in the table below.

Table 5.1: **Stakeholder views on the hierarchy of intervention mechanisms**

APPROACH	STAKEHOLDERS
Preference RERT ahead of directions/instructions	Snowy Hydro, Engie, AGL, AEC (4)
Support adopting a least cost principle	AEMO, Energy Queensland, Powershop, Powerlink, TasNetworks, PIAC, ERM, SnowyHydro, AGL, Origin (10)

Source: AEMC analysis

5.1.3 Commission's analysis and conclusions

Recent developments

Until recently, interventions were not widely or commonly used by AEMO. Power system security directions have increased markedly over the past few years, primarily due to system strength issues in South Australia. Reliability directions, however, have remained rare. Only two reliability directions have been issued since 2010.[226] This is not surprising given that generators have every incentive to be generating during a reliability event, when prices are typically close to or at the market price cap, and therefore, there generally would not be many generating units available for direction. Instead, reliability interventions in the last two years have been through emergency reserves. Emergency reserves were dispatched twice in 2017-18 and twice (on two consecutive days) in 2018-19. Prior to 2017, the RERT had never been dispatched.

The Commission has recently considered a rule change request from AEMO to enhance the RERT framework. One of the changes made by the Commission in the final rule is of relevance to the question of what is the appropriate hierarchy of intervention mechanisms. The final rule introduced a new RERT principle that the average amount payable by AEMO

223 AEMO, submission to consultation paper, pp. 3-4.
224 AGL, submission to consultation paper, p. 1.
225 Snowy Hydro, submission to consultation paper, p. 4.
226 These were directions issued to Pelican Point on 9 February and 1 March 2017.

under reserve contracts for each MWh of reserves for a region should not exceed the estimated average value of customer reliability (VCR) for that region in $/MWh. The aim of this change is to manage the direct costs of the RERT, as these costs are ultimately borne by consumers.

This new RERT principle will come into effect on 26 March 2020, along with the remainder of the enhanced RERT framework. When it commences, AEMO will be expected to only use emergency reserves if they are cheaper than load shedding consumers.

Analysis - Commission's considerations

The Commission considers that the first step of the hierarchy, dispatching available bids (while accounting for reserves, as described in more detail in chapter 6), should remain the same. This is because interventions are a last resort, once the market has failed to provide adequate reserves or capacity. The first step should therefore always be to use market bids and offers first.

The Commission's analysis has focussed instead on what happens once AEMO intervenes in the market. Specifically, it has re-assessed the existing hierarchy of intervention mechanisms in light of recent developments and increasing use of interventions, which has provided new information and detail on the operation of the mechanisms, and the costs associated with them. In considering the appropriate hierarchy, the Commission has had regard to the factors described in Box 4.

BOX 4: COMMISSION'S CONSIDERATIONS

Efficiency

Efficiency in this context relates primarily to what the most optimal mechanism would be, given the nature of the energy market. For example, market participants make decisions based on financial incentives, typically up to the market price cap. Directions, however, are through compulsion, with participants being required to comply, except in some minor circumstances. RERT, on the other hand, is voluntary, while clause 4.8.9 instructions are, like directions, involuntary. The Commission understands that the existing hierarchy is primarily based on this concept.

Direct costs

Direct costs, unlike the costs associated with spot pricing and the energy market, are rarely known in advance and cannot be hedged. Therefore, the costs of interventions are generally more expensive compared to hedgeable market costs. These costs are eventually borne by consumers.

Specifically, the costs are:

- Direct RERT costs involve the contractual costs of the RERT (typically above the market price cap but below the average value of customer reliability)

- Compensation costs associated with directions. Where directed participants provide energy or market ancillary services, they are compensated based on the 90th percentile price. This is typically far lower than the market price cap. Affected participants are also compensated if they are dispatched differently due to either RERT activation or the issuance of directions.

These costs are separate from and additional to the spot prices that everyone else pays during an intervention event. These prices are typically set through intervention pricing, which is meant to preserve the scarcity signal (i.e. preserve prices at the level the market would have seen but for the intervention).

The direct costs of a clause 4.8.9 instruction for involuntary load shedding involves setting prices to the market price cap. This cost is borne by all participants.

Indirect costs

For the RERT, indirect costs include the distortionary impact that using emergency reserves has on market participants. These indirect costs to the wholesale market mean that consumers end up paying more for reliability than they otherwise would. Costs include:

- Incentivising market participants to withdraw capacity from the market to participate in RERT, at a higher cost to consumers
- Creating disincentives for market participants to invest in capacity through the market.

For directions, indirect costs may include impacts on plant reliability: for example, if frequent directions impact a generator's ability to schedule maintenance, This may lead to an increase in unplanned outages and thus impact reliability.

The indirect costs of a clause 4.8.9 instruction for involuntary load shedding involves the implied value of lost load, i.e. the value of customer reliability, which is typically above the market price cap. However, consumers are not compensated for this cost.

Practical considerations

Intervention mechanisms typically have limitations that limit their effectiveness or that should be factored into AEMO's decision making:

- Plants can only be directed by AEMO if they are physically capable of generating (e.g. they have sufficient fuel) and if they are able to synchronise in time. This is particularly true during a supply scarcity event as the units that may be available for direction would likely be offline.
- Emergency reserves have lead times as well, but also have minimum run times.
- Involuntary load shedding is generally not precise in terms of the amount shed. Furthermore, sensitive loads cannot be shed.

Analysis - relevant factors to consider

In this section, the Commission analysed the different types of mechanisms with respect to the factors discussed in the box above, in order to reach a view on how best to approach the hierarchy of intervention mechanisms.

RERT versus clause 4.8.9 instructions

The RERT represents a voluntary arrangement for out-of-market resources to generate energy or reduce demand, and so should be preferable to instructions that lead to the involuntary shedding of load, especially given the introduction of a new RERT principle to constrain costs to be less than the cost of load shedding.

The RERT is considered more efficient than instructions as only those with a VCR of less than the cost of load shedding would participate in the RERT. Load shedding, on the other hand, continues to be based on a high-level priority list set by each jurisdiction which, on the whole, does not allow for individual VCR preferences to be taken into account.

Load shedding, unlike RERT, does not entail any direct costs. However, there would be indirect costs in terms of the impact of prices being set at the market price cap for the duration of the load shedding event. Similarly, there would be implicit costs in terms of the value of lost load (i.e. the VCR). Notwithstanding the fact that individual preferences are not known when involuntary load shedding occurs, generally speaking, the average cost of lost load should be higher than the cost of RERT. This is because the introduction of the new RERT principle regarding the average cost of RERT implies that RERT would only be used if it is cheaper than load shedding. According to AEMO, the 2019 VCR amounts to $41,534/MWh.[227]

The Commission considers that the RERT should continue to be used ahead of load shedding (i.e. clause 4.8.9 instructions to TNSPs to shed load) as activating or dispatching emergency reserves before issuing an instruction to shed load can be expected to deliver efficient outcomes and minimise costs to consumers.

In terms of the RERT versus other types of clause 4.8.9 instructions (e.g. AEMO instructing a large energy user to reduce load),[228] it would still be more efficient to use RERT (as it is a voluntary mechanism with revealed preferences). However, it may not always minimise direct costs (given the cost of RERT contracts) or indirect costs (since AEMO could potentially instruct a large energy user with a low VCR to reduce load).

Consider an example where AEMO has instructed a large energy user to reduce load. The user is not entitled to any form of compensation, so there is no direct cost involved to consumers at all. The cost is limited to the energy user itself. In this instance, direct costs would have been minimised if the instruction had been issued: i.e. the direct cost of the instruction would have been zero, while the direct costs of the RERT would have been positive. Indirect costs, or the VCR, in this instance is, say $9,000/MWh. This is likely to be lower than the costs of using RERT.

227 Market notice available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf

228 The Commission understands that this tool is not typically used by AEMO. AEMO only use clause 4.8.9 instructions in practice to instruct involuntary load shedding through the network service providers.

In this instance, more flexibility may be appropriate to reflect any known VCR (to the extent that the large energy user's VCR is known). It may be preferable for AEMO to choose to instruct the large energy user through clause 4.8.9 ahead of the RERT. This was suggested in Powershop's submission, whereby it proposed a specific hierarchy which would prioritise these types of instructions over RERT.[229] In practice, however, it is unlikely that AEMO would know the energy user's VCR. In that case, RERT would still be prioritised as it would be more efficient to use RERT.

RERT versus directions

The rationale for prioritising the RERT over directions is less obvious than the rationale for exercising the RERT ahead of instructions (where the cost of the RERT is lower than the relevant VCR).

While the RERT is more efficient due to being a voluntary process, both directions and RERT are interventions in the energy market. As with holders of RERT contracts who have agreed to be activated under contracts, market participants have agreed to be participants in the NEM, fully aware that powers of direction are available to AEMO.

It is reasonable to expect that directing in-market generators or scheduled loads may deliver reliability outcomes at costs lower than those associated with dispatching out-of-market reserves. This is because, under clause 3.15.7(c) of the NER, generators who are directed to provide energy or market ancillary services are compensated for the services they provide at the 90th percentile price, which currently ranges from $113/MWh to $145/MWh across the NEM, far below expected RERT costs. However, directed participants are also able to claim for additional compensation to reflect costs incurred as a result of the direction so that they are not out of pocket. This may, though rarely does in practice, lead to higher direct costs than just the 90th percentile price.

It is unlikely that out-of-market reserve providers would deliver services under the RERT at a cost lower than this, including the additional compensation costs. By its very definition of being outside of the market, the RERT should typically cost more than the market price cap (but less than the cost of load shedding), although RERT costs in 2018-19 amounted to $10,000/MWh.[230]

In terms of indirect costs, the RERT is far more distortionary than directions. The RERT is an out-of-market intervention which runs the risk of causing investment and operational price distortions, albeit limited by the design of the mechanism. Directions, on the other hand, by definition are an "in-market" intervention as only scheduled plant and market generating units are able to be directed. The only potential exception to this would be mothballed generation, which, depending on its classification category, may continue to be directed by AEMO despite being essentially unavailable to the market.

229 Powershop, submission to consultation paper, p. 2.

230 See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf

In considering the indirect impact of directions and RERT, it is also worth considering practical considerations. It is unlikely that AEMO would have access to generating units to direct during a reliability event. Prices would typically be sufficiently high to incentivise generating units to offer capacity into the market, including at the market price cap. Generally speaking, when units are available to be directed, there are other concerns at play, such as the ability and lead time to obtain fuel.

For example, on 8 February 2017, AEMO was unable to direct Pelican Point, which was offline at the time of the reliability event, because Engie informed AEMO that it did not have gas to run the unit and, in any case, would require at least four hours[231] to be ready for direction.[232] As this was too long a lead time, AEMO instead instructed load shedding to return the power system to a secure state. Pelican Point was able to be directed the following day, to address a second reliability issue.[233]

In the above example, AEMO did not have any RERT procured so it only had directions (and instructions) available to it. However, even if the RERT has been procured, it is not without its limitations and inefficiencies. Activating RERT may involve pre-activation as well as activation costs, minimum notice periods and minimum run times. RERT, for example, often runs for longer than required, due to minimum run times in contracts. By contrast, AEMO is required to revoke a direction as soon as it is no longer needed.[234]

It may be more efficient for AEMO to consider the lead times involved in issuing directions and RERT when it chooses which tool to use - intervening at the latest possible time is preferable in order to provide the greatest possible time for the market to respond and thus avoid the need for the intervention, or for circumstances to change such that the intervention is no longer required.[235] As can be seen above, however, it is not always the case that directions are faster to implement than RERT.

In addition, AEMO may also consider whether or not RERT costs have already been borne at the time of the event. Unlike directions, RERT involves a two-stage approach whereby contracts can be entered into up to nine months (soon to be a year) in advance of the shortfall.

In its submission to the consultation paper, AEMO provided an example of how these considerations could work in practice, including how it would choose to minimise costs to consumers, taking into account factors such as the start-up time of generating units and the earliest time at which RERT contracts need to be activated and pre-activated.[236] This example

231 Engie revised its initial advice to AEMO stating that if directed the off-line unit could be available to synchronise in just under 1.5 hrs and then be at full output within 2 hrs for a 4 – 8 hrs run time.

232 Market notice available at:https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/System-Event-Report-South-Australia-8-February-2017.pdf

233 The Commission understands that ENGIE had more of a lead time for the 9 February event, with AEMO contacting generators on 8 February. Market notice available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Market_Event_Reports/2017/NEM-Event---Direction-to-SA-Generator---09-February-2017_Final.pdf

234 NER, clause 4.8.9(b)(2)

235 For example, temperatures and demand may not reach forecast levels, meaning that no direction or out-of-market reserves are required to ensure reliability.

236 AEMO, submission to consultation paper, pp. 3-4.

shows the need for flexibility in order to minimise costs for consumers. The example is set out in the box below.

BOX 5: ADDRESSING SUPPLY SCARCITY

Suppose it is expected that the NEM will experience a supply scarcity event, that a combination of fast start units and slow start units are available for direction, and that RERT is available. For simplicity, assume there are three times at which a decision to intervene could be made by AEMO:

1. The time slow-start units would need to be directed.
2. The earliest time RERT contracts would need to be activated or pre-activated.
3. The time fast-start units would need to be directed.

At time 1, if it is forecast that the impending supply scarcity can comfortably be addressed by fast-start capacity alone, then there is no need to start any slow-start units. Conversely, if it is forecast that fast start capacity will be insufficient to address the issue, then the slow-start units would be directed to provide energy. If it is forecast that fast-start capacity will be sufficient to address the issue, but only by a small amount, then AEMO would need to assess whether the likelihood and expected cost of having insufficient fast-start capacity at time 3 warrants issuing directions to slow-start plant at time 1. Directing slow-start plant at time 1 would typically be a more expensive option than directing fast-start plant at time 3. However, directing slow-start plant at time 1 allows the flexibility of fast-start units to be retained until time 3, since a choice can then be made at time 3 as to whether fast-start units need to be directed. AEMO's assessment of whether to direct slow-start units, even though they may not be needed, effectively places a value on the additional flexibility of fast-start units above slow-start units.

A similar decision is made at time 2, this time assessing whether the likelihood and expected cost of having insufficient fast start capacity at time 3 warrants activating RERT.

Source: AEMO, submission to consultation paper, pp. 3-4.

To summarise, the RERT is likely to be more costly (both in terms of direct and indirect costs) but this may not be exclusively the case if mothballed generation is regularly being directed or if the additional compensation claims exceed the costs of RERT. (The latter is considered highly unlikely based on experience to date and having regard for the prescribed list of costs that can be included in additional compensation claims per clause 3.15.7B.) In terms of practical considerations, both RERT and directions can have lead times which need to be taken into account to maximise effectiveness.

Given the uncertainty surrounding these matters, the Commission considers that flexibility would be appropriate in terms of prioritisation.

Directions versus instructions

Currently, the NER do not prescribe any priority as between these two tools, likely because they are both involuntary actions. However, based on the discussion above, directions are, in most instances, likely to minimise direct and indirect costs to consumers. The theoretical exception to this would be if the cost of additional compensation associated with directions exceeded the value of lost load. Again, this is considered highly unlikely based on experience to date and the types of costs that can be included in an additional compensation claim.

Conclusions

The above discussion suggests that flexibility is needed in order to accommodate every circumstance whereby an intervention mechanism may be needed. As there are pros and cons to each prioritisation depending on the circumstances, the Commission agrees with stakeholders who stated that prescription may not be appropriate.[237]

The Commission acknowledges Powershop's submission on a prescriptive list of priorities, which is to reflect a trade-off between perfect reliability and costs, and to reflect the principle that AEMO should avoid procuring RERT to avoid a small amount of load shedding. The Commission notes that as from March 2020, AEMO will be guided by a new RERT principle to minimise the cost of RERT so that it is less than the cost of load shedding.

The Commission considers that the aim of any hierarchy of intervention mechanisms should be to minimise costs to end consumers. The Commission therefore considers that it would be appropriate to replace the existing hierarchy with one which is based on a principle of minimising costs, as discussed below. The Commission considers that prescription may not always lead to minimisation of costs. Relying purely on the concept of efficiency (which underpins the current hierarchy and, in this context, is about the efficiency of using a mechanism that is voluntary versus one that is compulsory) may also not always lead to a least-cost outcome for consumers.

Importantly, the first step of the hierarchy would remain the same: AEMO would still be required to exhaust all in-market options by dispatching all valid bids and offers first, including bids and offers at the market price cap (accounting for reserves). The hierarchy of use principle would only apply to intervention mechanisms, i.e. AEMO would be expected to use any combination of RERT, directions and/or instructions that minimises direct and indirect costs to consumers.

5.1.4 Recommendation

The Commission recommends introducing a new principle to guide AEMO in prioritising the use of RERT, directions and clause 4.8.9 directions. The principle would reflect that prioritisation should minimise direct and indirect costs and maximise effectiveness of the intervention.

Specifically, the Commission recommends that AEMO would need to have regard to the following principles when choosing which intervention mechanism to use in times of supply scarcity:

237 AEMO, Powerlink, PIAC, ERM Power: submissions to consultation paper.

- actions taken should be those which AEMO reasonably expects to minimise direct costs to consumers of electricity
- actions taken should be those which AEMO reasonably expects to have the least distortionary effect (i.e. minimise indirect costs) on the operation of the market
- actions taken should aim to maximise effectiveness of the intervention

This would be implemented through amending clause 3.8.14 to reflect that AEMO must use its reasonable endeavours to ensure that:

- AEMO is to dispatch all valid bids and offers first (no change from status quo)
- all other actions are to be prioritised based on the above principles.

The recommendation introduces flexibility in the way that AEMO prioritises which intervention mechanism to use, in order to minimise direct and indirect costs to consumers, who ultimately bear the costs of the RERT and directions. Flexibility would minimise the risk of inefficient and expensive outcomes, while the introduction of a clear principle would promote cost minimisation.

In terms of the principles, the Commission considers that the proposed principles would allow AEMO to optimise its use of intervention mechanisms by considering direct and indirect costs, as well as the effectiveness of an intervention. For example, as described in Box 5, the decision as to which intervention mechanism to use depends somewhat on the particular event and the characteristics of the available mechanism. AEMO may have access to a slow-start or fast-start unit, emergency reserves with short or long lead times etc. The "effectiveness" principle would allow AEMO to take these practical considerations into account. In addition, AEMO would still be required to minimise direct costs (such as the RERT contractual costs, having regard to the RERT principles) and indirect costs (such as the impact on other market participants). These requirements would reflect the existing reasonable endeavours provision in clause 3.8.14 of the NER.

The Commission acknowledges that, during a reliability event, most if not all generators will typically participate in the market voluntarily and therefore will not be available to direct. However, the Commission recognises that there can also be instances (such as February and March 2017) where units remain available to direct. The proposed change to clause 3.8.14 will mean that, in such circumstances, the current prescriptive hierarchy will not result in unnecessarily high costs being passed through to consumers, contrary to the NEO.

RECOMMENDATION 7: HIERARCHY OF INTERVENTION MECHANISMS

The Commission recommends introducing a new principle to guide AEMO in prioritising the use of RERT, directions and instructions. The principle would reflect that prioritisation should minimise direct and indirect costs and maximise effectiveness of the intervention.

Specifically, the Commission recommends that AEMO would need to have regard to the following principles when choosing which intervention mechanism to use in times of supply scarcity:

- actions taken should be those which AEMO reasonably expects to minimise direct costs to consumers of electricity
- actions taken should be those which AEMO reasonably expects to have the least distortionary effect on the operation of the market (i.e. minimise indirect costs)
- actions taken should aim to maximise effectiveness of the intervention

This would be implemented through amending clause 3.8.14 to reflect that AEMO must use its reasonable endeavours to ensure that:

- AEMO is to dispatch all valid bids and offers first (no change from status quo)
- all other actions are to be prioritised based on the above principles.

The Commission recommends that AEMO submit a rule change request to facilitate this change.

5.2 Principles underpinning intervention mechanisms

Clause 3.1.4 in the NER includes a number of market design principles, the first of which is "minimisation of AEMO decision-making to allow Market Participants the greatest amount of commercial freedom to decide how they will operate in the market". This underpins the principle that intervention in the market by AEMO is to be a last resort.

There are a number of other principles that relate to the various intervention mechanisms. As discussed below, these principles and requirements typically aim to minimise the direct and indirect impact of interventions on market participants and on end consumers.

5.2.1 Background

Current arrangements - principles and requirements for RERT

AEMO's ability to determine whether to procure reserves, and its determination of the amount of those reserves, is limited by a number of requirements.[238] A number of these are also relevant to AEMO's ability to dispatch the RERT. Broadly speaking, AEMO is expected to seek to minimise market distortions, maximise the effectiveness of the RERT at least cost to consumers, and is only expected to use emergency reserves if they cost less than load shedding consumers.[239]

In particular, AEMO:

- *Is to ensure as far as reasonably practical* the number of affected participants and the effect on interconnector flows is minimised (this also applies to directions).[240]
- When procuring or dispatching the RERT must *have regard to* the following RERT principles:

238 The NER provide the high-level framework within which AEMO may procure and dispatch the RERT. Rule 3.20 of the NER.

239 Clause 3.20.2(b) of the NER.

240 Clause 3.8.1(b)(11) of the NER.

- actions taken should be those which AEMO reasonably expects, acting reasonably, to have the least distortionary effect on the operation of the market[241]
- actions taken should aim to maximise the effectiveness of reserve contracts at the least cost to end use consumers of electricity[242]
- the average amount payable by AEMO under reserve contracts for each MWh of reserves for a region should not exceed the estimated average VCR for that region.[243]

- Must have regard to the RERT guidelines which are made and published by the Reliability Panel (currently being revised by the Panel to incorporate changes made in the Commission's Enhancement to the RERT final rule).[244] These provide additional guidance with respect to AEMO taking actions that have the least distortionary effect on the market, both in relation to the short-term impact on spot prices and the long term impact on investment signals. They also guide AEMO as to the cost-effectiveness of the RERT, and factors relevant to considering the cost-effectiveness of exercising the RERT, in consultation with relevant participating jurisdictions. The RERT guidelines also provide additional information on the factors that AEMO should take into account when applying the RERT principle that the average amount payable by AEMO should not exceed the estimated average VCR.
- Can only exercise the RERT *in accordance with* the RERT procedures, which are made and published by AEMO.[245]

Current arrangements - principles and requirements for directions

The principles and requirements AEMO must follow regarding directions are set out in the NER[246] and may be augmented by guidelines issued by the Reliability Panel (though none have been published to date). As per the RERT, these principles broadly seek to limit the impact of directions and minimise cost. Some of the principles and requirements are put into effect through AEMO's system operating procedures manual. Specifically AEMO:

- *Is to ensure as far as reasonably practical* when issuing directions that the number of affected participants and the effect on interconnector flows is minimised.[247]
- *Must use its reasonable endeavours* to minimise any cost related to directions and compensation to Affected Participants and Market Customers pursuant to clause 3.12.2 and compensation to Directed Participants pursuant to clauses 3.15.7 and 3.15.7A.[248]
- *Must* observe its obligations under clause 4.3.2 concerning sensitive loads.[249]

241 Clause 3.20.2(b)(1) of the NER.
242 Clause 3.20.2(b)(2)
243 From 26 March 2020. Clause 3.20.2(b)(3) of the NER.
244 Clause 3.20.8 of the NER.
245 Clause 3.20.7(e) of the NER
246 Clause 4.8.9(b)(1) to (5) of the NER.
247 Clauses 3.8.1(b)(11) and 4.8.9(h)(3) of the NER.
248 NER, clause 4.8.9(b)(1)
249 NER, clause 4.8.9(b)(4)

- *Must* expressly notify a Directed Participant that AEMO's requirement or that of another person authorised by AEMO pursuant to clause 4.8.9(a) is a direction.[250]
- *Must* take into account any applicable guidelines issued by the Reliability Panel.[251]
- *Should* revoke a direction as soon as AEMO determines it is no longer required.[252]

Current arrangements - principles for instructions

When issuing load shedding instructions, AEMO must:

- use reasonable endeavours to implement load shedding across interconnected regions in an equitable manner as specified in the power system security standards, taking into account the power transfer capability of the relevant networks.[253]
- comply with its obligations under clauses 4.3.2(e) to (l) of the NER (which include a requirement for AEMO to maintain a set of load shedding procedures for participating jurisdictions) and Part 8 of the National Electricity Law (regarding the safety and security of the national electricity system).

5.2.2 Issues raised and stakeholders' views

There are subtle differences between the principles that constrain and guide AEMO's use of each intervention mechanism. Noting that each intervention mechanism has different characteristics, differences between the principles governing how AEMO is to apply each mechanism may be appropriate even within the broad goal of limiting the impact of interventions on the market. In the consultation paper, the Commission sought stakeholders' views on whether there may be benefit in amending the principles to promote internal consistency.

ERM and Powershop suggested there may be benefit in amending the principles, in particular applying the principle of "minimising cost to end use consumers of electricity" to directions (in addition to the RERT) to promote internal consistency.[254]

TasNetworks acknowledges that each intervention mechanism has different characteristics but considers that the principles governing their use could be harmonised. For example, the obligation on AEMO to use directions could reference end use customers in relation to minimising costs. This would bring it into line with the principle governing minimising the cost of the RERT. In turn, AEMO could apply the "reasonable endeavours" approach currently used with directions to the RERT. This would replace the current lower hurdle of simply having regard to the RERT cost principle. These changes would enhance internal consistency amongst the intervention mechanisms and provide stronger guidance to AEMO to minimise the costs of intervention and improve customer outcomes.[255]

250 NER, clause 4.8.9(b)(5)
251 NER, clause 4.8.9(b)(3)
252 NER, clause 4.8.9(b)(2)
253 NER, clause 4.8.9(i)
254 ERM Power and Powershop: submissions to consultation paper.
255 TasNetworks, Submission to consultation paper, p. 3.

PIAC stated that the intervention mechanism principles should maintain a conceptual separation between reliability and security frameworks, particularly given the existence of "dual-purpose" instruments such as the RERT. For example, treating reliability as "non-optional" might result in consumers overpaying for electricity while treating security as a market commodity may lead to unsafe outcomes.[256]

AGL noted that the principles underlying both RERT and directions include the aim of minimising the number of affected participants. AGL believes that the application of this principle will not necessarily lead to the lowest cost option being applied.[257] AEMO shared this view as discussed in section 5.3.1.

5.2.3 Commission's analysis and conclusions

The Commission considers that the principles and requirements governing the various intervention mechanisms are consistent to the extent that they need to be, with the minor differences in wording reflecting the different uses and design features of each mechanism. For example, the cost minimisation objective is present in some form in all three mechanisms. For directions, it is to minimise the cost of directions-related compensation, for the RERT, the RERT principles set out the cost requirements, while for clause 4.8.9 instructions, it relates to shedding consumers in an equitable manner.

These differences appropriately reflect the design of each intervention mechanism. The Commission also considers that the framework appropriately captures the "last resort" principle for intervention mechanisms. For example, emergency reserves can only be used if the market is expected not to meet the reliability standard, i.e. through the declaration of lack of reserve or low reserve conditions. Similarly, the hierarchy of intervention mechanisms, described in the previous section, states that during supply scarcity, the first step is to use all market options first and foremost.

The Commission acknowledges the points raised by stakeholders regarding the differences in the principles governing the various intervention mechanisms. Three stakeholders[258] suggested that the clauses could be harmonised to refer consistently to minimising costs "to end use consumers of electricity" (language which appears in the RERT provisions but not in the directions provision). The Commission considers that this change is not necessary as the cost of compensation associated with directions is passed through to market customers and ultimately consumers via the cost recovery process set out in clause 3.15.8. As such, minimising the cost of directions-related compensation by definition involves minimising costs that are passed through to consumers. Accordingly, changing the directions provision in the manner proposed may increase clarity but would not change the substance of the existing provision.

TasNetworks further suggested that the "reasonable endeavours" language used in connection with directions should also apply to the RERT.[259] The Commission notes that the

256 PIAC, submission to consultation paper, p. 2.

257 AGL, submission to consultation paper, p. 1-2.

258 TasNetworks, ERM and Powershop.

259 TasNetworks, Submission to consultation paper, p. 3.

Enhanced RERT Final Determination includes a number of new provisions designed to minimise costs associated with the RERT. As such, the Commission does not consider it necessary to further adjust the language regarding the principles to be considered by AEMO in applying the RERT.

5.3 Counteraction requirement

The Commission considers it appropriate to make one change to the provisions governing the use of intervention mechanisms. In particular, the Commission recommends removing the provisions in clause 4.8.9(h)(3) and clause 3.8.1(b)(11) relating to counteractions. These provisions require, as far as reasonably practical, that - during an AEMO intervention event - the number of affected participants and the effect on interconnector flows is minimised.[260]

Where possible, AEMO complies with this requirement by issuing counteraction instructions to selected market participants. For example, it may direct on a unit at a power station and constrain down output from another unit at the same station, or at another station owned by the same participant. This has the effect of limiting the number of affected participants but, as discussed below, may result in a single participant being paid twice for the same energy output. Where it is not possible to confine the impact of a direction to a single participant, AEMO will if practicable issue counteraction instructions to another participant in the same region. This confines the effect of the direction to a single region, thereby limiting impacts on interconnector flows.

AEMO advises that its current systems do not support automatic invocation of counteraction constraints. Therefore, counteractions must be implemented manually, and because of the intermittent output of wind farms it is difficult to manage a manual counteraction, particularly when the direction may span multiple days.[261] As a result, AEMO is not counteracting on wind and counteractions are used only rarely in connection with South Australian system strength directions (i.e. in circumstances where gas fired generators are operating above "min gen" and can be constrained down).

Where AEMO is not able to issue "manual" counteraction instructions (for example where there is no unit available within a region for counteraction), NEMDE will automatically optimise dispatch targets across the NEM to offset the impact of the direction. For example, when AEMO directs on gas fired generators in South Australia to provide system strength services and no units are available for counteraction, other generators across the NEM will automatically be constrained down to keep supply and demand in balance. This automatic optimisation process is done on a least cost basis (whereas manual counteraction by AEMO is designed to limit the number of affected participants and impacts on interconnector flows).

The consultation paper considered whether the counteraction requirement should remain or whether it is preferable to allow NEMDE to optimise dispatch at least cost.

260 An "AEMO intervention event'" encompasses both the RERT and directions. While counteraction instructions have been used in connection with directions, they have not been used in connection with the RERT. Unlike directions to generators, activation of the RERT serves to lower demand in response to which NEMDE optimises automatically and no manual counteraction is implemented by AEMO.

261 AEMC, *Investigation into intervention mechanisms and system strength in the NEM, Consultation paper,* April 2019, pp. 48-49.

5.3.1 Issues raised and stakeholder views

A number of stakeholders commented on this issue. Engie suggested that counteractions add little value and can concentrate the effect of the direction on one participant or on a shrinking pool of generators (given the issues associated with counteracting on wind described in section 4.5 of the consultation paper). Engie considers that this can increase the burden of interventions on those participants to whom AEMO issues counteraction instructions.[262] Similarly, Powershop suggested that it is prudent for NEMDE to optimise dispatch at least cost, rather than use counteractions.[263]

TasNetworks supports the use of counteractions to the extent that the number of participants affected by the intervention is minimised but recommends that counteractions be supplemented with a least-cost analysis to ensure economic impacts from interventions are minimised.[264]

ERM supports the retention of counteractions as a means to reduce distortionary impacts. It notes that the Intervention Pricing Working Group expressed support for counteractions and suggested that AEMO should consider automating them where possible, a view endorsed by ERM. ERM also notes that, where counteraction instructions are issued to generating units in the same generation portfolio as the directed units (a practice that AEMO uses where possible to comply with the requirement to minimise the number of affected participants), this can result in the one participant receiving compensation as both a directed participant and an affected participant - effectively being paid twice for the same energy output.[265]

AEMO considers that counteractions should not be retained. It notes that the obligation to counteract in clause 3.8.1(b)(11) may conflict with the requirement in clause 4.8.9(b)(1) to minimise the cost of directions. AEMO notes that counteractions are not currently used in connection with SA system strength directions but if they were, they would likely result in output from South Australian wind being reduced and thermal output from Victorian generators increasing, resulting in higher prices. AEMO also notes that counteractions are difficult to predict (a point illustrated by the examples discussed below).

Stakeholder views are summarised in the table below.

Table 5.2: **Stakeholder views on counteractions**

APPROACH	STAKEHOLDERS
Retain counteractions	TasNetworks, ERM (2)
Remove counteractions	AEMO, Powershop, Engie (3)

Source: AEMC analysis

262 Engie, Submission to consultation paper, p. 7. The Commission recognises, however, that where counteraction instructions are issued to a participant, they become eligible for affected participant compensation. See further below.

263 Powershop, Submission to consultation paper, p. 3.

264 TasNetworks, Submission to consultation paper, p. 4.

265 ERM, Submission to consultation paper, p. 5.

5.3.2 Commission's analysis and conclusions

The Commission considers that requiring AEMO to manually adjust dispatch targets in order to limit the number of affected participants and confine the impact of an intervention to a single region can increase costs compared with the alternative of allowing NEMDE to optimise targets automatically (at least cost) in the wake of an intervention event. In this way, the counteraction requirement undermines the cost minimisation objectives discussed above.

The Commission is also concerned to ensure that the requirement to minimise the number of affected participants does not inadvertently result in market participants being paid twice for the same energy, a point noted in the ERM submission. An example of this can be seen in the directions and counteraction instructions issued to Pelican Point in February and March 2017. In both cases, directions were issued to Pelican Point gas turbine (GT) 12 to synchronise and dispatch at its minimum load. Counteraction instructions were then issued to two other units at Pelican Point (GT11 and ST18) to counter the effect of the direction to GT 12.[266] This would have resulted in payment for the output from GT12 at the 90th percentile price in accordance with clause 3.15.7. Pelican Point would also have received compensation as an affected participant based on the difference between the dispatch targets of GT11 and ST18 as between the dispatch run and intervention pricing runs (per clause 3.12.2). As ERM points out, this does appear to involve paying a participant twice for the same energy output, an outcome that may not be consistent with the NEO.

The Commission notes that counteractions can be hard to predict. For example, during a system strength direction in April 2017, AEMO imposed counteractions on Ladbroke Grove and Osborne gas turbines. Notwithstanding these counteraction instructions, energy exports from South Australia to other regions increased as a result of the directions. The AEMO market event report for this direction notes:[267]

> The directions to synchronise and dispatch to technical minimum loads resulted in approximately 1,423 megawatt hours (MWh) of direction-based generation being added to the market. Under NER 3.8.1 (b)(11), AEMO must ensure that, as far as reasonably practicable, the number of participants affected by the intervention, and the resulting changes to interconnector flows are minimised.
>
> To achieve this objective, AEMO applied counteraction constraints to reduce the output of Ladbroke Grove GT unit 1 and Osborne GT, in accordance with 4.8.9 (h)(3) of the NER. Table 3 and Table 4 summarise the estimated change to dispatch outcomes resulting from this direction.
>
> Directions in one region can cause dispatch changes to other regions, despite the use of counter-action constraints to minimise this effect. In particular, these changes are driven by economic co-optimisation within the market, and by the interplay between

266 AEMO, *NEM Event - Direction to South Australia Generator - 9 February 2017*, July 2017 and AEMO, *NEM Event - Direction to South Australia Generator - 1 March 2017*, January 2018.

267 AEMO, *NEM Event – Direction 25-26 April 2017*, April 2018, p. 7.

network constraint equations across multiple regions.

Of note is that while these directions displaced local generation in South Australia, they also increased exports from the region. The increased exports, coupled with an impact on network constraints, resulted in more energy flow northward, and displacement of some generation in New South Wales and Queensland.

Table 3 Estimated changes to local generation in each region (MWh)

	QLD	NSW	VIC	SA	TAS
Without direction	210,823	199,451	163,960	38,405	22,100
Actual	210,518	198,082	164,872	37,833 + 1,423[A]	22,145
Change	-305	-1,368	+912	+851	+45

A. 1,423 MWh is the directed energy

Table 4 Estimated changes to interconnector flow between regions (MWh)

	Terranora	QNI	VIC-NSW	Heywood	Murraylink	Basslink
Without direction[A]	-3,158	-22,307	12,862	-3,251	-1,113	-12,591
Actual[B]	-3,121	-22,050	14,637	-3,991	-1,308	-12,546
Change[C]	37 MWh less to NSW	257 MWh less to NSW	1,775 MWh more to NSW	740 MWh more to VIC	195 MWh more to VIC	45 MWh less to TAS

A. Positive numbers are for flows flowing north or west, negative for flows flowing south or east.
B. Change = |Actual - Without direction|.
C. Intervention Pricing Methodology at https://www.aemo.com.au/-/media/Files/PDF/Intervention-Pricing-Methodology-October-2014.pdf.

While the theory of counteractions is that they should confine the impact of the intervention event to the relevant region, this instance shows that - despite AEMO issuing counteraction instructions - the directions resulted in increased exports and thus the payment of affected participant compensation to generators in other regions which would have been dispatched less as a result of the direction.

The Commission has considered whether removing the counteraction requirement could impact the position of SRD unit holders due to increased changes in interconnector flows relative to the situation where counteractions are used to confine the impacts of interventions to a given region. The Commission considers that SRD unit holders will not be impacted by this proposed change, for the following reasons.

In practice, AEMO rarely issues counteractions. They are generally not used in connection with system strength directions in South Australia because there are rarely scheduled generators operating at levels above their minimum loading such that they can be constrained down to offset the impact of a direction to another scheduled generation unit to come online. As discussed in chapter 4, the Commission recommends that eligibility for affected participant compensation be narrowed such that compensation is only payable to affected participants (including SRD unit holders) in respect of intervention events that trigger the use of intervention pricing (that is, in accordance with the revised regional reference node test). That is, affected participant compensation would only be payable in respect of interventions to obtain a service traded in the market (i.e. where such services are scarce, as occurs during a reliability event).

If these changes are made as proposed, SRD units holders would still be "made whole" by receiving affected participant compensation when interventions occur in response to reliability events. As noted previously, such events are rare: there have only been two reliability directions issued since 2010 and the RERT has been dispatched on just four occasions since market start (November 2017, January 2018 and on two consecutive days in January 2019).

Counteractions are not used in connection with RERT activations so removing the counteraction requirement will not impact the position of SRD unit holders with respect to RERT activations. With respect to reliability directions, the use of intervention pricing will mean that SRD unit holders are "kept whole" in any event. This is because, to determine the intervention price, the intervention pricing run excludes the effect of the direction such that the price at which the market clears will be set as if the direction had not occurred. In other words, regardless of whether counteractions are used, intervention pricing will act to keep SRD unit holders "whole".

On this basis, the Commission considers it preferable to remove the counteraction requirement and instead allow NEMDE to optimise at least cost. This will reduce costs that can arise due to manually confining the impact of an intervention to a particular participant or region.

The Commission concludes that cost minimisation is a more important objective than minimising the number of affected participants and impact on interconnector flows. Accordingly, it recommends that the current counteraction requirement should be abolished.

5.3.3 Recommendation

RECOMMENDATION 8: REMOVE COUNTERACTION REQUIREMENT

That AEMO submit a rule change request to amend clauses 4.8.9(h)(3) and clause 3.8.1(b)(11) so as to remove the current requirement to issue counteraction instructions in order to minimise, in connection with an AEMO intervention event, the number of affected participants and the impact on interconnector flows. Instead, NEMDE should be allowed to optimise dispatch targets at least cost in the wake of an intervention event.

6 SETTING PRICES DURING RERT EVENTS

BOX 6: SUMMARY

The RERT is the NEM's strategic reserve and has formed part of the reliability framework since the start of the NEM. The RERT allows AEMO to procure "standby" emergency reserves when a supply shortfall is forecast and, to date, it has typically been used when extreme heat waves are predicted. The RERT is used as a last resort to help avoid larger and more widespread blackouts from occurring. The RERT may only be used if AEMO identifies a breach or potential breach of the reliability standard, or for power system security reasons.

When the RERT is activated AEMO is required to set dispatch and ancillary service prices to the value which AEMO, in its reasonable opinion, considers would have applied had the intervention not occurred. The purpose of intervention pricing is to preserve the market scarcity signals that would have existed had the intervention not occurred. Such signals are important as they are designed to convey to stakeholders the need for investment in additional capacity.

Under the current approach, the spot price does not automatically rise to the market price cap when the RERT is activated - this will only happen if the what-if run of NEMDE yields the market price cap. As a result, it is possible for prices to remain at relatively low levels (say approximately $300 per MWh), despite AEMO having intervened to activate out-of-market generation and demand response.

This investigation has considered the appropriateness of the application of intervention pricing following activation of the RERT. The Commission has considered the option of replacing intervention pricing with an approach whereby the spot price is set to the market price cap when the RERT is activated, similar to the approach already adopted when involuntary load shedding occurs.

The Commission considers that there are significant reasons as to why it would not be appropriate to automatically apply the market price cap whenever the RERT is activated. The RERT is used to provide additional capacity to maintain reserves and, in some cases, prevent load shedding. Thus it is not activated exclusively in scenarios where a supply shortfall would have occurred.

Further, setting prices at the market price cap may not be appropriate due to the nature of the RERT. Activating the RERT may require "pre-activation" of reserves to occur in advance of when the shortfall is projected to arise. Once activated, reserve contracts may stipulate minimum run times, meaning that the duration of the intervention event may be longer than is in fact required. As a result, emergency reserves may be activated for longer than required, not just to avoid load shedding, but also longer than required to maintain market reserves.

The Commission recommends leaving the current arrangements in place so that RERT activation for reliability purposes triggers intervention pricing (subject to the regional

reference node test being changed such that it applies to both the RERT and directions).

This chapter examines, with respect to how prices are set during RERT or emergency reserves events:

- the existing arrangements in the NER and the rationale for these arrangements
- the issues raised in the consultation paper and stakeholders' views on these issues
- the Commission's analysis and recommendations.

6.1 Background

Current arrangements

Clause 3.9.3(a) of the NER provides that, in respect of a dispatch interval where an AEMO intervention event occurs, AEMO must declare that dispatch interval to be an "intervention price dispatch interval'". Currently, intervention pricing is applied automatically whenever the RERT is activated (for unscheduled reserves)[268] or dispatched (for scheduled reserves).[269] Intervention pricing aims to minimise market distortions and preserve market signals by ignoring the effect of the intervention on the demand and supply balance. It aims to set prices based on a counterfactual of how the market would have been had the intervention not occurred.

Intervention pricing is implemented by running the NEM Dispatch Engine (NEMDE) twice – once to determine dispatch targets (the "base case target run" or "dispatch run") and once to determine intervention prices for energy and market ancillary services (the "what-if run" or "intervention pricing run"). This process happens every five minutes. Generators are dispatched in accordance with the dispatch run but prices produced by that run are ignored for the purpose of setting prices. Dispatch (and spot) prices are instead determined in accordance with the what-if run, but dispatch targets produced by that run are ignored for system operation purposes.

The dispatch levels determined in the what-if run are combined with dispatch offers to calculate a clearing price that reflects the price that AEMO considers would have prevailed had the direction not been issued or RERT not been activated.

The dispatch run includes the actions taken as part of the AEMO intervention event – including the issuing of directions or the activation of the RERT, and any counteraction constraints imposed by AEMO in order to minimise the effects of the intervention.[270] The what-if run does not include the direction or RERT activation, or any counteractions implemented to reduce their flow on effects.

268 The term dispatched and activated are used interchangeably in this chapter.

269 However, , AEMO has proposed that intervention pricing not be applied when the RERT is used to address a localised issue that does not coincide with the RRN. See https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader

270 Clause 4.8.9(h)(3) of the NER.

Relevant background

Following an incident in February 2017 where the application of intervention pricing led to unexpected price outcomes, AEMO initiated a review of whether the current intervention pricing methodology is fit-for-purpose. To this end, it commissioned a report from SW Advisory and Endgame Economics to review the implementation of intervention pricing and make recommendations to address issues arising.[271]

SW Advisory and Endgame Economics recommended that, where additional capacity (or load reduction) is brought into the market to address a shortfall – either through the RERT or directions – the generation or load should be offered into the market at the market price cap.[272] They noted that this approach does not require the use of intervention pricing reruns because it preserves the price signal that would have occurred but for the intervention.

A related approach was also recommended in submissions to the *Reliability Frameworks Review* interim report with respect to the RERT. EnerNOC's submission stated that "one option the Commission could explore further is to set the spot price to the Market Price Cap for the duration of Strategic Reserves activation. This would preserve investment price signals with absolute undeniable certainty, and also put AEMO under pressure only to intervene as late as possible, and only when involuntary load shedding would otherwise be almost certainly unavoidable." This was echoed in the Energy Efficiency Council's submission.[273]

By contrast, under the current approach, the spot price does not automatically rise to the market price cap when the RERT is activated - this will only happen if the what-if run of NEMDE yields the market price cap. As a result, it is possible for prices to remain at relatively low levels, despite AEMO having intervened to activate emergency reserves.

6.2 Issues raised and stakeholders' views

The consultation paper explored whether the spot price should be set to the MPC when the RERT is activated. The Commission noted that, on the one hand, this would be a simple solution that would alleviate the need to try to simulate what would have occurred in the market had the intervention not happened. On the other hand, it may also be problematic for a number of reasons, including the cost concerns associated with lengthy periods at the MPC and the fact that the RERT may be dispatched prior to a supply shortfall.

Of the six stakeholders who commented on this issue,[274] only Powershop supported the proposal to replace the current approach (intervention pricing) with the approach of setting the spot price to the MPC when the RERT is activated.[275] Powershop considered that the RERT should be dispatched at the MPC because it provides generators a clear signal to invest, thereby minimising the need for RERT and thus lowering costs to consumers in the longer term.[276]

271 It also established the Intervention Pricing Working Group (IPWG) to review the report and consider whether changes should be made.

272 Endgame Economics and SW Advisory, *Review of Intervention Pricing*, October 2017, p. 50.

273 See EnerNOC, submission to interim report, p. 7 and Energy Efficiency Council, submission to interim report, p. 18.

274 TasNetworks, AGL, ERM, Origin, AEMO, Powershop: submissions to consultation paper.

275 Powershop, submission to consultation paper, p. 2.

AEMO noted that, broadly, the purpose of the RERT is to provide additional reserves to the market and thus it is not activated exclusively in scenarios where a supply shortfall (load shedding) would have occurred and the price would have been set to the MPC. AEMO also added that setting prices to the MPC would conflate a lack of reserves with a lack of energy and incorrectly imply the energy market should explicitly value reserves.[277]

This was echoed by ERM Power stating the RERT is usually activated to maintain system reserve levels (as opposed to reducing the impact of load shedding) so the spot price would not be expected to be at the MPC.[278] ERM Power also noted that, if the price was set to the MPC due to RERT activation, generators would be disadvantaged if they were not dispatched.[279] ERM Power suggested that if prices were set at MPC during RERT events, generators in this position would review their financial contracting risk profile and respond to minimise their risk exposure to market intervention. This in turn would reduce contracting volumes and increase costs to consumers.[280]

AGL noted that setting the spot price to MPC when the RERT is activated would strip the RERT of a significant aspect of its purpose, which is to minimise financial impact (i.e. due to load shedding, which results in the spot price being set to the MPC).[281]

Origin noted that, if this approach were adopted, the MPC would likely apply for longer than strictly necessary due to issues such as minimum RERT run times.[282] This would increase the risk of tripping the cumulative price threshold (CPT) which would then mute the desired scarcity signal.[283] Similarly, TasNetworks noted that setting the spot price to MPC when the RERT is activated is only likely to result in higher costs to consumers and has the potential to suppress the scarcity price signal if the CPT is reached (as occurred in January this year).[284]

Stakeholder views on this issue are summarised in the table below.

Table 6.1: Stakeholder views on price setting during RERT activations

APPROACH	STAKEHOLDERS
Set price to MPC when RERT activated	Powershop (1)
Retain current approach (IP when RERT activated, noting proposed change to RRN test)	TasNetworks, AGL, ERM, Origin, AEMO (5)

Source: AEMC analysis

276 Ibid.
277 AEMO, submission to consultation paper, p. 6.
278 ERM Power, submission to consultation paper, p. 6.
279 ERM Power noted that, when the RERT was dispatched in Victoria on 30 November 2017, more than 1,000 MW of generation capacity in Victoria and South Australia was available but undispatched. Ibid.
280 Ibid.
281 AGL, submission to consultation paper, p. 2.
282 Origin, submission to consultation paper, p. 2.
283 Ibid. p. 2.
284 TasNetworks, submission to consultation paper, p. 5.

6.3 Commission's analysis and conclusions

In order to assess whether or not an MPC override would be appropriate during a RERT event, the Commission first examined the RERT in the broader context of the reliability framework, how the RERT is activated and how the market has been priced, to date, during RERT events.

Market and emergency reserves

Reliability means that the power system has an adequate amount of capacity to meet consumer needs. A reliable power system therefore involves adequate investment as well as appropriate operational decisions, so that supply and demand are in balance at any particular point in time.

The core objective of the existing reliability framework in the NEM is to deliver desired reliability outcomes through market mechanisms to the largest extent possible. In a reliable power system, the expected level of supply in the market will include a buffer, known as market reserves. Expected supply will be greater than expected demand. This allows actual demand and supply to be kept in balance, even in the face of shocks to the system such as the loss of a generating unit.

In the event that the supply/demand balance tightens, spot and (over time) contract prices would rise, which will inform operational decisions and provide an incentive for entry and expansion, addressing any potential reliability problems as or before they arise.

The RERT is an existing intervention mechanism that allows AEMO to contract for additional, emergency reserves such as generation or demand response that are not otherwise available in the market. They are additional reserves because they are in addition to the buffer that is made available by the market (i.e. market reserves) as part of the usual operation of the power system. AEMO usually procures emergency reserves if market reserves fall below a prescribed level, known as the lack of reserve 2 (LOR2) level - discussed in the next section.

These additional reserves are commonly referred to as “emergency reserves” since they are used as a last resort when the market has not otherwise provided reserves to reduce the likelihood of blackouts, typically during periods when the demand/supply balance is tight, for example, a particularly hot day in summer.

How the RERT is dispatched

There are a number of steps that AEMO must take before it dispatches emergency reserves, which means that, in practice, AEMO cannot wait until the very last minute to dispatch emergency reserves.

Under the NER, AEMO must first determine the latest time for exercising the RERT, and publish a notice of any foreseeable circumstances that may require implementation of the RERT.[285] Once such time has arrived, the NER state that AEMO may dispatch reserves to ensure that the reliability of supply meets the reliability standard and, where practicable, to

285 Clause 4.8.5A and clause 4.8.5B of the NER.

maintain power system security.[286] AEMO must also take into account the Panel's RERT guidelines before dispatching the RERT.[287]

In practice, the trigger for dispatching the RERT is how AEMO operationalises the reliability standard over the short term, i.e. through the lack of reserve declaration framework. Specifically, AEMO dispatches emergency reserves following a forecast LOR2, actual LOR2 or, for very fast-responding emergency reserves, it may wait until an LOR3.

The LOR2 reserve level is calculated as follows:[288]

- As a minimum, the LOR2 reserve level is the largest identified credible contingency event, typically the loss of the largest generating unit in a region
- However, AEMO then applies a forecasting uncertainty measure (FUM) to this minimum level in order to account for forecasting uncertainty such as wind or demand forecast deviations as well as generator outages. If the FUM is larger than the largest credible contingency event, then the FUM sets the LOR2 reserve level.

In simple terms AEMO requires that, at any point in time, there be at least an LOR2 level of reserves in the market. If market reserves (i.e. the balance of demand and supply) fall below that level, AEMO may then intervene in order to boost reserve levels. LOR3, on the other hand, typically means that the market is about to run out of reserves, i.e. load shedding is imminent.

AEMO tends to dispatch emergency reserves based on a forecast LOR2, rather than waiting for an actual LOR2 or an LOR3 to occur partly due to reserves being unscheduled (for the most part) and having lead times associated with the need to be ready to be activated. Another reason for dispatching RERT based on an LOR2 is to maintain market reserves in the system. When market reserves fall below the LOR2 level, AEMO activates emergency reserves, leading to an increase in market reserves (typically due to lowered demand).

This means that, in instances where RERT is activated due to an LOR2, there will continue to be some reserves (the LOR2 level of reserves, in theory) in the market, undispatched. These reserves would then be dispatched if the LOR2 turns into an LOR3. This can occur, for example, if there is a credible contingency event during that time (such as an unplanned outage on a generating unit), if there is a sudden change in wind meaning that wind generation is greatly reduced or if demand suddenly rises sharply. The remaining reserves in the market would then be dispatched.

At that point in time, it is also likely that the flow over interconnectors would increase (due to very low reserves in the region in question), which could lead to the interconnector reaching maximum capacity. This could lead the system to become insecure. AEMO may then need to instruct load shedding in order to return the system to a secure state.

The Commission recently published a final determination which assessed the entire RERT framework. It did not make any changes to the dispatch trigger but concluded that

286 Clause 3.20.7(a) of the NER.

287 Clause 3.20.7(f) of the NER.

288 See AEMO's reserve level declaration guidelines, which are available at: https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Consultation-on-initial-version-of-Reserve-Level-Declaration-Guidelines

improvements are being made to improve the forecasting processes that underpin the trigger.[289]

RERT events in practice

The RERT is an out-of-market, last resort mechanism. As a result, emergency reserves typically have a pre-activation (getting ready to be called upon)[290] and activation lead time (getting ready to be dispatched), as well as deactivation lead times (ramping down to zero or ramping up in the case of demand response). As noted in the previous section, AEMO tends to dispatch emergency reserves based on a forecast LOR2, rather than waiting for an actual LOR2 or an LOR3 to occur.

At the time of a forecast LOR2, prices are generally forecast to be high (approaching or at MPC), for the dispatch intervals to which the LOR2 relates. However, forecast prices, and indeed actual prices, may not be high for the entirety of the RERT activation event, as shown for selected events in Box 7.

BOX 7: PRICES DURING RERT EVENTS

January 2018 event

On 19 January 2018, AEMO activated emergency reserves for six hours.

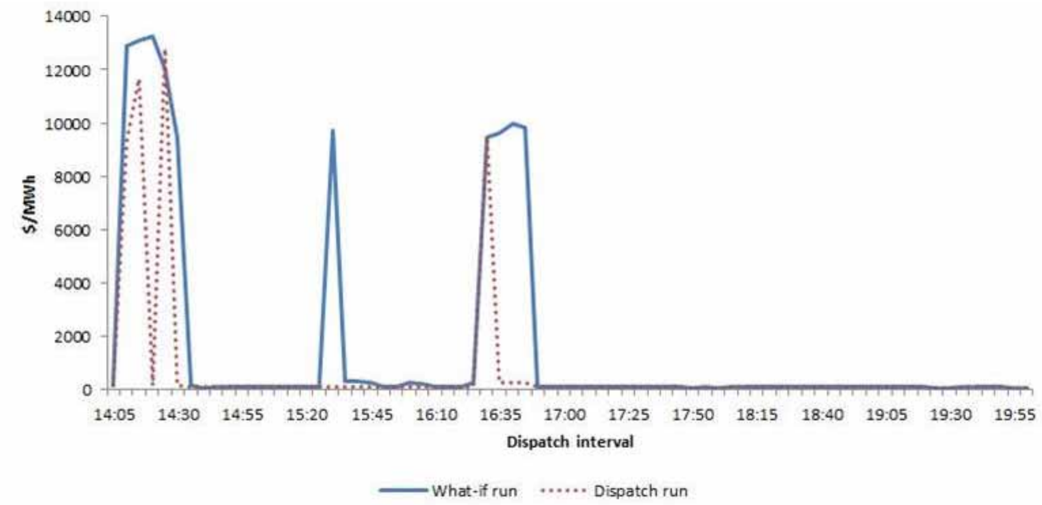
The what-if pricing run in the figure below shows how the market was priced on 19 January. These prices would be expected to be high due to the tight demand-supply balance as the what-if run ignores the effect of dispatching RERT (i.e. it assumes the demand and supply balance remained tight).

The dispatch run shows what prices would have been if intervention pricing was not being used, taking into account the effect of dispatching emergency reserves. These prices would be expected to be lower as dispatching RERT involves contracted parties reducing demand (or providing supply from out-of-market generating units). Prices were higher in the what-if run on a number of occasions but not consistently high throughout the intervention event.

289 Available at: https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

290 In January 2018, a contract was pre-activated about 20 hours prior to the forecast LOR2.

Figure 6.1: Prices on 19 January 2018 - Victoria



Source: AEMC analysis based on MMS data

It could be inferred from the chart that the emergency reserves were not needed for the entirety of the intervention event (as consistently high prices would be expected in the what-if run if the RERT had been needed for the entire six hours). However, this was likely known by AEMO, with reserves dispatched for longer than strictly required due to minimum running times specified in contracts, as well as limitations such as activation lead times. These operational complexities associated with the use of the RERT are likely unavoidable given the nature and limitations associated with out-of-market reserves, and the challenge of procuring and dispatching reserves ahead of real time, at which point better information is available.

January 2019 event

The January 2019 RERT events were different from the 2017-18 summer events in that, in addition to dispatching emergency reserves, AEMO also instructed involuntary load shedding (on both 24 January and 25 January 2019) due to LOR3 conditions. When AEMO instructs involuntary load shedding, prices in the NEM are automatically set at the MPC.

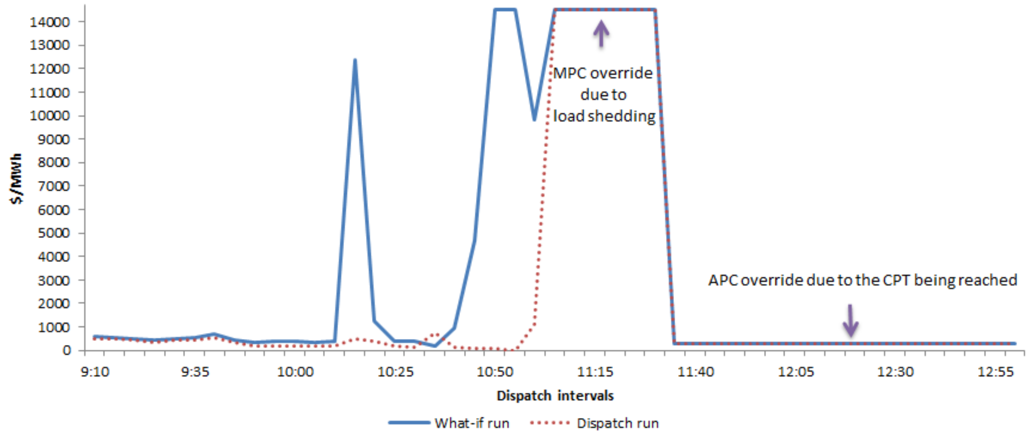
On 25 January, following sustained high prices, including prices at MPC for lengthy periods of time, the cumulative price threshold (CPT - or $216,900/MWh in 2018-19) was reached. When the CPT is reached, prices are set at the administered price cap (APC), i.e. $300/MWh, to limit market participants' exposure to sustained high prices.

The figure below shows how the market was priced on 25 January during the RERT event:

- RERT was dispatched at 09:10 NEM time (until 16:30), which means that intervention pricing was in place. Intervention prices are shown in blue.
- However, at 11:05, involuntary load shedding started, meaning that prices were overriden by the MPC.

- At 11:35, the CPT was reached. The MPC was then replaced by the APC.

Figure 6.2: Prices on 25 January 2019 - Victoria



Source: AEMC analysis based on MMS data.

Involuntary load shedding concluded at 13:50 while emergency reserves continued to be dispatched until 16:30 on the day - yet, prices remained at $300/MWh until the following morning.

Note: For the purpose of implementing intervention pricing, AEMO runs NEMDE twice when the RERT is dispatched (or when intervention pricing is implemented in connection with a direction). The what-if run sets the price as if the intervention had not occurred. The dispatch run sets the dispatch targets taking into account the intervention and any related counteraction instructions.

Why prices are not always at MPC during RERT events

In its submission to the consultation paper, AEMO stated that, broadly, the purpose of RERT is to provide additional reserves to the market and thus it is not activated exclusively in scenarios where a supply shortfall would have occurred.[291] This is consistent with the example described above whereby AEMO activates RERT based on LOR2s rather than LOR3s.

AEMO further noted that, if LOR3 is not reached, it is likely that no load shedding would have occurred even in the absence of emergency reserves - it would therefore be inappropriate to set prices to MPC in those instances.[292] The Commission agrees with AEMO that it would be inappropriate to set prices to MPC in instances whereby RERT is activated to maintain market reserves, rather than to avoid load shedding. The Commission notes that, in that instance, the intervention price would still reflect the underlying demand and supply balance and is likely to be high, even though it may not be at the MPC. This can be seen in the figures in Box 7 where there were instances of spikes in prices below the MPC.

291 AEMO, submission to consultation paper, p. 6.

292 Ibid.

Further, generally speaking, *forecast* prices are typically high when there is a *forecast* LOR2 level, to reflect the tight demand and supply balance, and signal the need for market reserves. However, actual prices in the intervention run may not be as high as forecast, due to forecasting uncertainty. For example, if actual demand is far lower than forecast demand, this would mean that there was no need for emergency reserves to avoid load shedding. In that instance, it would be inappropriate to signal scarcity by setting prices at the MPC.

Similarly, setting prices at the MPC may not be appropriate due to the nature of the RERT. Activating the RERT may require "pre-activation" of reserves to occur in advance of when the shortfall is projected to arise. Further, once activated, reserve contracts may stipulate minimum run times, meaning that the duration of the intervention event may be longer than is in fact required. As a result, emergency reserves may be activated for longer than required, not just to avoid load shedding, but also longer than required to maintain market reserves.

A clear example of this occurred on 19 January 2018 in Victoria - as shown in the figure above, prices remained low after 17:00 and the last RERT contract was de-activated at 20:00 due to minimum run times, long after the event was over. It would be inappropriate for prices to be at the MPC once the reliability event is over even if RERT continues to be in place. There would be no need to signal scarcity. The intervention price reflected the underlying supply and demand balance, and the market price was set accordingly. This price, even in the absence of the intervention, would likely be relatively low.[293]

In a similar vein, the nature of the RERT also means that it tends to be activated for a block of time (say six hours), rather than in five-minute intervals. LOR2 gaps can occur in a few dispatch intervals over the six-hour block. Yet, RERT would be activated for the full six hours. In practice, scarcity would only need to be signalled for the relevant dispatch (or trading) intervals, rather than for the entire six-hour block.

Conclusions

The Commission examined two options for pricing the market during RERT events:

- an MPC override, whereby prices would be automatically set at the MPC during a RERT event, similar to the MPC override that occurs when there is load shedding
- the status quo, i.e. using intervention pricing.

The Commission considers that the MPC override would not be appropriate given the practicalities of how the reliability framework is operationalised in the NEM, such as:

- RERT is often activated to maintain market reserves, and not necessarily to avoid load shedding.
- RERT activation is also subject to forecasting deviations, meaning that it may be activated in anticipation of a forecast gap that does not eventuate.
- RERT is often activated before it is required (either to maintain reserves or to avoid load shedding) and for longer than required.
- RERT is often activated for a block of time, rather than for specific dispatch intervals.

293 There would still be a difference between the what-if and the dispatch run to account for the impact of the intervention. The scale in the figure above does not accurately reflect these differences.

- Setting the spot price to the MPC increases the risk of tripping the CPT which would then mute the desired scarcity signal (as happened in January 2019), shown above.

Unnecessarily signalling scarcity is inefficient and costly. Setting prices at the MPC beyond the point when a reliability event ends or to signal scarcity when it does not exist would have significant cost implications for consumers, through higher electricity bills, and without delivering any additional reliability benefits.

Furthermore, if prices are set at the MPC for extended periods, the CPT would be reached. The CPT imposes a limit on sustained high prices in the wholesale market. The CPT is reached if the sum of spot prices for the previous week exceeds a specific value.[294] Generally speaking, the MPC would only need to apply for 15 trading intervals over a rolling one-week period for the CPT to be reached, including for example if the MPC is in place for 7.5 hours in a row.[295] The administered price cap (APC) applies when the CPT is exceeded. Prices are capped at $300/MWh, with the cap remaining in place until the sum of prices over the past week (on a rolling basis) amounts to less than the CPT.

This scenario occurred in January 2019, as shown in Figure 6.2 when the CPT was reached after sustained high prices, including the application of the MPC override due to load shedding. The Commission understands, through submissions to the draft determination on the *Enhancement to the RERT* rule change,[296] that the $300/MWh cap being in place led to demand response providers withdrawing from the market, due to low prices.

While the APC is outside of the scope of this review, the Commission is cognisant of the impacts of having a low price cap in place during a reliability event. The Reliability Panel is expected to examine this issue as part of its next review of the reliability standard and settings. On the one hand, the APC did what it was intended to do: shielding consumers from sustained periods of high prices. On the other hand, the APC started at a time when the scarcity signal needed to be preserved (i.e. the market had run out of reserves and load shedding was occurring), potentially worsening the reliability issue. This is different from a situation whereby the APC is imposed after a week of dispersed high prices unlinked to a specific event. Setting prices at the MPC during RERT events would further exacerbate this issue.

In addition, setting prices at MPC during RERT events may reduce transparency relative to the current situation where intervention pricing is applied when the RERT is activated. This is because there would be no need to undertake both the dispatch run and what-if run in order to set prices, and thus no means to consider what the price would have been had the RERT not been activated. This reduces visibility with respect to the amount of RERT required to avoid load shedding.[297]

294 $221,100 in 2019-20.

295 It could be reached before then if prices had been high prior to the MPC being in place.

296 Meridian and Energy Australia: submissions to draft determination, Enhancement to the RERT rule change.

297 The Commission notes that the Reliability Panel is currently examining the definition of unserved energy, which includes discussion of calculating RERT amounts that would have avoided load shedding. Available at: https://www.aemc.gov.au/market-reviews-advice/definition-unserved-energy

Finally, the discussion above largely assumes that the RERT is used to maintain reliability. While the RERT cannot be procured in response to a system security issue, it can - if it has already been procured in response to a projected reliability shortfall - be used where practicable to address a system security issue. The Commission concludes that in such cases, setting the spot price to the MPC would not be appropriate - there would be no underlying scarcity.

Recommendation

The Commission recommends leaving the current arrangements in place so that RERT activation/dispatch for reliability purposes triggers intervention pricing.

However, in accordance with the Commission's draft determination on Application of the RRN test to the RERT, intervention pricing would not apply if the RERT was activated to provide a service which is not traded in the market. [298] As discussed in chapter 3, this would have the effect of "turning off" intervention pricing where there is no scarcity of a market-traded commodity. This is on the basis that, in such cases, there is no relevant price signal to preserve and using intervention pricing can cause rather than reduce market distortion. Similarly, there would be no utility in setting prices to the MPC in such cases. Doing so would exacerbate cost impacts on consumers and distortionary effects on investment signals.

To be clear, the Commission does not recommend setting prices at the market price cap during any RERT activation, be it for reliability or security purposes, as:

- the RERT may be activated to maintain adequate market reserves, not to prevent load shedding – in this case pricing at the MPC is not appropriate
- the RERT may be activated ahead of time, based on forecasts, which means that applying the MPC may be subject to forecasting uncertainty
- the RERT is not a "perfect" mechanism and is subject to minimum lead times and run times which mean that the MPC would likely apply for longer than strictly necessary
- doing so would increase the risk of tripping the CPT which would then mute the desired scarcity signal (as happened in January 2019, shown above).

RECOMMENDATION 9: SETTING PRICES DURING RERT EVENTS

The Commission does not recommend setting the spot price to the market price cap when the RERT is activated. Where the RERT is activated in response to scarcity of supply, prices should continue to be set based on intervention pricing.

As discussed in chapter 3, the Commission has determined that where the RERT is activated to obtain a service that is not traded in the market, intervention pricing will not apply and prices will bet set by NEMDE in the usual manner.

298 The AEMO rule change request and draft determination are available at: https://www.aemc.gov.au/rule-changes/application-regional-reference-node-test-reliability-and-emergency-reserve-trader

7 MANDATORY RESTRICTIONS FRAMEWORK

BOX 8: SUMMARY

Mandatory restrictions on the use of electricity may be imposed by a jurisdiction as a means of controlling demand and averting a situation where there is insufficient generation capacity to meet demand, particularly in situations where mandatory load shedding is or would otherwise be necessary. These restrictions may come into effect during periods of extreme demand or instances where a sudden decrease in available capacity occurs.

When restrictions are imposed on a region, electricity users are requested to reduce demand (and large electricity users may be required to reduce demand). AEMO is then required to call for sufficient capacity contracts ("restriction offers") equal to the estimated reduction in demand due to the restrictions. If demand is higher than anticipated and this contracted capacity has to be dispatched, it is dispatched at the market price cap (MPC). This creates a risk of tripping the cumulative price threshold and triggering an administered price period, thereby muting scarcity signals and demand response incentives at a time when they are most needed.

The rationale for introducing the mandatory restrictions framework was to preserve price signals during a period where demand is reduced as a result of restrictions and provide an incentive for generators to invest and increase supply. However, the application of mandatory restrictions may result in outcomes that would leave market customers worse off than if restrictions and related pricing procedures had not been imposed. For example, errors in the estimation of demand reduction due to restrictions may result in price outcomes that are on average higher than would have occurred had the estimate of demand reduction due to restrictions been accurate. Alternatively, market customers (and their consumers) may have to bear AEMO's costs of contracting generation capacity even if it is not ultimately required due to the level of demand response achieved in response to restrictions.

The Commission considers that the mandatory restrictions framework should be removed from the NER. The Commission notes that the market context has significantly changed since the mandatory restrictions provisions were included in 2001 - for example, there is significantly more technical and institutional capacity to reduce demand in response to high prices and greater willingness to use the reliability and emergency reserve trader to address anticipated shortfalls.

The mandatory restrictions framework has not been used to date and, given the difficulty in accurately estimating the level of demand reduction that will be achieved by restrictions, the Commission considers that the risk of unintended pricing outcomes is high. The Commission notes that jurisdictions will still have the ability under state-based legislation to impose mandatory restrictions. However, the Commission considers it preferable - if restrictions are imposed - to allow the market to operate as normal, enabling participants to respond efficiently in real time to price signals that accurately reflect the supply demand balance. The alternative approach considered in the consultation paper (i.e. using intervention pricing in place of the current capacity contracting system) is not supported on the basis that it is subject to many of the same forecasting challenges as the current mandatory restrictions framework. Finally, the ongoing allocation of AEMO resources to maintain this framework is not justifiable.

Recommendation: AEMO to submit a rule change request to remove the mandatory restrictions framework from the NER.

This chapter examines, with respect to the design and operation of the mandatory restrictions framework:

- the existing arrangements in the NER and the rationale for these arrangements
- the issues raised in the consultation paper
- the Commission's analysis and recommendations.

7.1 Background

Rationale for mandatory restrictions

In late January and early February 2000, the supply of electricity in Victoria, NSW and South Australia was disrupted by a combination of technical issues and industrial action. On 23 January 2000, units at Bayswater, Mount Piper and Torrens Island power stations tripped in quick succession leading to a loss of over 1,400 MW or 10 per cent of demand.[299] In the first few weeks of February, the impact of industrial action at Yallourn was exacerbated by record high demand. As a result, demand exceeded supply in Victoria and South Australia and significant load shedding occurred in each region. On 4 February, Victoria imposed demand restrictions which continued until 10 February 2000.[300]

When restrictions are imposed by a jurisdiction on a region, electricity users are requested to reduce demand (and large electricity users may be required to reduce demand). This reduces the quantity of electricity traded, the spot price, and thus the revenue earned by generators. The level of demand response that will be achieved by restrictions is difficult to estimate and the actual response by consumers may be more or less than is necessary. The reduction will not count towards the relevant jurisdiction’s share of inter-regional load shedding and, perversely, would reduce the spot price at the height of a shortfall.[301] This is in contrast to the approach whereby the spot price is set to the market price cap if involuntary load shedding occurs.

In July 2000, the National Electricity Code Administrator (NECA – the predecessor of the AEMC) investigated integrating demand restrictions into the market in order to preserve price

299 NECA, Investigation into the Market’s Performance in Extreme Conditions, July 2000
300 ibid.
301 ibid.

signals and ensure that market prices during such periods provide an appropriate incentive for new investment in generation and demand side management schemes.[302] This investigation also recommended changes to the market pricing provisions in order to clarify how prices should be set during extreme events.

Following the investigation, new provisions under Rule 3.12A were added to the NER in 2001 to incorporate mandatory restrictions in the centralised dispatch and pricing process.

Mandatory restrictions are a market intervention mechanism, whereby restrictions are imposed by a jurisdiction[303] under state-based legislation and the pricing mechanism is applied by AEMO in instances where a supply demand imbalance is forecast. The NER defines mandatory restrictions as "restrictions imposed by a participating jurisdiction, by a relevant law, other than the rules, on the use of electricity in a region".

Mandatory restrictions on the use of electricity may be imposed by a jurisdiction as a means of controlling demand and averting a situation where there is insufficient generation capacity to meet demand, particularly in situations where mandatory load shedding is or would otherwise be necessary. These restrictions may come into effect during periods of extreme demand or instances where a sudden decrease in available capacity occurs.

Current arrangements

An example of a relevant state law is the Electricity Supply Act 1995 (NSW). Amendments were made to that Act following the February 2017 heatwave during which the NSW Government publicly encouraged customers to reduce demand.[304] These amendments were designed to provide the NSW Government with the streamlined and updated tools needed to take action in the management of an electricity supply emergency. The provisions recognise that AEMO has primary responsibility for managing electricity emergencies but are designed to support AEMO. For example, they empower the Minister to direct persons or corporations who are not registered participants in the NEM, thus assisting AEMO by undertaking actions that are beyond AEMO's remit.[305]

The Electricity Supply Act amendments outline when directions can be issued and the terms by which they can be varied and revoked. Section 94B(2) provides that "electricity supply emergency directions may be given (…) to restrict the use of electricity in order to reduce demand". Directions may require large users of electricity to wholly or partly turn off or shut down any plant or equipment for a specified period of time: s94B(2)(b). Failure to comply

302 ibid.

303 The National Electricity Market – Memorandum of Understanding on the Use of Emergency Powers 2015 defines jurisdictions as NSW, VIC, QLD, SA, ACT and TAS or any other party who becomes party to this memorandum.

304 AEMO, System Event Report New South Wales, 10 February 2017

305 The second reading speech for the Electricity Supply Amendment (Emergency Management) Bill 2017 notes that "in the majority of situations, the Australian Energy Market Operator can take the necessary action and does not require intervention from the New South Wales Minister. However, if the Australian Energy Market Operator is not able to do what is needed because of limits on its powers, AEMO may require assistance from within New South Wales. Some examples where a New South Wales energy Minister may be asked to assist include: where directions must be given to persons other than registered participants in the national electricity market and AEMO requests that New South Wales declare an electricity supply emergency and exercise its local emergency powers; or where a power supply disruption is likely to have an extended duration requiring mandatory restrictions for the broader community, including exemptions for vulnerable consumers. The powers needed by the New SouthWales Minister for energy are not likely to be used frequently, but when they are needed, they must operate quickly and effectively." Available at https://www.parliament.nsw.gov.au/bill/files/3455/2R%20Electricity%20Supply%20Amdt.pdf

with a direction is an offence. The state is not liable to pay compensation for any loss resulting from the use of electricity supply emergency directions: s179A(1B).

Rule 3.12A of the NER outlines how mandatory restrictions are to be implemented by AEMO. It includes provisions relating to restriction offers, mandatory restrictions schedule, acquisition of capacity, rebid of capacity, dispatch of restriction offers, pricing during a restriction price trading interval, determination of funding restriction shortfalls, cancellation of a mandatory restriction period, and review by the AEMC. The provisions are designed to integrate mandatory restrictions into the market to ensure the delivery of a reliable and secure power supply. This is achieved through capacity contracting which is used to preserve scarcity price signals when demand falls in response to the imposition of a mandatory restriction.[306]

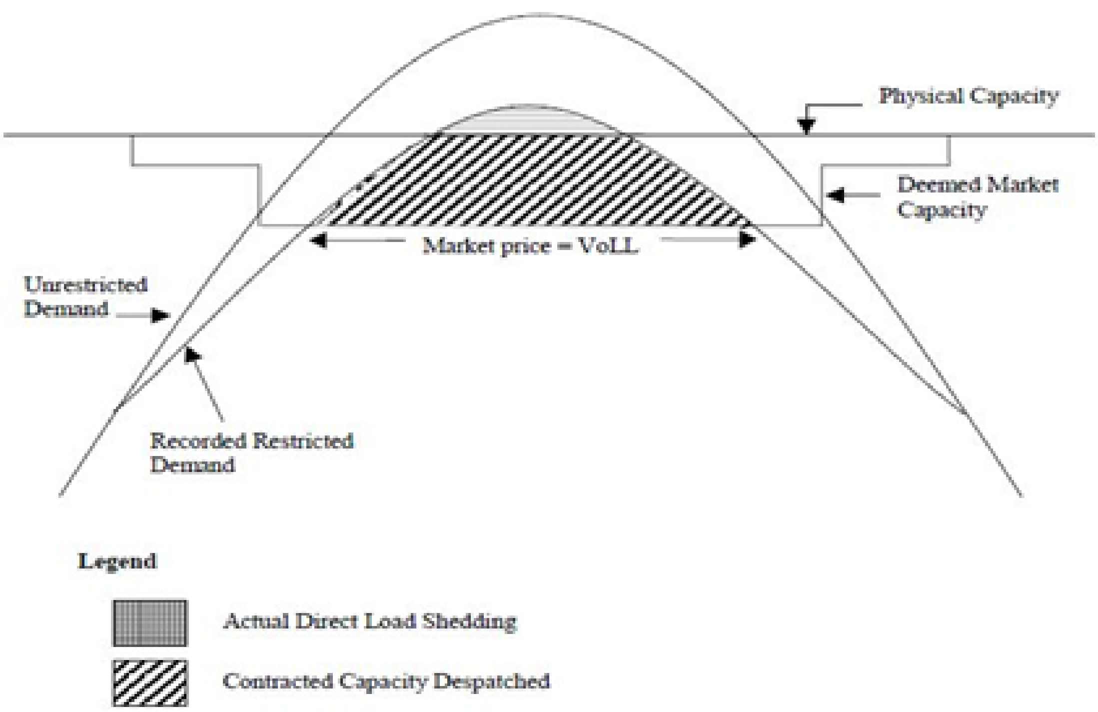
When restrictions are declared upon electricity usage in a region, AEMO will be required to call for sufficient capacity contracts ("restriction offers") equal to the estimated reduction in demand due to the restrictions. The estimated restricted demand for each trading interval of the upcoming trading day subject to a mandatory restriction is provided by the *mandatory restriction schedule,* as prepared by AEMO and approved by the participating jurisdiction. The *mandatory restriction schedule* is to be reviewed and, if appropriate, amended by AEMO any time that the forecast restricted demand differs from the actual regional demand by at least 50-150MW (dependent on the region). Following each amended schedule, AEMO contracts for further capacity or terminates excess capacity contracts as is required. By this means, the quantity of generation capacity can more accurately reflect the actual demand reduction that follows a mandatory restriction and thereby limit customer exposure to excessively high spot prices or contract costs, while preserving efficient scarcity price signals.

Capacity can be offered by any participant (generators and market network service providers) already presenting to the market. The scheduled capacity, equivalent to the estimated reduction in demand due to the restrictions, would be contracted to AEMO through price-quantity bids and withdrawn from the market for pricing purposes for the duration of the restrictions as shown in figure 7.1 below. This scheduled capacity would remain available for dispatch at the market price cap once all other options, including scheduled loads, have been exhausted. AEMO is entitled to all spot market revenue from dispatch of these contracted capacities and uses this revenue to cover the costs of the contracts. Any remaining difference between the costs of the capacity contracts and the revenue from dispatching these contracts at the market price cap is called the *restriction amount shortfall.* This is recovered from market customers proportional to their share of energy demand during the mandatory restriction period.

This is designed to avoid the outcomes seen in early 2000, where anecdotal reports indicate that demand response was so significant during this period that the resulting fall in the spot price led to generation being exported from Victoria to South Australia and NSW, which had not implemented restrictions.

306 Australian Customer and Competition Commission, *Pricing under Extreme Conditions: Final Determination*, September 2001

Figure 7.1: Integrating restrictions into the market



Source: NECA, Investigation into the Market's Performance in Extreme Conditions, July 2000. Clause 3.12A.1(a) of the NER requires AEMO to develop a "mandatory restrictions trading system" in accordance with the Rules consultation procedures. The trading system must include procedures for the acquisition of capacity, restriction offer, standard terms and conditions, procedures for funding restriction shortfalls and procedures for rebidding and dispatch of capacity.

AEMO has developed a Mandatory Restriction Offers Procedure (2015) which explains the restriction offer process and outlines the arrangements for dispatching mandatory restriction offers when restrictions are declared in a jurisdiction.[307]

7.2 Issues arising with respect to mandatory restrictions

Mandatory restrictions have been designed to minimise the extent of involuntary load shedding and improve the arrangements for determining reserve thresholds consistent with the standards set by the AEMC Reliability Panel.

307 AEMO, Mandatory Restriction Offers Procedure SO_OP_3713, November 2015

The concept of integrating restrictions into the market to preserve scarcity price signals and balance supply and demand under extreme market conditions was supported in principle by stakeholder submissions during the proposed code change.[308] However, a number of stakeholders expressed concern about estimating demand reduction, unmanageable risk created for market customers, recovery of costs based on beneficiaries in mandatory restriction periods, gaming by customers, and jurisdictional intervention.

Submissions identified that the challenge of accurately estimating the likely impact of restrictions would distort outcomes and not achieve the intended objective of preserving efficient investment signals.[309] An over estimation of the demand reduction due to restrictions would cause a situation where the spot price is set at the MPC, potentially for an extended period which could have a major impact on market customers, particularly those who are not fully hedged.

While an extended period of prices at the MPC will eventually exceed the cumulative price threshold and trigger an administered price period (effectively capping retailers' market risk), risk exposure in the interim period could nonetheless be significant. Triggering an administered price period can also be expected to discourage demand response at a time when it is most needed. The Australian Competition and Consumer Commission (ACCC) considered that contract prices could rise as there are incentives for generators to become less hedged and retailers to become more hedged.[310]

The ACCC considered the above issues in its final determination. It concluded that the proposed amendments to the Code were likely to result in a benefit to the public which outweighed the potential detriment from any lessening of competition that would result if the proposed conduct or arrangements were made or engaged in.[311]

Mandatory restriction pricing arrangements have not been applied in any of the jurisdictions to date. However, the ageing generation fleet and the increasing frequency and intensity of extreme weather events may lead to situations where jurisdictions need to reduce demand when a projected shortfall is not expected to be met through market responses and/or the RERT, and the extent of involuntary load shedding is considered unacceptable from a jurisdictional perspective. On the other hand, the market has changed significantly since rule 3.12A was included in the NER, particularly with respect to technical and institutional capacity to undertake demand response, and increased reliance on the reliability and emergency reserve trader (RERT) in response to anticipated shortfalls. As such, relevant questions arise as to whether the mandatory restrictions framework should be retained, and if so, whether the framework should be amended.

The rationale for introducing the mandatory restrictions framework was to preserve price signals during a period where demand is reduced as a result of restrictions and provide an incentive for generators to invest and increase supply. However, the application of mandatory

308 ACCC Determination, Amendments to the National Electricity Code, September 2001, available at https://www.accc.gov.au/system/files/public-registers/documents/D03%2B38144.pdf

309 ibid.

310 ibid.

311 ibid.

restrictions may result in outcomes that would leave market customers worse off than if generator contracting and pricing procedures had not been imposed. Errors in the estimation of demand reduction due to restrictions may result in price outcomes that are on average higher than would have occurred had the estimate of demand reduction due to restrictions been accurate.

An over-estimation of demand reduction following a mandatory restriction would cause too much capacity to be contracted, resulting in high contract costs for market customers and greater exposure to market price cap events. For example, if AEMO estimates 1000 MW of demand reduction but actual demand reduction is only 800 MW, customers would be exposed to the market price cap at lower demand levels than necessary to reflect the scarcity of supply. Effectively, the amount of available supply as seen by the market is reduced by 200MW more than would be the case if generator contracting was not in place. That is, the mechanism, in this case, would result in prices that are higher than the supply scarcity would reflect if not for the mandatory restrictions, imposing greater spot market costs on market customers as well as unnecessary excess contract costs.

Alternatively, an under-estimation of demand reduction following a mandatory restriction would cause market customers (and their consumers) to bear AEMO's costs of contracting generation capacity even if it is not ultimately dispatched due to the level of demand response achieved preventing demand from nearing the limits of supply capacity. For example, if AEMO estimates 1000 MW of demand reduction but actual demand reduction is 1200 MW, the market sees more supply available than would be the case if generator contracting was not in place. In this case, if the amount of load shedding expected without mandatory restrictions was less than 200MW, the contracted capacity would not be dispatched at all. Hence, spot prices would not reflect the scarcity of supply, imposing the contractual costs of mandatory restrictions on consumers without achieving the objectives of the framework, namely to preserve scarcity price signals when mandatory restrictions are imposed.

These examples illustrate the asymmetrical outcomes of the framework whereby its objective, to preserve scarcity price signals, is only achieved if demand reduction is forecast accurately or is under-estimated (in which case scarcity price signals are exaggerated). This risks imposing excessive contractual and market costs on customers who are providing the demand reduction service to preserve power system reliability.

7.3 Stakeholder views

The consultation paper asked whether the mandatory restrictions framework should be retained and whether it should be amended in any way. For example, would it be preferable to use intervention pricing (as used for the RERT and directions) as the means to preserve scarcity price signals rather than require AEMO to contract for capacity (which, if dispatched, is priced at the MPC) independently of the normal dispatch process.

Of the submissions received, only around half included comments on the mandatory restriction provisions. The mandatory restrictions framework is universally recognised by stakeholders as a significant intervention only to be used in times of extreme forecast load shedding.

The AEC recognised that mandatory restrictions are inherently distortionary and preferably avoided. However, it did recognise that state governments will reserve this power, and may exercise it should an extended period of shortfall develop. The AEC supported reviewing the framework and investigating whether its complex pricing mechanism could be replaced with a more familiar intervention pricing technique. If this proves too complex, the AEC suggests that, on balance, removal of the framework implies less market risk than retention in its current form.[312]

Similarly, TasNetworks suggests intervention pricing could provide an alternative, more transparent, less blunt and easier to implement mechanism than mandatory restriction pricing. ERM, however, notes that a major benefit of the current provisions is that, where mandatory restrictions are applied in a region, the impact of the "intervention" is to an extent confined to that region. ERM considers that replacing these provisions with intervention pricing provisions would result in market distortion with the impact of the mandatory restrictions being transferred to other regions of the NEM.[313]

Powershop notes that, given the inherent uncertainty associated with the forecasts that underpin this type of intervention, mandatory restrictions may result in the MPC being applied for excessive periods of time. However, Powershop suggests that the mechanism should remain available for the circumstances where AEMO and the relevant jurisdiction are unable to minimise bulk load shedding through directions, instructions, or the procurement of the RERT.[314]

Engie notes that steps taken by market participants, AEMO and the AEMC in recent years to cultivate additional demand side resources through contracts and rule changes means the likelihood of any jurisdiction needing to implement such restrictions (rather than elicit a voluntary response) has receded.[315]

AEMO and Snowy Hydro suggest that the framework should be removed. Snowy Hydro notes that the spot market (supported by the RERT and directions) can enable participants on both the supply and demand side to respond to price signals, even in extreme conditions.[316] AEMO notes that the framework has not been used since its inclusion in 2001 and notes that Victoria, South Australia and NSW have provided funding in support of RERT, suggesting this is a preferable means of managing supply shortfalls.[317]

Stakeholder views are summarised in the table below.

312 AEC, Submission to consultation paper, p. 3.
313 TasNetworks, Submission to consultation paper, p. 4.
314 Powershop, Submission to consultation paper, p. 3.
315 Engie, Submission to consultation paper, p. 7.
316 Snowy Hydro, Submission to consultation paper, p. 6.
317 AEMO, Submission to consultation paper, p. 4.

Table 7.1: Stakeholder views on mandatory restrictions

APPROACH	STAKEHOLDERS
Retain mandatory restrictions	Powershop, ERM (2)
Retain mandatory restrictions but consider IP option	PIAC, TasNetworks, AEC (3)
Remove mandatory restrictions	AEMO, SnowyHydro

Source: AEMC analysis

7.4 The Commission's analysis and conclusions

On further reflection, the Commission considers that the alternative of using intervention pricing to preserve investment price signals is problematic in the context of mandatory restrictions. To use intervention pricing, AEMO would need to develop a counterfactual for the purpose of the intervention pricing run that reasonably estimates what demand would have been but for the restrictions. This is inherently uncertain and thus this approach is subject to the same difficulties as the existing mandatory restriction provisions. For this reason, the Commission no longer supports amending the provisions in this way.

The Commission considers that the mandatory restriction framework should be removed.

The Commission notes that, even if the mandatory restrictions pricing framework is removed from the NER, jurisdictions will retain the ability to impose mandatory restrictions under state legislation.[318] The Commission also notes that investors do not make investment decisions on the basis of exceptional events such as would prompt the imposition of mandatory restrictions. Given this, the rationale of preserving investment signals should not be a major factor in determining whether to keep or remove the provisions.

The mandatory restrictions framework has not been used to date and, given the difficulty in accurately estimating the level of demand reduction that will be achieved by restrictions, the Commission considers that the risk of unintended pricing outcomes is high. For example, if demand is higher than anticipated and contracted generation capacity has to be dispatched, it is dispatched at the market price cap (MPC). This creates a risk of tripping the cumulative price threshold and triggering an administered price period, thereby muting scarcity signals and demand response incentives at a time when they are most needed.

The Commission considers it preferable - if restrictions are imposed - to allow the market to operate as normal, enabling participants to respond efficiently in real time to price signals that accurately reflect the supply demand balance. If, even after restrictions have been imposed, the supply demand balance remains tight and spot prices high, then consumers will have an incentive to reduce demand further. The reverse is also true, leading to more efficient decisions by market participants.

318 The provisions in the NER relate only to dispatch and pricing processes. They do not underpin the ability of states to impose restrictions if required in extreme circumstances.

Retaining mandatory restrictions in the NER will require AEMO to continually allocate internal resources to maintain the pricing framework and ensure that it incorporates the latest market developments. This results in regular training and incidental upgrades to the system. The Commission considers the ongoing allocation of AEMO resources to maintain this framework is not justifiable.

7.5 Recommendations

The Commission recommends that the mandatory restrictions framework should be removed as:

- it has never been used, is very complex and unlikely to deliver desired results
- adjusting the framework as proposed in the consultation paper, by using intervention pricing to preserve scarcity signals, would be unlikely to solve the problems associated with the existing framework. This is because the application of intervention pricing would require AEMO to estimate what demand would have been absent the restrictions and there is no reliable way to do this accurately
- removing the mandatory restriction provisions in the NER would not remove the ability of jurisdictions to impose mandatory restrictions under state legislation in the event of exceptional circumstances – it would just remove the requirement in the NER for this to be managed in NEMDE via a complex process of generator contracting and pricing this capacity at the MPC
- developments in the NER in relation to demand response and the enhanced RERT have reduced the likelihood of jurisdictions needing to call for mandatory restrictions
- the ongoing allocation of resources to maintain mandatory restriction pricing in the NER is not justified.

RECOMMENDATION 10: MANDATORY RESTRICTIONS

The Commission recommends that AEMO submit a rule change request to remove the mandatory restrictions framework from the NER.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered price cap
Commission	See AEMC
CPT	Cumulative price threshold
FCAS	Frequency control ancillary services
IPWG	Intervention pricing working group
LOR	Lack of reserve
NEM	National electricity market
NEMDE	National electricity market dispatch engine
MCE	Ministerial Council on Energy
MPC	Market price cap
MSPS	Market suspension pricing schedule
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
RERT	Reliability and emergency reserve trader
RRN	Regional reference node
SRMC	Short run marginal cost
TNSP	Transmission Network Service Provider
VCR	Value of customer reliability