Australian Energy Market Commission

RULE CHANGE

CONSULTATION PAPER

National Electricity Amendment (Participant compensation following market suspension) Rule 2018

Rule Proponent

Australian Energy Market Operator

17 May 2018

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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.

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1 Introduction

On 25 July 2017, the Australian Energy Market Operator (AEMO) submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission) that seeks to introduce participant compensation arrangements for electricity market suspension events based on the compensation arrangements for administered price periods.

AEMO considers that the proposed rule change will remove the incentive for market participants to minimise financial loss and await direction rather than voluntarily supporting the restoration and/or maintenance of electricity supply during a market suspension. In turn this will reduce the need for and cost of operational intervention to keep the power system reliable and secure during a market suspension.[1]

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

This paper:

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

Submissions on this consultation paper are due by no later than Thursday, **14 June 2018**. Details on how to lodge a submission are contained in Chapter 6 of this consultation paper. A template is available to help stakeholders provide their views on the issues raised in this paper.[2]

1 Australian Energy Market Operator (AEMO), *Rule change proposal: Market suspension rule changes - participant compensation*, p. 2 and p. 11.

2 Available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

2 Background

This chapter provides background to the rule change request. It also explains:

- the market suspension framework set out in the National Electricity Rules (NER)
- how prices are set when the market is suspended
- the NER compensation frameworks for directions and administered price periods (APP)

2.1 Background to the rule change request

2.1.1 Black System event

On 23 March 2017, AEMO published its final incident report into the South Australian (SA) state-wide power outage (referred to as the 'Black System event') that occurred on Wednesday 28 September 2016.[3]

As part of its investigations into the Black System event and subsequent period of market suspension, AEMO identified a number of issues with the framework for market suspension set out in the NER. The final incident report included a number of recommendations in relation to this framework, including that AEMO review market processes and systems, in collaboration with registered participants, to identify improvements and any associated NER or procedure changes necessary to implement those improvements.[4]

AEMO subsequently established a Market Suspension Technical Working Group (MSTWG) to discuss and develop proposed changes to the market suspension framework, including rule change proposals where appropriate.[5] This process identified the need for two rule changes – one relating to pricing during market suspension and the other relating to participant compensation following market suspension.

2.1.2 Pricing during market suspension

On 25 July 2017, AEMO submitted a rule change request to the AEMC relating to pricing during market suspension. This rule change request was considered urgent and was progressed using expedited processes so that changes could be in place before the summer of 2017/18.

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3 AEMO, *Black System South Australia 28 September 2016*, March 2017 is available at www.aemo.com.au.

4 See recommendation 17 of AEMO's final incident report. Two other recommendations in relation to market suspension were also made. These recommendations (15 and 16) are also described in AEMO's final incident report. See www.aemo.com.au.

5 The MSTWG comprised representatives from industry and the market bodies and met on four occasions between April and June 2017. Minutes of the MSTWG meetings were provided with the rule change request and are available at https://www.aemc.gov.au/sites/default/files/content/f687e061-3761-413f-bd1d-9d3f031bd999/Supplementary-information.pdf

On 10 October 2017, the AEMC made a final rule that simplified the process for setting prices if the spot market is suspended. Under the amended rules, AEMO can set prices as normal using the National Electricity Market Dispatch Engine (NEMDE) where practicable[6] or, if this is not possible, set prices in accordance with the market suspension pricing schedule (MSPS - a schedule based on average prices over the preceding four weeks).

This means that, if the market is suspended in future, the period of time in which the MSPS applies may be shorter than the 13 day period during which the South Australian market was suspended in late 2016. (While the MSPS applied throughout the 13 day market suspension, NEMDE was used to set dispatch targets, though not prices, for the last six days of the market suspension period.)[7]

Further information on the *Pricing during Market Suspension* rule change can be found on the AEMC website.[8]

2.1.3 Participant compensation following market suspension

At the same time as submitting the *Pricing during Market Suspension* rule change request, AEMO submitted a rule change request relating to participant compensation following market suspension. It is this rule change request that is the focus of this consultation paper.

AEMO proposes that a framework (based on that applicable to administered price periods) be introduced to compensate participants whose costs are not recouped via prices set out in the MSPS. This is designed to remove the incentive for market participants to minimise financial loss and await direction rather than voluntarily supporting the restoration and/or maintenance of electricity supply during a market suspension.

While market suspension events are rare, the market suspension in South Australia in late September/early October 2016 demonstrated that participants' financial losses can be significant where they voluntarily (without being directed by AEMO) contribute to power system restoration, reliability and security and their short run marginal costs are not covered by prices in the MSPS. For example, AGL has stated that it incurred substantial losses as a result of assisting in the power system restoration after the September 2016 Black System event (BSE).[9]

Currently there is no provision in the NER to compensate market participants for net losses when the MSPS applies.[10] However, market participants may be entitled to

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6 And, if the market has been suspended due to a jurisdictional direction to AEMO following the declaration of a state of emergency, the directing jurisdiction agrees that normal pricing can resume: clause 3.14.5(d)(3).

7 AEMO, *Black System South Australia 28 September 2016*, March 2017, p. 84.

8 See www.aemc.gov.au/Rule-Changes/Pricing-during-market-suspension

9 AGL, Submission to Inquiry into State-wide blackout of Wednesday 28 September 2016, 14 February 2017, pp18, 21 and 22.

10 Historically, the NER provided limited provision for market participants to claim compensation in relation to market suspension events but only where an administered price period coincided with a market suspension: see clause 3.14.6(a) and (a2) as they stood in NER Version 58, current as at

compensation if directed by AEMO to provide services during a market suspension event. At present, direction compensation is the only avenue for participant compensation in respect of market suspension pricing.[11]

AEMO regards the use of directions as a last resort which should not be incentivised by the Rules.[12] This is because administering directions is complex and resource intensive, particularly when the need for directions arises at a time of control room stress - such as during a market suspension. The process involves implementing counteractions (to minimise the number of affected participants, cost of compensation and impact on interconnector flows resulting from the direction), and running 'what if' scenarios to establish the price that would have applied but for the direction.

In addition, 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.[13] Accordingly, AEMO proposes that the current arrangements for compensating participants during an administered price period should be extended so that they also encompass periods when the MSPS applies ('MSPS periods').

As noted above, prices are set in accordance with the MSPS if, during a market suspension, it is not possible to set prices using the normal central dispatch and pricing process. The proposed compensation framework is not intended to operate throughout an entire future market suspension: it would only operate during periods when prices are determined by the MSPS.[14] Accordingly, the proposed framework is described in this paper as the 'MSPS compensation framework'.

2.2 Market suspension framework in the National Electricity Rules

The framework for market suspension is set out under rule 3.14 of the NER, specifically:

- clause 3.14.3 - Conditions for suspension of the spot market
- clause 3.14.4 - Declaration of market suspension
- clause 3.14.5 - Pricing during market suspension.

October 2013 when the COAG Energy Council lodged a rule change request seeking to change these provisions. In 2016, references to market suspension were removed from the provisions relating to APP compensation. The 2017 rule change regarding *Pricing during Market Suspension* clarified that market suspension pricing is subject to the administered price cap and administered floor price (or resultant price scaling) in the event that the cumulative price threshold is triggered during a market suspension. This could occur in the event that prices in the MSPS are very high (reflecting high prices in the preceding four weeks) or if an APP occurs in a neighbouring region and prices in the suspended region are scaled as a result. Thus, if an APP were to coincide with a market suspension event, participants who make a net loss during the APP could lodge a claim for compensation under the APP compensation framework.

11 Subject to the qualification that, if an APP coincides with a market suspension event, a participant may be able to claim compensation under the APP compensation framework – see footnote 10.

12 AEMO, *Rule change proposal: Market suspension rule changes – participant compensation*, p. 6.

13 NER, clause 3.1.4(a)(1)

14 AEMO, *Rule change proposal: Market suspension rule changes – participant compensation*, p. 11.

AEMO manages periods of market suspension in accordance with these provisions and having regard to its supporting operational procedures.[15] The market suspension framework incorporates a number of key components, as illustrated in Figure 2.1 and discussed in more detail in sections 2.2.1 to 2.2.5.

Figure 2.1 National Electricity Rules - Market suspension framework

Market Suspension	Suspension pricing	Inter-regional price scaling	Dispatch mechanism	Participant compensation
AEMO may suspend the market if at least one of three criteria applies: a. a black system event has occurred b. it is directed to do so by a jurisdiction under a state of emergency c. it assesses that the market is inoperable (e.g. due to IT failures or following a power system emergency) AEMO must publish a declaration to suspend the market and must inform participants prior to resuming the market.	AEMO has two options: a. normal dispatch pricing b. market suspension pricing schedule AEMO can apply dispatch pricing at any time during a market suspension if • in its reasonable opinion, it is practicable to resume central dispatch and the determination of dispatch prices and ancillary service prices, and • the market was suspended other than in response to a jurisdictional direction.	Price scaling occurs when a regional price is overridden, e.g. when the price is capped, floored or suspended. AEMO must revise (i.e. scale down) dispatch prices in adjacent regions if there is a "net energy flow" via one or more regulated interconnectors towards the suspended region. Dispatch prices for any flow from an adjacent region cannot be more than prices in the suspended region divided by the average loss factor.	If normal dispatch cannot occur and the pre-dispatch schedule is not current, AEMO will issue dispatch instructions to participants. There are no detailed procedures on how to operate the power system under extended periods of market suspension. AEMO developed an operational strategy for generator dispatch during the BSE in SA and has since published a high level procedure for future market suspensions.	**There is no provision in the rules to compensate market participants for net losses as a result of the application of the market suspension price schedule.** **However, market participants may be entitled to compensation if** • **directed by AEMO to provide services, or** • **an administered price period occurs during a MSPS period (in which case the participant may be entitled to lodge a claim for compensation under the APP framework).**

Source: AEMC.

2.2.1 Conditions for suspension of the electricity spot market

Under clause 3.14.3 of the NER, AEMO may suspend the spot market in a region for one of three reasons:

- the power system has collapsed to a black system
- a participating jurisdiction has declared a state of emergency under its emergency services or equivalent legislation and has subsequently directed AEMO to suspend the market
- AEMO has determined that it is impossible to operate the spot market in accordance with the NER, for example due to an IT failure or a power system emergency.

Market suspension in the National Electricity Market (NEM) is rare, having occurred only twice since commencement of the NEM in 1998.

1. The first market suspension was declared on 8 April 2001 following an IT system failure. All regions of the NEM were suspended for a two hour period commencing at 23:30.

15 AEMO, *Failure of market or market systems*, System Operating Procedure, SO_OP3706.

2. The second market suspension was declared on 28 September 2016 following a black system event in South Australia and subsequent ministerial direction. The South Australian region was suspended for nearly two weeks from 16:30 on 28 September to 22:30 on 11 October 2016.

2.2.2 Declaration of market suspension and recommencement

The declaration of market suspension under NER clause 3.14.4:

- allows AEMO to suspend central dispatch if necessary, and to determine prices in accordance with the MSPS while the underlying problem is being resolved (as detailed in section 2.2.3, AEMO can revert to dispatch pricing during a market suspension period in certain circumstances)
- informs market participants that a significant issue is occurring in the market.

Clause 3.14.4(d) provides the mechanism for concluding a market suspension event. For this to occur, AEMO must inform all registered participants that the spot market is to resume and the time that this will occur.

2.2.3 Market suspension pricing

This section describes how electricity and ancillary service prices are set during a market suspension. It reflects amendments to the NER made in late 2017 and thus differs from the rules that governed the market suspension in South Australia in late 2016.

Following the 2017 rule change, there are two options for setting prices during a market suspension:

1. **Normal dispatch pricing**: If the cause of a market suspension is not affecting AEMO's ability to run central dispatch and determine dispatch prices, spot prices and ancillary service prices in accordance with National Electricity Rules 3.8 and 3.9, this process should continue to be used. It allows for orderly bidding and dispatch, supporting efficient market outcomes.[16]
2. **Market suspension pricing schedule**: If in AEMO's reasonable opinion, it is not practicable to operate central dispatch and to determine dispatch prices and ancillary service prices then AEMO must set prices in accordance with the MSPS. This schedule is published weekly. AEMO calculates a rolling average of half-hourly prices for weekdays and weekends, using spot prices over the previous four weeks.[17]

AEMO can apply normal dispatch pricing at any time during a market suspension if, in its reasonable opinion, it is practicable to continue or resume central dispatch and the determination of dispatch prices and ancillary service prices.[18] The exception is where

16 NER, clauses 3.14.5(a)

17 NER, clauses 3.14.5(b) and 3.14.5(e). The current MSPS along with a guide to the MSPS are available on AEMO's website at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data/Market-Management-System-MMS/Market-Suspension-Pricing-Schedule .

18 NER, clause 3.14.5(a)

the market was suspended in response to a jurisdictional direction. In this case the relevant jurisdiction must agree to a return to dispatch pricing before AEMO can apply this pricing regime.[19]

2.2.4 Inter-regional price scaling

The NER[20] require prices in a neighbouring region or regions to be scaled when:

- the MSPS is being used to set prices in the suspended region, and
- there is a net energy flow on one or more regulated interconnectors from the neighbouring region/s toward the suspended region.

Prices in neighbouring region/s must not exceed the MSPS price, scaled by the average loss factor applicable to the energy flow from the neighbouring region to the suspended region. The purpose of price scaling is to prevent, or manage, the accumulation of negative inter-regional settlement residues.[21] During the South Australian market suspension, prices were scaled in Victoria, NSW and Queensland as a result of the application of the MSPS in South Australia. Further detail on the extent of the price scaling is available in section 6.3.2. of the AEMO report on the Black System event.[22]

2.2.5 Dispatch during market suspension

If a market suspension is in effect, AEMO is required to follow normal dispatch procedures where possible,[23] however the NER are not prescriptive about dispatch procedures where AEMO cannot use normal central dispatch processes.

AEMO has developed a tiered approach to bidding and dispatch during market suspension, depending on the circumstances of the market suspension:

- Bidding and dispatch will continue normally where AEMO considers it is practical and reasonably possible to do so. Where possible, dispatch instructions will be issued electronically via the automatic generation control system. Otherwise, AEMO may issue dispatch instructions in any other form that is practical in the circumstances.
- If, in AEMO's reasonable opinion, it is not possible to continue bidding and dispatch normally, then AEMO may use the most recently published valid pre-dispatch schedule if it is still current.
- If necessary, AEMO will issue directions to registered participants in accordance with the National Electricity Law (NEL) and the NER.[24]

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19 NER, clause 3.14.5(d)(3)

20 NER, clause 3.14.5(f)

21 NER, clause 3.14.5(f)

22 AEMO, *Black System South Australia 28 September 2016*, March 2017, p. 85.

23 NER, clause 3.14.5(a)

24 AEMO, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management/Guide-to-Market-Suspension-in-the-NEM, viewed 16 March 2018

AEMO's final incident report for the black system event in South Australia provides further detailed information on the framework for market suspension. Chapter 6 provides a summary of the NER provisions related to market suspension and the sequence of events from the system shutdown to the lifting of market suspension over the period 28 September to 11 October 2016.[25] It includes a section on directions and compensation related to the Black System event.[26]

2.3 Compensation frameworks

This section describes the existing compensation provisions in the NER.

AEMO's rule change request relates specifically to the arrangements for participant compensation in periods when the MSPS applies. Currently, the NER only provide for participant compensation in respect of directions issued by AEMO[27] and administered price periods.[28] The NER do not contain provisions for participant compensation in relation to MSPS periods. Through this rule change request, AEMO seeks to introduce participant compensation arrangements for MSPS periods based on the compensation arrangements for administered price periods.

2.3.1 Process for issuing and determining compensation due to directions

The NER detail the process for issuing directions and determining compensation. In summary the NER require AEMO to:

1. minimise the likely cost of, and compensation flowing from a direction, as well as the number of affected participants and effects on interconnector flows[29]
2. apply the regional reference node test: intervention pricing is invoked if a direction to a generator affects a whole region[30]
3. if appropriate, apply a "what-if" scenario (ie. what would have happened if the direction had not been issued?) to determine the dispatch price for the dispatch interval in which the direction occurs[31]
4. publish the "intervention settlement timetable" setting out the process and timeframes for determining compensation payable to directed participants and participants affected by the direction[32]

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25 AEMO, *Black System South Australia 28 September 2016*, March 2017, Chapter 6, pp. 82-88

26 Ibid, Section 6.4, pp. 85-86

27 NER, clauses 3.15.7, 3.15.7A and 3.15.7B

28 NER, clause 3.14.6

29 NER, clauses 3.8.1(b)(11) and 4.8.9(b)(1)

30 Intervention pricing is also known as "what-if" pricing – ie. what would the price have been if the direction had not been issued? "What-if" pricing is not triggered if a direction to a generator affects a confined part of the network that does not include the regional reference node: clause 3.9.3(d)

31 NER, clause 3.9.3(b)

32 NER, clause 3.12.1

5. automatically compensate directed participants for energy and ancillary services provided under direction at the 90th percentile of spot prices or ancillary service prices in the previous 12 months[33]
6. compensate directed participants for services other than energy and ancillary services based on a fair payment price to be determined by an independent expert[34]
7. allow a directed participant to claim additional compensation that covers loss of revenue and net direct costs that have not otherwise been compensated (referred to an independent expert if claim exceeds certain thresholds)[35]
8. adjust payments to or from affected participants so as to put them in the position that they would have been in but for the direction (if a participant disagrees with AEMO's adjustment, it may make a claim for additional costs - see further detail in Appendix A)[36]
9. recover any net compensation amounts from market customers in the region(s) for whose benefit the direction was issued.[37]

AEMO has issued an increasing number of directions in recent years (and particularly in recent months) and the number of compensation payments has risen accordingly.[38]

In most cases, directions have been issued in order to boost system security - for example, ensuring compliance with system strength requirements in South Australia. Directions have generally been issued in periods when low spot prices have prevented higher cost generators from recouping their short run marginal costs. Few directions have been issued in order to ensure system reliability - reflecting that, when the supply demand balance is tight, spot prices rise and enable most generators to recover their costs meaning no direction is required.[39]

In around 85% of cases, compensation recipients have been compensated based on the 90th percentile price and have not claimed additional compensation.

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33 NER, clause 3.15.7(c)

34 NER, clause 3.15.7A

35 NER, clause 3.15.7B

36 NER clauses 3.12.2 and 3.12.3

37 NER, clause 3.15.8

38 Directions were issued on one occasion in each of 2013 and 2014, none in 2015, four in 2016, and 12 in 2017. During 2018, directions have been issued on around 30 occasions (as at 3 May 2018). All but one were issued in South Australia. (The exception was a direction issued in NSW.) Note that several of these occasions involved directions being issued to multiple generators: see further at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Market-event-reports

39 Since 2010, only two directions have been issued to ensure system reliability – on 9 February and 1 March 2017. Further analysis is in SW Advisory & Endgame Economics, *Review of Intervention Pricing, Final Report prepared for AEMO*, 4 October 2017. This is available at the following link as part of the meeting pack for the first meeting in November 2017 (third item): https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

2.3.2 Process for determining compensation due to the application of an administered price

Administered price periods (APP) occur following a prolonged period of high prices. They are designed to limit market participants' exposure to financial stress which could ultimately impact market stability and integrity.[40] When the cumulative sum of spot prices in a region across a rolling seven day period exceeds the "cumulative price threshold" (CPT - currently set at $212,800), an administered price cap of $300/MWh is imposed, together with an administered floor price of -$300/MWh.[41] This administered price period continues until the rolling seven day cumulative price drops back below the level of the CPT. The APP ceases at the end of the trading day in which the cumulative sum of spot prices drops below the CPT.[42]

The potential for generators with high costs to incur a loss during such periods may create a disincentive for them to supply energy and ancillary services. This could in turn negatively impact the reliability and security of the electricity system. To minimise these disincentives, the NER allow participants to claim compensation where they incur a loss during an APP.[43]

Clause 3.14.6 of the NER details the process participants and the AEMC follow in determining compensation payable due to the application of an administered price cap (APC) or administered floor price (AFP). Note that the AEMC processes compensation claims relating to administered price periods,[44] while AEMO deals with directions-related compensation applications.[45] In both cases, AEMO is responsible for arranging the actual payment of compensation and the recovery of costs from market customers.[46]

The objective of this framework is to maintain the incentive for generators and network service providers to supply energy, ancillary service providers to supply ancillary services and market participants with scheduled load to consume energy during an APP.[47] By providing a compensation framework, the NER reduce the probability that market participants with high marginal costs will await a direction from AEMO rather than dispatch voluntarily during such periods.

In summary this compensation framework:

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40 Australian Energy Market Commission (AEMC) Reliability Panel, *Reliability standard and settings review 2018*, Draft Report, p. 7.

41 NER, clauses 3.14.1 and 3.14.2. The floor price is triggered pursuant to clause 3.14.2(d1)(2).

42 AEMC, *Final Rule Determination, National Electricity Amendment (Compensation arrangements following application of an administered price cap and administered floor price) Rule 2016, 4 February 2016*, p. 2.

43 AEMC, ibid, p. i.

44 NER, clause 3.14.6(j)

45 NER, clauses 3.15.7, 3.15.7A and 3.15.7B

46 NER, clause 3.15.10 in relation to APP and clause 3.15.8 in relation to directions

47 NER, clause 3.14.6(c)

- allows market participants to claim compensation if a net loss is incurred over an eligibility period;[48] this is based on whether total costs (direct and opportunity) exceed total revenue from the spot market during the eligibility period[49]
  - **scheduled or non-scheduled generators** can claim compensation if they are supplying in a region that is subject to an APC, or in a neighbouring region that is subject to price scaling, and incur loss
  - **market participants** can claim compensation in respect of a scheduled load dispatched in a region that is subject to an AFP, or in a neighbouring region that is subject to price scaling, and incur loss
  - **scheduled network service providers** can claim compensation if they are transferring power via a regulated interconnector into a region that is subject to an APC and incur loss
  - **ancillary service providers** can claim compensation for loss due to the application of an APC (does not apply to ancillary service providers in neighbouring regions)
- recovers compensation amounts from Market Customers in the cost recovery region (being the region subject to the APC)[50]
- references the AEMC's compensation guidelines which are used to inform participants of the process and assessment criteria for compensation[51]

Administered price periods are rare, having occurred only five times in the energy market since the inception of the NEM.[52] This reflects that spot prices in the NEM rarely exceed $300/MWh. In the last ten years (2008-2018), electricity spot prices exceeded $300/MWh for only 0.3% of the time.[53] When an APP is triggered in the energy market, the upper and lower bound (APC and AFP) apply in both the energy market and all eight ancillary service markets.[54] By contrast, when an APP is triggered in an ancillary service market, prices are capped only in that ancillary service market (not all eight markets) and are not also capped in the energy market.[55]

The first ever APP triggered in an ancillary services market occurred in October 2015. Over October and November 2015, several APPs occurred in South Australia and

48 'Eligibility period' is defined in NER clause 3.14.6 to mean 'the period starting at the beginning of the first trading interval in which the price limit event occurs in a trading day and ending at the end of the final dispatch interval of the last trading interval of that trading day'. There may be several eligibility periods within a single APP, or the APP may comprise only a single eligibility period.

49 NER, clause 3.14.6(b)

50 NER, clause 3.15.10(a1)

51 See: AEMC, *Final compensation guidelines under clause 3.14.6 of the National Electricity Rules*, 8 September 2016.

52 AEMC Reliability Panel, *Reliability standard and settings review 2018*, Draft Report, 21 November 2017, page 102.

53 AEMC analysis of NEM data as at April 2018

54 NER, clause 3.14.2(d1)

55 NER, clause 3.14.2(d2)

applied only in ancillary service markets.[56] These took place when planned outages of the Heywood interconnector meant that ancillary services had to be provided locally to ensure the system would remain secure in the event SA became separated from the rest of the NEM. The limited number of facilities that could provide ancillary services in SA resulted in high prices.[57]

Further APPs occurred in the SA ancillary services markets during 2016 and early 2017. Since the ancillary service market has diversified in South Australia, FCAS prices have fallen and no APPs have occurred since April 2017.[58] Despite the number of APPs in ancillary service markets, there have been no claims for compensation in relation to ancillary services provided during APPs.

There has only been one claim for compensation arising from an APP in the history of the NEM. This was the claim by Synergen that followed an APP in the South Australian energy market between 29 January and 7 February 2009. Synergen claimed compensation on the basis that the APC prevented it from recouping the costs of its Port Lincoln gas turbine and Snuggery power station. The AEMC determined that Synergen met the criteria for compensation, and that AEMO should pay it compensation of around $130,500. The process to determine this compensation claim, being the first of its kind, was complex and lengthy.[59]

The fact that there has only been one claim for compensation under the APP framework may reflect the fact that most generators are able to recoup their short run marginal costs when prices are able to rise as high as $300/MWh. Recent analysis for the AEMC Reliability Panel indicates that, at present, all generators - even the highest cost open cycle gas turbine power stations - have short run marginal costs of less than $300/MWh.[60]

It may also be that some features of the APP compensation framework do not create an environment that encourages potential claimants. For example, there is no automation of the compensation process. This is in contrast to the directions compensation framework, where eligible parties automatically receive payment at the 90th percentile price or fair payment price, where applicable, for services provided pursuant to a direction.

Further, while AEMO does not impose a charge for lodging a claim for additional directions-related compensation costs, the AEMC has discretion to recover its costs

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56 AEMC, *Final Rule Determination, National Electricity Amendment (Compensation arrangements following application of an administered price cap and administered floor price) Rule 2016*, 4 February 2016, p. i

57 AEMO, *NEM – Market Event Report – High FCAS prices in South Australia, October and November 2015*, December 2015, p. 11

58 Prices in the SA FCAS markets last exceeded $300/MWh in October 2017. The Hornsdale Power Reserve (the world's largest lithium-ion battery) in south-east SA commenced providing energy and ancillary services in December 2017.

59 See for example the chronology of the compensation assessment process set out in AEMC, *Final Decision, Compensation Claim from Synergen Power Pty Ltd*, 8 September 2010, Appendix A.

60 AEMC Reliability Panel, op cit, p. 101, referring to analysis undertaken by EY

from claimants when determining a claim for compensation under the APP framework.[61]

While the AEMC did not seek to recover its administrative costs from Synergen, it did set out the principles it would apply in exercising its discretion to recover future processing and administrative costs. The Commission stated that, for future compensation claims, the recovery of costs will be assessed on a case-by-case basis, having regard to the following principle: 'where the Commission considers that a compensation claim is not well-founded or where the conduct of the claimant has not supported an efficient process for resolving the claim, the external costs of processing the claim for compensation, namely the Panel's costs, will be shared equally with the claimant'.[62]

Since that decision, the NER provisions relating to the APP compensation framework and the related AEMC Compensation Guidelines (developed under clause 3.14.6) have been amended. Among other changes, the requirement to establish an expert panel has been removed. Instead, the Commission can call on external expertise if required. The revised Guidelines include a statement that "the Commission will exercise its discretion in deciding whether to recover processing and administrative costs from a claimant and will assess any costs to be recovered from a claimant on a case-by-case basis."[63]

This introduces an element of uncertainty about the cost of seeking compensation, which compounds the inherent uncertainty as to the amount of APP compensation that may be paid in response to a claim.

Another change to the framework is that the requirement for public consultation has been limited to claims involving opportunity costs, thus speeding up the process for direct cost only claims. Thus, if the Synergen claim were to be lodged today, the process would be less costly and time consuming as there would be no requirement for a three person panel and no requirement for public consultation given that the claim did not include opportunity costs.

Further changes were also made – for example calculating compensation based on an eligibility period rather than on a trading interval basis, and calculating net losses as the difference between total costs (direct and opportunity) and total spot market revenues earned over the eligibility period. Further information is available on the AEMC website.[64]

A more detailed comparison of the directions compensation framework and APP compensation framework is included in Appendix A.

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61 NER, clause 3.14.6(v)

62 AEMC 2010, *Final Decision, Compensation Claim from Synergen Power Pty Ltd*, 8 September 2010, pp14-15.

63 AEMC, *Final Compensation Guidelines under clause 3.14.6 of the National Electricity Rules*, 8 September 2016, p. 8

64 AEMC, *Final Rule Determination, National Electricity Amendment (Compensation arrangements following application of an administered price cap and administered floor price) Rule 2016*, 4 February 2016 available at https://www.aemc.gov.au/sites/default/files/content/4be8af5a-72ad-47f3-b9b5-2ee6e7a368a9/Final-Determination.pdf

2.4 Interactions between NER compensation frameworks

It is possible that multiple compensation frameworks could be triggered at the same time. For example, clause 3.14.5(c)(1) of the NER makes clear that an administered price period can be triggered when the market is suspended and the MSPS applies. If a compensation framework is developed for MSPS periods, participants who incur loss during such periods will need to determine whether to make a compensation claim under the APP framework or the MSPS framework. It is also possible that a direction could be issued during an APP that coincides with a MSPS period. In such a scenario, a market participant would - in future - have three possible compensation frameworks to consider: APP, MSPS and directions.

The Rules appear to contemplate that claims could be made under more than one framework[65] but do not include a formal mechanism to coordinate multiple claims and manage the risk of 'forum shopping'. Rather, this risk is managed through liaison between the relevant market bodies.

For example, the AEMC Compensation Guidelines supporting APP compensation claims set out the information to be provided to the Commission by the claimant and by AEMO. Section 4.1.2(5) states that AEMO should inform the Commission of 'any directions given to the claimant during the time periods for which the claim for compensation relates, and any compensation paid, to be paid, or under consideration to be paid as part of the directions compensation process'.[66]

Section 5.2.2 of the Guidelines provides that, in determining the amount of compensation payable, 'the Commission may take into account the value of any other source of compensation paid, to be paid, or under consideration to be paid, to the claimant where that compensation arises out of the same events and covers the same costs and opportunities foregone, if applicable, that are the subject of this compensation claim.'[67]

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65 Clause 3.15.7B(a3) sets out the matters that can be taken into account in calculating additional net direct costs claimed by a directed participant (in addition to the 90th percentile price compensation). These matters include in sub paragraph (7) 'any compensation which the Directed Participant receives or could have obtained by taking reasonable steps in connection with the relevant generating unit or scheduled network service being available'.

66 AEMC, *Final Compensation Guidelines under clause 3.14.6 of the National Electricity Rules,* 8 September 2016, p. 10

67 Ibid, p. 13

3 Details of the rule change request

The Rule change request from AEMO proposes that a MSPS compensation framework be included in the NER.

3.1 Issues raised in the rule change request

In its rule change request, AEMO provides its rationale for the rule change.[68] A number of key points are summarised below.

- In the current NER market suspension framework, there is no provision to compensate those participants who operate at a loss when the market is suspended and the MSPS applies. Compensation is only contemplated in the NER in relation to administered price periods and directions.[69]
- As prices in the MSPS are known in advance, generators who are not willing to supply at those prices may elect to withdraw or reduce their availability for dispatch, allowing them to seek compensation if they are subsequently directed.
- The use of directions is a last resort for AEMO and should not be incentivised by the rules. The administration of directions is complex and resource intensive, and can also have undesirable market outcomes.

The points above were illustrated by the 2016 South Australian market suspension which lasted for nearly two weeks. AEMO notes that applying the (then current) market suspension framework created the following operational and financial risks:

- the absence of a market suspension compensation framework meant some participants were incentivised to minimise financial losses rather than support the secure operation of the power system during the market suspension
- to restore and maintain the power system, AEMO was therefore reliant on either:
  - participant goodwill to manage system restoration, security and operation during the market suspension, or
  - issuing directions so that participants who operated at a loss due to the application of the MSPS could recover net costs through the directions compensation process.[70]

AEMO notes that, in the Black System event, all participants worked with AEMO to bring the network to a stable operating condition as soon as was practicable and without the need for directions. While directions were not issued during the power system restoration phase of the market suspension, two directions were issued in the final three days of the market suspension to maintain power system security.[71] AEMO also notes that, during a market suspension, control room operators should be focussed

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68 AEMO, *Rule change proposal: Market suspension rule changes - participant compensation*, section 3.2, pp. 6-7

69 NER, clauses 3.14.6, 3.15.7, 3.15.7A and 3.15.7B

70 AEMO, *Rule change proposal: Market suspension rule changes - participant compensation*, p. 4

71 AEMO, *Black System South Australia 28 September 2016*, March 2017, sections 6.4 and 6.5.

on restoring the market to a safe and stable operating condition rather than considering whether to issue directions.[72]

3.2 Proposed rule

AEMO considers that there are parallels between the application of an administered price cap and the application of the MSPS. For this reason, it proposes that the same form of compensation would be appropriate for the same categories of participants. Compensation would ensure that participants are not disadvantaged by continuing to participate in the market during high stress periods.[73]

The rule change request includes a proposed rule, although some aspects of the proposed rule need to be updated to reflect the *Pricing during market suspension* rule change.[74] The proposed rule extends the APP compensation framework to periods when the MSPS applies by making changes to:

- clause 3.14.6 (dealing with compensation due to the application of an APC or AFP),
- clause 3.15.10 (which deals with recovering the cost of APP compensation payments from market customers), and
- clause 3.15.10A (which deals with GST in relation to APC compensation payments and other payments)

Copies of the rule change request may be found on the AEMC website, www.aemc.gov.au.

72 AEMO, *Rule change proposal: Market suspension rule changes - participant compensation*, p. 6.

73 ibid.

74 Specifically, references in the rule change request to various provisions within NER clause 3.14.5 are no longer accurate because this clause was re-written for the *Pricing during market suspension* rule change.

4 Assessment framework

The Commission's assessment of this Rule change request must consider whether the proposed Rule promotes the National Electricity Objective (NEO).

From 1 July 2016, the National Electricity Rules (NER), as amended from time to time, apply in the Northern Territory (NT), subject to derogations set out in Regulations made under the NT legislation adopting the NEL.[75] Under those Regulations, only certain parts of the NER have been adopted in the NT.[76] As the proposed rule relates to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the proposed rule against additional elements required by the Northern Territory legislation.[77]

4.1 Rule making test

4.1.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[78] This is the decision making framework that the Commission must apply.

The NEO is:[79]

> "To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

Based on a preliminary assessment, the most relevant aspects of the NEO for the purpose of this rule change request are the efficient operation and use of electricity services for the long term interests of consumers of electricity with respect to the price of electricity, and the reliability and security of the national electricity system.

4.1.2 Proposed assessment framework

To determine whether the proposed rule, if made, is likely to promote the NEO, the following principles may be considered as part of the AEMC's assessment of the rule change request:

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75 National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations

76 For the version of the NER that applies in the Northern Territory, refer to: http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/National-Electricity-Rules-(Northern-Territory)

77 National Electricity (Northern Territory) (National Uniform Legislation) Act 2015

78 Section 88 of the NEL

79 Section 7 of the NEL

- **Effect on incentives** – whether the proposed rule change will incentivise market participants to help restore and/or maintain a reliable and secure electricity supply during MSPS periods whilst not encouraging inefficient bidding and dispatch outcomes.
- **Transparency and predictability** – whether the proposed rule provides clear and predictable arrangements for compensation during MSPS periods, thereby facilitating efficient decisions by participants.
- **Risk management** – whether the proposed changes improve the ability of market participants and market bodies to manage risks during and after MSPS periods.
- **Regulatory and administrative burden** – whether the benefits of the proposed rule change are proportional to the regulatory and administrative burden on market bodies and participants, and costs passed onto consumers and tax payers.

4.1.3 Making a more preferable rule

Under s. 91A of the NEL, the Commission may make a rule that is different (including materially different) to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule will or is likely to better contribute to the achievement of the NEO.

Issue 1 Assessment framework

1. **Is the assessment framework appropriate for considering the proposed rule changes?**
2. **Are there other relevant considerations that should be included in assessing the proposed rule changes?**

5 Issues for consultation

Taking into consideration the assessment framework, a number of high level policy issues and detailed design considerations have been identified for initial consultation.

This section discusses what elements are appropriate to include in a MSPS compensation framework, if one is to be developed, and seeks stakeholder views. It also discusses whether existing compensation frameworks are suitable to apply to MSPS periods, or whether a new framework - potentially combining elements of other frameworks - should be considered.

Stakeholders are encouraged to comment on these issues as well as any other aspect of the rule change request or this paper, including the proposed assessment framework.

5.1 Is a compensation framework required?

A threshold issue that arises is whether a compensation framework is in fact required.

AEMO considers that the current market suspension framework created operational and financial risks during the SA market suspension and the MSPS compensation framework is proposed as the means to address these (see Section 3.1).[80]

A possible alternative to creating a new compensation framework could be to change the basis of the MSPS so as to better incentivise generators to participate voluntarily during MSPS periods, rather than await a direction. However, the circumstances that must exist in order to trigger a market suspension (black system, state of emergency, IT failure or similar) are highly unusual. This suggests that it would be difficult to establish in advance a price schedule that could efficiently incentivise generators, without imposing unwarranted costs on customers, in the wide range of circumstances that could arise following a market suspension.

Issue 2 Is a compensation framework required?

1. **Is a compensation framework for MSPS periods required?**
2. **If not, what other options (if any) should be considered?**

5.2 Effect on incentives

The relationship between any MSPS compensation framework (if one is developed) and the directions compensation framework is important when considering the incentives facing market participants during a MSPS period. For example, if market participants were to form a view that the MSPS compensation framework was less financially favourable, or was unduly complex to access, they may still await a direction from AEMO in order to have access to the compensation framework applicable to directions. This would undermine AEMO's objective in lodging the rule change request – namely,

80 AEMO, *Rule change proposal: Market suspension rule changes – participant compensation*, p. 4.

to remove the incentive for market participants to await a direction rather than working collaboratively with AEMO to assist with restoration or maintenance of a secure and reliable electricity supply during a market suspension.[81]

5.2.1 Bidding during MSPS periods

The nature of a compensation framework can have important impacts on bidding behaviour, much like the impact of prices where they are known in advance. When the MSPS applies, prices for each trading interval are known in advance meaning generators can decide whether it is economic to generate having regard for the revenue they can earn under the MSPS. Where prices are too low, generators may bid unavailable and await a direction from AEMO in order to ensure that their costs are covered. In future, if a MSPS compensation framework is developed, generators' decisions will likely have regard both for the schedule price and (if known or estimable) the extent of compensation they can recover where that price is insufficient to cover their costs.

During the South Australian market suspension, normal central dispatch processes resumed from 5 October and continued until the market suspension ended on 11 October.[82] However, due to the nature of the rules at that time (i.e. before changes were made to simplify the market suspension pricing framework), it was not possible for AEMO to resume central pricing processes. Instead, prices were set by the MSPS. This meant that:

> 'parties participating in the central dispatch process were responding to price signals provided by the market suspension pricing schedule... that were unrelated to market conditions at that time, rather than to price signals created by the normal central dispatch process. This had the following consequences:
>
> - a large proportion of generation was offered at negative prices resulting in negative dispatch prices which were then overridden by the market suspension pricing schedule
> - AEMO issued directions to secure the power system with plant that had been displaced by the plant offering low prices.'[83]

AEMO concludes that market suspension pricing may have led to market participants bidding at low prices to maintain dispatch volumes in the knowledge this had no price impact.[84] AEMO notes that, in South Australia (as elsewhere), wind farms commonly offer their entire capacity at the market floor price (MFP) of -$1,000/MWh, whereas thermal generators typically offer only their minimum safe operating level at the MFP.[85]

81 ibid

82 AEMO, *Black System South Australia 28 September 2016, March 2017*, pp. 84, 86

83 AEMC, *Rule Determination, National Electricity Amendment (Pricing during market suspension) Rule 2017*, 10 October 2017, p. 15

84 AEMO, *Market Suspension Change Proposals - Discussion Paper for distribution to NEM Market Suspension Technical Working Group*, April 2017, p. 5

85 AEMO, ibid, pp 5-6

During MSPS periods, no market signal exists to resolve an excess generation situation. Instead, when several generators have bid available at the same price (e.g. the MFP) and available capacity exceeds demand, clause 3.8.16 of the NER provides that AEMO is to dispatch each generator with an equal-priced offer in proportion to the volumes offered. This created problems in South Australia as the pro-rating process meant that some thermal generators were dispatched at levels below their minimum safe operating level.[86]

The South Australian example illustrates how, when prices are known in advance, bidding behaviour can be impacted such that low cost generators displace higher cost generators when the output of the latter may be needed for system security. Any MSPS compensation framework (if one is developed) must be designed so as not to create new incentives leading to similarly perverse outcomes, creating a new problem while seeking to solve another.

In particular, it is important to keep in mind that – while directions are issued to a select few participants – a new MSPS compensation framework would likely apply to all eligible parties who opt to provide services during a MSPS period and, in doing so, incur a loss. This is an important distinction. The ('ex post') directions compensation framework would be available only to those generators to whom AEMO has issued directions (after first taking action to limit the cost of compensation – eg. identifying which generators can supply the required services at least cost). By contrast, the proposed MSPS compensation framework would apply ('ex ante') to all eligible parties. As such, any inefficient incentives created by the compensation framework may be costly.

For example, if a compensation framework were developed that provided generators with a high degree of confidence that they would recoup their costs via compensation, they may bid all their capacity at the MFP in order to be dispatched and then recoup their costs via compensation. This could lead to uneconomic outcomes by displacing lower cost generators (via the pro-rating process) and resulting in higher costs for consumers (who ultimately bear the cost of compensation payments).

Thus the desirability of creating a compensation framework with some element of predictability (as in the case of the directions compensation framework, in which generators are automatically compensated at the 90th percentile price) needs to be weighed against the risk of creating perverse bidding incentives and outcomes that are inconsistent with the NEO.

One way to address this could be, for example, to develop a framework that compensates generators by reference to the short run marginal costs (SRMC) of different generator types, rather than based on the 90th percentile price (similar to a "cost plus" approach in building contracts). Another option could be to compensate generators based on a percentile price that is lower than the 90th percentile. This could help strike a balance between, on the one hand, incentivising generators to help maintain reliability and security and, on the other, avoiding inefficient dispatch outcomes and excessive compensation costs being recovered from consumers.

86 ibid.

5.2.2 Bidding during Administered Price Periods

The situation during MSPS periods, when prices are known in advance, differs from the situation that exists during an APP. During APPs, the price is set using the normal central dispatch and pricing process but it is subject to lower and upper bounds of ±$300/MWh. Unlike MSPS periods, the price that will apply in a given trading interval during an APP is not known in advance and generators will need to submit bids that reflect their willingness to be dispatched, informed by factors such as their SRMC and bidding strategies.

This means that, while prices are subject to a defined band, the bidding process in an APP is the same as that which applies normally.[87] Thus, the potential for the outcomes seen during the South Australian market suspension is not present during an APP because prices are set by a 'genuine' bidding process, not a pre-determined schedule.

If, during an APP, generators are unable to recover their costs, they may opt to apply for compensation (something which, as noted, has only occurred once - in 2009) or may bid unavailable and then await a direction from AEMO. This would then enliven the compensation framework applicable to directions (compensation at the 90th percentile price plus the ability to claim for additional costs). While the 90th percentile price will generally be lower than the APC of $300/MWh, it is noted that prices during an APP can fluctuate between the lower and upper bounds – meaning that the spot price during an APP may be well below the 90th percentile price.

Figure 5.1 overleaf shows the 90th percentile price for energy (calculated annually) over the last eight years. As can be seen, the 90th percentile price is a dynamic metric that is able to reflect changing market conditions. The highest 90th percentile prices are those seen in Tasmania in 2015-16 (due to the Basslink outage) but, even then, the highest 90th percentile price was $245/MWh and did not reach the administered price cap ($300/MWh). Similar analysis of the eight FCAS markets indicates that the 90th percentile price is generally low, with the 90th percentile price in the most costly ancillary service market only reaching levels of less than $50/MWh.

87 NER, clause 3.14.2(d)

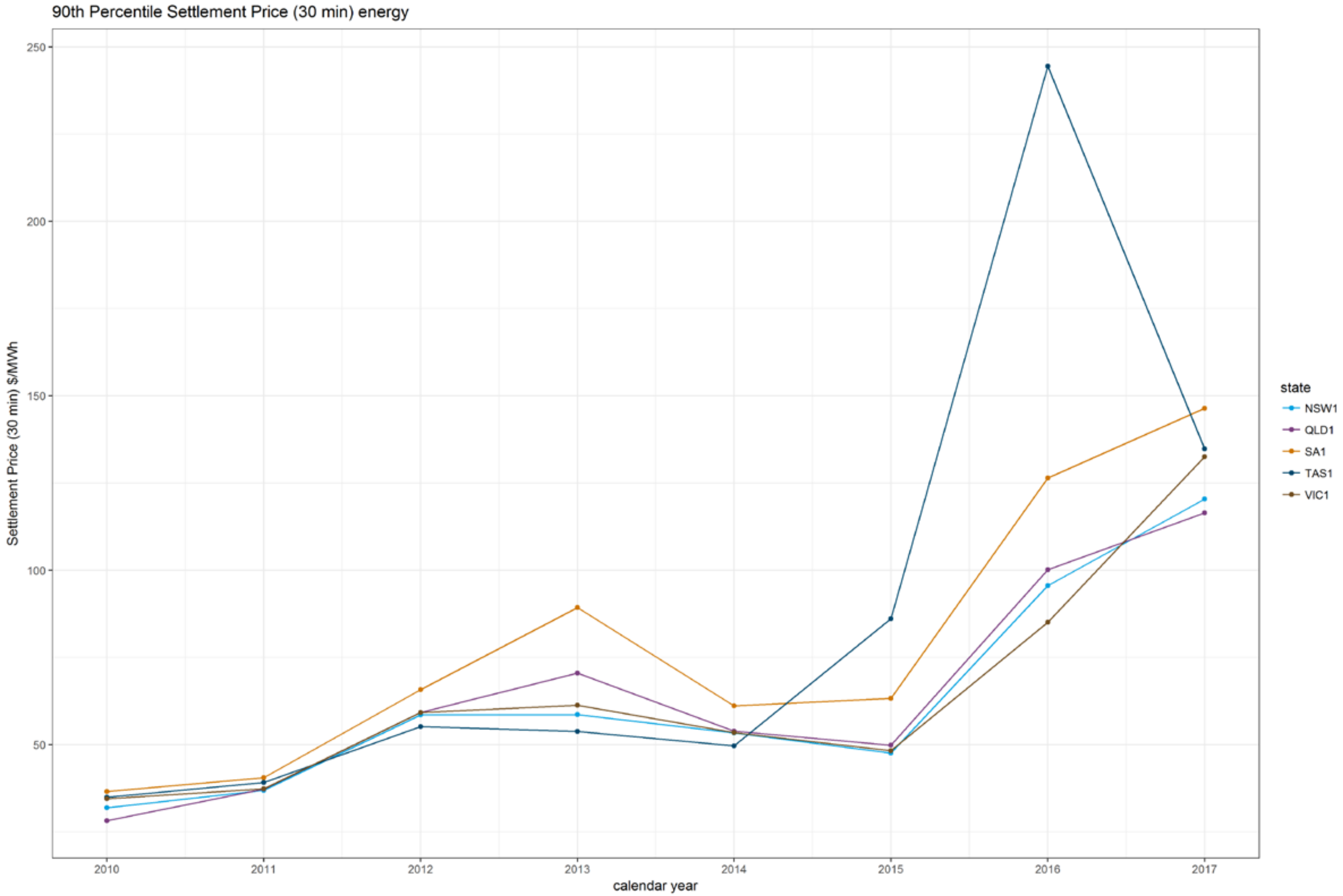

Figure 5.1: 90th percentile energy prices (calculated annually) since 2010. Source: AEMC

5.2.3 Objective of compensation

As noted in section 2.3.2, the objective of the APP compensation framework is to maintain the incentive for generators to supply energy, ancillary services providers to supply ancillary services and market participants with scheduled load to consume energy. While the directions compensation framework does not have a stated objective, the practical effect of the framework is to enable directed parties to recover their costs, and to put affected parties in the position that they would have been in but for the direction. One stakeholder has suggested that a clearer articulation of the purpose of the directions compensation framework would be beneficial.[88]

AEMO's proposed MSPS compensation framework aims to incentivise generators and ancillary service providers to participate in the suspended market voluntarily rather than withdraw capacity and await a direction. In this way, the objective is similar to that of the APP compensation framework.

A question arises as to whether the proposed MSPS compensation framework should also seek to incentivise market participants with scheduled loads to consume energy, consistent with the APP compensation framework objectives. (During an APP, market participants with scheduled loads may incur a loss if the administered floor price of -$300/MWh is higher than the spot price would otherwise have been – for example, -$1,000/MWh.) It may be that, during a market suspension, incentivising market participants with scheduled loads to consume energy is less important than providing incentives to generators and ancillary service providers.

Issue 3 Creating appropriate incentives

1. **What should be the objective of the proposed MSPS compensation framework?**
2. **How should a MSPS compensation framework effectively incentivise voluntary participation during MSPS periods without also incentivising inefficient bidding behaviour and dispatch outcomes?**

5.3 Transparency and predictability

The design of a compensation framework involves a trade-off between the accuracy of the compensation payment and the predictability of revenue outcomes for market participants.

Under the APP framework, there is little predictability about the outcome of the compensation claim process since it adopts a case by case approach, reviewing the list of costs submitted by each claimant. By contrast, under the directions compensation framework, market participants know in advance that they will at least receive the 90th

88 Synergies, *Final report on compensation related to directions that occurred on 1 December 2016: an independent expert report prepared for AEMO*, June 2017, p. 38.

percentile price (or fair payment price, if one has already been established, for services other than energy and ancillary services).

This will be an important consideration in determining whether to participate voluntarily, or bid unavailable and await a direction. As such, the predictability (or otherwise) of the compensation framework is an important factor when considering the incentives facing market participants.

The degree of accuracy under the APP framework is likely to be relatively high since the compensation payment is determined based on the itemised list of costs submitted by the claimant. By contrast, accuracy is lower under the automatic part of the directions compensation framework as the 90th percentile price payment is unlikely to accurately reflect the costs borne by a given participant.

The use of the percentile price approach may result in some parties being overcompensated relative to the costs they incurred. However, the impact on market customers of this over payment is mitigated by the lower administrative costs associated with this automated element of the framework. For those directed participants who are under-compensated by the 90th percentile price, the ability to claim additional costs means that directed participants can still seek compensation that more accurately reflects their actual costs.

5.3.1 How should compensation be calculated?

These considerations of incentives, transparency, predictability and accuracy are relevant in determining what features to include in the proposed MSPS compensation framework.

The AEMO proposal is to extend the APP compensation framework so that it also applies to MSPS periods. This approach has the benefits of greater accuracy and avoiding the potential for perverse bidding and dispatch outcomes (since participants will not know in advance how much compensation they can recover). On the other hand, this uncertainty may mean generators prefer to await a direction. Given this, there may be value in considering a hybrid approach that combines elements of both the APP and directions frameworks.

AEMO notes in its rule change request that much of the directions process is not applicable during a MSPS period. In particular, AEMO notes that "the directions process includes a what-if scenario run which identifies affected parties, both winners and losers, in one or more regions. This process is not applicable during the application of the market suspension price schedule and much of the directions compensation process therefore loses relevance during this time."[89]

Similarly, a recent review of Intervention Pricing notes that the purpose of "what-if" pricing is to preserve the price signal that would have been provided to the market if AEMO had not issued the direction. The intention is to avoid muting the scarcity signal

89 AEMO, Rule change proposal: Market suspension rule changes - participant compensation, p. 6.

that would (but for the direction) convey to investors that there is a need for additional capacity in the market.[90]

In its report on the directions issued to two generators in the final days of the South Australian market suspension, AEMO notes that intervention pricing was not implemented in connection with those directions as they were issued during a period of market suspension when the SA spot price was determined by the MSPS.[91] The Intervention Pricing Review also notes that, from an economic perspective, "what-if" pricing (or "but for" pricing) has no purpose in a suspended market. "The economic rationale for intervention pricing is to preserve the market price signal - once the market is suspended, there is no connection between price and scarcity. The payments during the market suspension are not intended to signal scarcity."[92]

While this analysis confirms that much of the directions compensation process is not applicable during a MSPS period, there may nonetheless be value in considering whether some key elements of the framework - for example, using a nominated percentile price to calculate the base compensation amount (rather than applying a case by case approach as under the APP framework) - have merit in designing a MSPS compensation framework. Such approaches could enhance predictability and thus have a greater impact on the incentives facing generators during a MSPS period.

Issue 4 Elements of proposed MSPS compensation framework

1. **How should compensation be calculated?**
    a. **Is the APP compensation model the appropriate approach?**
    b. **What are the advantages and disadvantages of alternative approaches to the APP compensation model – for example, a "cost plus" approach or the use of a pre-determined percentile price?**
    c. **Does a hybrid approach warrant consideration, for example combining elements of different frameworks?**
    d. **Should there be an element of automation in the calculation of compensation?**
    e. **What is an appropriate balance between predictability and accuracy of compensation?**

90 SW Advisory and Endgame Economics, *Review of Intervention Pricing, Final Report prepared for AEMO*, 4 October 2017, pp 1, 7.

91 AEMO, *NEM Event - Directions to thermal synchronous generators during South Australian Market Suspension - 9 October and 11 October 2016*, 26 April 2017, p. 9.

92 SW Advisory and Endgame Economics, op cit, p. 12.

5.3.2 Who should be eligible to claim compensation?

Given the objective of the rule change request, it seems reasonably clear that generators in the suspended region which incur a loss during a MSPS period should be entitled to, or eligible to claim, compensation. However, it is less clear as to what other parties should be entitled to or eligible to claim compensation. For example, should parties in neighbouring regions be eligible to claim compensation as a result of scaling?

Consideration could be given to a hybrid approach – for example, some parties could be entitled to receive compensation automatically (with the ability to make a further claim for additional costs), while others could be eligible to lodge a claim for compensation (rather than receive it automatically).

Under the APP framework, if prices in one region are set by the APC or AFP, prices in neighbouring regions are scaled to prevent negative inter-regional settlement residues.[93] Scaling is also undertaken during MSPS periods for the same reason.[94]

During an APP, market participants in neighbouring regions can claim compensation if they incur a loss due to the impact of scaling. (That is, if their total costs – direct and opportunity – during the eligibility period exceed the total revenue they earn from the spot market during that period.) Eligible participants include scheduled generators and non-scheduled generators, market participants in respect of scheduled loads, and scheduled network service providers. The only exception is ancillary service providers, who can only claim compensation in the event that they incur loss as a direct result of the application of an APC in the region in which they are supplying services (ie. they cannot claim for loss incurred due to scaling).[95]

As noted previously, there has only been one compensation claim in respect of an APP and this did not involve losses due to scaling.

While the directions framework does not provide for scaling, AEMO is responsible for ensuring that 'affected participants' are in the position that they would have been in had the direction not been issued.[96] AEMO also estimates the level of flow on all relevant interconnectors that would have occurred had the direction not been issued.[97]

The APP framework provides for eligible parties who suffer loss due to scaling to lodge a claim for compensation. By contrast, the directions framework provides that AEMO will - via the settlement process - automatically adjust (both positively and negatively) the position of affected participants, subject to a threshold of $5,000 per trading interval.[98]

A question arises as to whether any MSPS compensation framework should compensate parties in neighbouring regions who suffer loss and, if so, how that compensation should be calculated. Options include calculating compensation using a

93 NER, clause 3.14.2(e)

94 NER, clause 3.14.5(f)

95 NER, clause 3.14.6(a) – definition of price limit event, and clause 3.14.6(b)

96 NER, clause 3.12.2(a)(1)

97 NER, clause 3.12.2(c)(2)

98 NER, clause 3.12.2(b)

semi-automated process (as in the directions framework) or by allowing such parties to lodge a claim for compensation (as in the APP framework).

Similarly, should any MSPS compensation framework allow market participants to receive or claim compensation with respect to scheduled loads? As discussed in section 5.2.3, it remains to be determined whether the objectives of the proposed MSPS compensation framework should include incentivising market participants with scheduled loads to consume energy.

Market participants with scheduled loads are entitled to lodge a claim for compensation under the APP framework, both where losses are incurred directly due to the application of the AFP or as a result of scaling.[99] Under the directions framework, market participants with scheduled loads are automatically compensated via the settlements process (again subject to the $5,000 threshold noted above).[100]

A further question is the degree to which non-scheduled generators should be entitled to or eligible to claim compensation. They were included in the APP compensation framework when changes were made to that framework in 2016, meaning that they can lodge a claim for compensation in the event they incur a loss during an administered price period.

Non-scheduled generators do not participate in central dispatch and do not submit a dispatch offer but, where non-scheduled generators are classified as market generators[101], they are potentially subject to direction by AEMO under clause 4.8.9.[102] While such non-scheduled generators would be entitled to receive compensation paid at the 90th percentile price under clause 3.15.7, there is no provision in clause 3.15.7B for non-scheduled generators to seek compensation with respect to additional costs. Non-scheduled generators are also not subject to the provisions relating to affected participants.[103]

Issue 4 Elements of proposed MSPS compensation framework

2. Who should be entitled to or able to claim compensation?

a. Should parties in neighbouring regions be entitled to, or eligible to claim, compensation if they incur a loss due to scaling?

b. To what degree should non-scheduled generators be entitled to, or eligible to claim, compensation?

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99 NER, clause 3.14.6(a) – para (2) of definition of price limit event, and clause 3.14.6(b)(2)

100 NER, clause 3.12.2(a)(2)

101 NER, clause 4.8.9(a1)(1) refers to directions requiring action to be taken by "scheduled plant or a market generating unit". Generators are classified in accordance with chapter 2 of the NER – see clause 2.2.3 and 2.2.4. A guide to participant categories in the NEM is available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/Participant-Categories-in-the-NEM.pdf

102 AEMC, *Final Rule Determination, National Electricity Amendment (Compensation arrangements following application of an administered price cap and administered floor price) Rule 2016*, 4 February 2016, p. 25

103 The definition of "affected participant" in NER chapter 10 refers only to scheduled generators and scheduled network service providers.

> c. **Should market participants be entitled to, or eligible to claim, compensation with respect to scheduled loads?**

5.3.3 What costs should be claimable?

As part of any MSPS compensation framework, there needs to be clarity around the costs that are to be claimable or designed to be covered. The directions and APP frameworks provide some points of reference for consideration.

Under the directions framework, directed participants can claim additional compensation (in addition to the 90th percentile price compensation) to recover their net direct costs and loss of revenue. Matters that may be taken into account in calculating net direct costs are set out in clause 3.15.7B(a3). By contrast, no further detail is provided as to what should be considered in calculating 'loss of revenue'.

The APP framework enables claimants to seek compensation for their direct costs and opportunity costs. Guidance as to what costs can be claimed is set out in Compensation Guidelines, developed by the AEMC in accordance with clause 3.14.6(e) of the NER. In assessing APP compensation claims, the AEMC must apply these guidelines unless it is satisfied that there are compelling reasons not to do so.[104]

The types of direct costs specified in the APP Compensation Guidelines are similar to those that can be referenced in claims for additional directions related compensation: eg. fuel costs, incremental maintenance and staffing costs, and acceleration of maintenance work.

The NER defines opportunity costs as "the value of opportunities foregone by the claimant due to the price limit event as defined in the compensation guidelines".[105] The APP Compensation Guidelines define opportunity cost as follows:

> Opportunity cost is the value of the best alternative opportunity for eligible participants during the application of a price limit event or at a later point in time. The opportunity cost is the foreclosure of this alternative opportunity to use scarce capacity or resources more profitably at the same point in time or at a later point in time.[106]

For example, a generator may incur opportunity costs if it provides services in an ancillary services market at a time when prices in that market are subject to an APC, while prices in the energy market are uncapped (and high).[107] A generator could also incur opportunity costs if, for example, they were to use scarce resources (such as water in a storage reservoir) in order to provide energy during an APP rather than keep that water in storage for use at a later time when energy market prices are uncapped and higher than during an APP.[108]

104 NER, clause 3.14.6(s)(2)

105 NER, clause 3.14.6(a)

106 AEMC, *Final Compensation Guidelines under clause 3.14.6 of the National Electricity Rules*, 8 September 2016, p. 16

107 ibid, p. 18

108 ibid, p. 17

While the Guidelines refer to opportunity costs rather than expressly to 'loss of revenue' (as is the case in the directions compensation framework), the Guidelines make clear that matters such as 'price differences between markets' are relevant factors to be considered by the AEMC.[109] This suggests that there is some commonality between the APP and directions compensation frameworks with respect to revenue related losses.

However, AEMO has noted that claims relating to losses in the FCAS market during an energy direction have in the past been rejected due to clause 3.12.2(j)(3).[110] Clause 3.12.2(j) sets out the items that AEMO is to consider in determining the compensation to be paid to affected participants in order to put them in the position that they would have been in but for the direction. Subparagraph (3) within that clause requires AEMO to consider the regional reference price published pursuant to clause 3.13.4(m) – being the spot price for electricity (but not ancillary services) at the regional reference node. AEMO has queried whether this is appropriate.[111]

Issue 4 Elements of proposed MSPS compensation framework

3. **What costs should be claimable? Direct costs, loss of revenue, opportunity costs?**

5.3.4 Should any thresholds apply?

It will be necessary to determine whether any thresholds should apply in the context of a MSPS compensation framework.

In the directions compensation framework, AEMO applies a $5,000 threshold per trading interval below which it will not adjust settlements or allow claims for additional compensation.[112] This is currently set on a trading interval basis but recent discussions with stakeholders have explored whether this should instead apply "per intervention event" so that market participants are not adversely affected where an intervention event comprises a number of trading intervals.[113]

There is no such threshold in the APP compensation framework. In practice, however, it is unlikely that claimants would seek compensation for such small sums given the cost involved in making a claim.

109 ibid.

110 See for example Synergies, *Final report on compensation related to directions that occurred on 1 December 2016*, June 2017. This independent expert report prepared for AEMO concluded that compensation for FCAS losses was not payable due to the wording of this clause.

111 Discussed in AEMO slide pack presented to Intervention Pricing Working Group, Meeting 3, 15 February 2018, available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group

112 NER, clauses 3.12.2(b), 3.12.2(i) and 3.15.7B(a4)

113 Discussed in AEMO slide pack presented to Intervention Pricing Working Group, Meeting 3, 15 February 2018, op cit

Issue 4	Elements of proposed MSPS compensation framework

4. Should any minimum thresholds apply below which compensation is not payable?

5.3.5 How should compensation payment costs be recovered?

Another issue to be resolved is how costs should be recovered under any MSPS compensation framework. Should they only be paid by customers in the region in which the market suspension occurred? Alternatively, should customers in other regions contribute to compensation costs where they also receive a benefit?

Under the APP framework, compensation payments are funded by market customers in the region in which the administered price cap or administered floor price applied (the 'home region').[114] This is on the basis that such customers are the primary recipients of the enhanced reliability associated with generators continuing to operate during an APP.[115] The effect of this is that home region customers may pay compensation not only to generators in the home region, but also to generators and network service providers in regions affected due to price scaling.

A different approach is adopted in the directions compensation framework, under which compensation costs are to be recovered from market participants having regard to the relative benefit each region receives as a result of the direction.[116] This means that cost recovery is not limited to the region in which the direction was issued.

It is notable that, during the SA market suspension, prices were affected in regions as far away as Queensland.[117] This highlights the importance of considering how the costs of any future MSPS compensation payments should be recovered.

Issue 4	Elements of proposed MSPS compensation framework

5. How should compensation payment costs be recovered?

5.3.6 Claiming compensation under more than one framework

As discussed in section 2.4, up to three compensation frameworks could in future apply to a single trading interval – any MSPS framework, as well as the existing APP framework and directions framework. Given this, it may be appropriate to include a provision in any MSPS compensation framework to manage instances where claimants have the option to seek compensation with respect to a MSPS period under more than

114 NER, clause 3.15.10

115 AEMC, *Final Rule Determination, National Electricity Amendment (Compensation arrangements following application of an administered price cap and administered floor price) Rule 2016*, 4 February 2016, p. 43.

116 NER, clause 3.15.8

117 AEMO, *Black System South Australia 28 September 2016*, March 2017, p. 85.

one framework. For example, it may be appropriate to include a mandatory requirement on the relevant market body to take into account claims pending or paid under other compensation frameworks with respect to the same time period.[118] This would be consistent with the NEO, noting that consumers ultimately fund compensation payments.

Issue 4	Elements of proposed MSPS compensation framework
6.	**Should the framework include a provision to manage situations where compensation claims could be made under more than one framework with respect to the same event? If so, what approach should be adopted?**

5.4 Risk management

A compensation framework for MSPS periods should allocate risks to those parties best able to manage them. Relevant risks include:

- operational risks facing AEMO as it seeks to restore/maintain a reliable and secure electricity supply during a market suspension
- cost risks facing generators who need to earn sufficient revenue (through price and/or compensation) to cover their SRMC
- cost risks facing market customers (and ultimately consumers), who bear the cost of compensation payments
- cost risks facing the market bodies which administer compensation frameworks (the costs of which are passed on to consumers and taxpayers).

The rule change request reflects AEMO's desire to reduce operational complexity and risk during market suspensions by removing the incentive for generators to bid unavailable and await a direction. Effectively managing this risk requires that appropriate incentives are put in place such that, to an efficient degree, participants are incentivised to participate rather than await a direction. As discussed above, care is needed in developing the MSPS compensation framework to avoid creating a new risk - namely, the potential for perverse bidding behaviour and inefficient dispatch outcomes.

Risks to generators centre on their ability to recover their short run marginal costs if they decide voluntarily (without a direction) to participate in the restoration or maintenance of supply during a MSPS period. To the extent that the quantum of compensation available is unknown, generators still face a residual risk that they will not be able to recoup their costs. Thus, even with a new compensation framework in place, this residual risk will have a bearing on generators' decision making.

Similarly, the costs associated with making and substantiating a compensation claim are another factor that generators will need to manage as part of their decision making.

118 Such an approach would differ from the permissive discretion included in section 5.5.2 of the current APP Compensation Guidelines. See discussion in section 2.4 above.

The timelag between costs being incurred and compensation being recovered is also relevant.

The efficacy and efficiency of the compensation framework will in part be a function of the degree to which it reduces the above risks, in order to incentivise participants to support AEMO in restoring or maintaining a reliable and secure electricity supply during MSPS periods.

While consumers are the beneficiaries of compensation frameworks that incentivise participants to help maintain a secure and reliable electricity supply, they also face risks associated with the cost of compensation payments. NER clauses 3.15.8 and 3.15.10 provide for the recovery from market customers of directions compensation payments and APP compensation payments respectively. As Origin Energy noted in its July 2010 submission to the AEMC's consideration of the Synergen compensation claim, market customers cannot hedge this risk since the timing and quantum of APP compensation payments (as with directions compensation payments) are not knowable in advance.[119]

Issue 5 Risk management

1. **What risks are critical to manage in designing a MSPS compensation framework?**
2. **How can they best be managed?**

5.5 Regulatory and administrative burden

The probability of claims being made under each existing compensation framework (APP and directions) is relevant when considering the administrative efficiency of each framework, and thus the desirability of applying either framework (or some other framework) to MSPS periods.

The relative ease or complexity of seeking compensation, and the costs to claimants associated with the process, are factors that will influence generator decisions during MSPS periods as to whether they will voluntarily contribute to system restoration/maintenance or await a direction. Another important consideration in designing a compensation framework is mitigating the administrative and compensation costs passed through to consumers.

A key point of difference between the existing frameworks is that, under the directions compensation framework, the calculation of compensation for directed participants is – in the first instance – automatic. The majority of participants to whom a direction has been issued have not sought additional compensation.

119 Available at https://www.aemc.gov.au/sites/default/files/content/e6608852-6629-4732-ac19-f932d00545f1/Origin-Energy-nbsp%3B-received-21-July-2010.PDF

By contrast, there is no element of automation in the APP compensation framework. This means that the administrative burden associated with processing such claims is higher, all else being equal, than it is for directions compensation (since a base level of compensation is automatically determined in the directions compensation framework).

In addition, there is no process under the APP compensation framework for using prior decisions to inform later claims. This contrasts with the directions compensation framework under which a fair payment price determined by an independent expert is to be applied to any directions relating to that service issued within 12 months of the date of the independent expert's determination.[120] Under the APP framework, there is no opportunity to leverage expert advice and apply it to more than one claim.

The timetable for processing compensation claims is set out in the table at Appendix A. Under the APP compensation framework, the AEMC is to make a final decision on direct cost only claims (i.e. not including any opportunity costs) within 45 business days from the date that the assessment formally commenced (i.e. once the AEMC has sufficient information from the claimant). For claims including both direct and opportunity costs, the AEMC is to make a decision around 90 business days after formal commencement. However, in both cases, the AEMC may extend these timeframes if this is considered reasonably necessary due to complexity or if there is a material change in circumstances.[121]

This contrasts with the timeframes set out in the intervention settlement timetable for finalising directions compensation payments. Under that timetable, the provisional determination of compensation based on the 90th percentile price or fair payment price (if already established) occurs 23 business days after the end of the billing week in which the direction was issued, while the longest period for settling the most complex claims is 200 business days (or around 40 weeks). There is no discretion to extend these timeframes, and the intervention settlement timeframes run from the date of the direction (or relevant billing week) ending, rather than the time at which it is decided that the claimant has provided sufficient information.

The AEMC may recover from a claimant any costs incurred by the AEMC in carrying out their functions under clause 3.14.6 of the Rules (regarding APP compensation claims). If costs are to be recovered, the AEMC may require the claimant to pay all or a proportion of those costs prior to the claim being considered or determined. By contrast, there are no fees payable to AEMO when lodging a claim for additional compensation and the initial payment of compensation (based on 90th percentile or fair payment price) is automatic, entailing no cost to directed participants.

While AEMO deals with a growing number of compensation claims and has systems in place to support this (particularly with respect to the automated component of the framework), the AEMC has only had to process one compensation claim since the commencement of the NEM. The level of organisational experience of the responsible market body has implications for the administrative efficiency of the proposed MSPS compensation framework, as does the potential for duplication or "forum shopping" where more than one compensation framework is applicable.

120 NER, clause 3.15.7A(e)

121 NER, clause 3.14.6(t)

AEMO's budget is funded by market participants (and ultimately consumers), while the AEMC's budget is funded by states and territories (and ultimately taxpayers). Developing an optimally efficient compensation framework is important in order to minimise price impacts on consumers, consistent with the NEO, and costs to the tax base, consistent with best practice regulatory efficiency principles.

Issue 6 Administering the compensation framework

1. **How could the design of the MSPS compensation framework minimise regulatory and administrative burdens on market participants, market bodies and consumers?**
2. **Which organisation should administer the compensation framework?**
3. **What timeframes should govern the compensation framework?**
4. **How should administrative costs be recovered?**

6 Lodging a submission

The Commission has published a notice under s. 95 of the NEL for this rule change proposal inviting written submission. Submissions are to be lodged online or by mail by **Thursday, 14 June 2018** in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on rule change requests.[122] The Commission publishes all submissions on its website subject to a claim of confidentiality.

A template is available to help stakeholders provide their views on the issues raised in this paper.[123]

All enquiries on this project should be addressed to Katy Brady on (02) 8296 0634.

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0225. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

6.2 Lodging a submission by mail

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

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

The envelope must be clearly marked with the project reference code ERC0225.

122 This guideline is available on the Commission's website www.aemc.gov.au

123 Available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AFP	Administered Floor Price
APC	Administered Price Cap
APP	Administered Price Period
Commission	See AEMC
CPT	Cumulative Price Threshold
MSPS	Market Suspension Pricing Schedule
MSPS period	period when the MSPS applies
MSTWG	Market Suspension Technical Working Group
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules
NSP	Network Service Provider
Rules	See NER
SRMC	Short Run Marginal Cost

Appendix A: Comparison of administered price period and directions compensation frameworks

Elements of compensation framework	Directions Compensation Framework	Relevant NER clause	Administered Price Periods compensation framework	Relevant NER clause
Objective of compensation	While the directions compensation framework does not have a stated objective, the practical effect of the framework is to enable directed parties to recover their costs, and to put affected parties in the position that they would have been in but for the direction. (As noted in section 5.2.3, some have suggested that articulating a clear objective would be beneficial.)		To maintain the incentive, during price limit events, for • Generators (scheduled and non-scheduled) and scheduled NSPs to supply energy • ancillary service providers to supply ancillary services, and • market participants with scheduled load to consume energy	3.14.6(c)
Who can claim compensation?	Directed Participants – for the provision of a service pursuant to a direction (energy, market ancillary services or system security), and Affected Participants – to put affected participants in the position they would have been in but for the direction. Directed participants are defined as a Scheduled Generator, Semi-Scheduled Generator, Market Generator, Market Ancillary Service Provider, Scheduled Network Service Provider or Market Customer the subject of a direction. Affected participants are defined as: (1) a Scheduled Generator or Scheduled Network Service Provider: (i) which was not the subject of the direction, that had its dispatched quantity affected by that direction; or (ii) which was the subject of the direction, that had its dispatched quantity for other generating units or other services which were not the subject of that direction affected by that direction, however, the Scheduled Generator or Scheduled Network Service Provider is only an Affected Participant in respect of those generating units and services which were not the subject of that	3.15.7	• Generators (scheduled or non-scheduled) in the relevant region • A market participant in respect of a scheduled load dispatched in the relevant region in the eligibility period • A scheduled NSP that transported power towards the relevant region • An Ancillary Service Provider that provided market ancillary services in the relevant region in the eligibility period provided in each case that the claimant has incurred total costs during the eligibility period that exceed the total revenue it received from the spot market during that period. Relevant region is defined as the region in which prices are set by the 'price limit event'. For ancillary service providers, the price limit event is the application of the APC (meaning that they are not eligible to claim compensation for losses due to scaling). For all other parties, the price limit event includes both the direct effect of the APC and the secondary effects of scaling in neighbouring regions.	3.14.6(b)

Elements of compensation framework	Directions Compensation Framework	Relevant NER clause	Administered Price Periods compensation framework	Relevant NER clause
	direction; or (2) an eligible person entitled to receive an amount from AEMO pursuant to clause 3.18.1(b)(1) where there has been a change in flow of a directional interconnector, for which the eligible person holds units for the intervention price trading interval, as a result of the direction.			
How is compensation calculated?	For directed participants, compensation is paid based on the 90th percentile price (for the preceding 12 months in the region in which the direction was given) for the energy or ancillary service provided pursuant to the direction.	3.15.7(c)	The amount of compensation payable must be based on direct and opportunity costs, having regard for the AEMC compensation guidelines. Each claim is assessed on a case by case basis.	3.14.6(d) and (e)
	For services other than energy and market ancillary services, compensation is based on 'the fair payment price' determined by an independent expert in acc. with clause 3.15.7A.	3.15.7A		
	Directed participants can claim for additional compensation if their net direct costs and lost revenue exceed the compensation based on the 90th percentile price or fair market price (but only if the claim in respect of a single intervention price trading interval exceeds $5,000).[124]	3.15.7B		
	Affected participants are entitled to receive from AEMO, or must pay to AEMO, an amount reflecting the position that the affected participant would have been in had the direction not been issued (but there is no entitlement to compensation, or obligation to pay, if the amount is less than $5,000). Market customers are entitled	3.12.2		

124 The AEMC understands that AEMO may submit a further rule change request to apply this $5,000 threshold to an entire intervention event (e.g. the period of time that a direction is in place), rather than to each trading interval within the intervention event (on the basis that the current approach reduces the ability of a directed participant to recoup its losses). See section 5.3.4.

Elements of compensation framework	Directions Compensation Framework	Relevant NER clause	Administered Price Periods compensation framework	Relevant NER clause
	to receive an amount calculated in accordance with clause 3.12.2(a)(2) - again subject to the $5,000 per intervention price trading interval threshold.			
Can you claim direct costs?	Yes: clauses 3.15.7B(a)(1) and (a1) refer to additional net direct costs. Examples of such costs are set out in clause 3.15.7B(a3)	3.15.7B(a)(1) and (a1)	Yes – clause 3.14.6 refers to direct costs. While the clause does not refer to 'net direct costs' (as in the case of directions compensation), the concept of net costs is covered by the proviso in clause 3.14.6(b) that a compensation claimant must incur total costs during the eligibility period that exceed the total revenue it received from the spot market during that period.	3.14.6(b) and (d)
Can you claim other costs?	Yes: clauses 3.15.7B(a)(1) and (a1) refer to loss of revenue (as well as additional net direct costs – see above) incurred as a result of the provision of the service under direction. (Further information regarding what this includes is not included in the same way as it is for additional net direct costs.)	3.15.7B(a)(1) and (a1)	Eligible claimants can claim opportunity costs ('the value of opportunities foregone by the claimant due to the price limit event as defined in the compensation guidelines').	3.14.6(d) and (a) – definition of opportunity costs
	There is also provision to claim a reasonable rate of return on capital (but only when AEMO has determined that it is not reasonable to expect an independent expert to determine, within a reasonable period, a fair payment price for directed services other than energy and ancillary services).	3.15.7B(a1)(2)		
Relevant period for calculating compensation	Compensation is calculated based on the period during which services are provided under the direction.	3.15.7, 7A and 7B	The eligibility period for compensation starts at the beginning of the trading interval in which the price limit event occurs and ends at the end of that trading day. This means that compensation is calculated on a daily basis, even if the administered price period extends over a number of days.	3.14.6(a) and (b)
Process for making claim	Compensation based on the 90th percentile price is calculated automatically by AEMO – there is no need for a directed	3.15.7	Claimant provides a written notice to AEMC and AEMO in the form required by the compensation guidelines.	3.14.6(h) and (i)

Elements of compensation framework	Directions Compensation Framework	Relevant NER clause	Administered Price Periods compensation framework	Relevant NER clause
	participant to make a claim for this amount.			
	If a directed participant wishes to claim additional compensation (ie. beyond the compensation based on the 90th percentile price), it must - in a written submission to AEMO - itemise and substantiate each cost component.	3.15.7B(b)		
	Affected participants and market customers need not lodge a claim – AEMO must calculate amounts owed in accordance with clause 3.12.2(c). However they can then dispute AEMO's determination by lodging a submission itemising each component of the claim: clause 3.12.2(f)	3.12.2		
Who processes claim?	Claims are made to AEMO which determines if the claim is reasonable and, if so, pays the amount claimed.	3.15.7B(c)(2)	Claims are processed by the AEMC but compensation is paid by AEMO. The guidelines allow the AEMC to draw on external expertise if required.	3.14.6(h)
	Claims for additional compensation are referred to an independent expert if the amount of the claim exceeds certain thresholds, being $20,000 for the individual claim and $100,000 for the sum of claims (relating to the same event) by affected and directed participants and market customers.	3.15.7B(c)(1)		
	Claims are also referred to independent experts in the event that AEMO determines that the claim is unreasonable.	3.15.7B(d)		
Timeframes for making a claim	• The settlements timeframe is set out in the 'intervention settlement timetable'. • Compensation based on the 90th percentile price is provisionally determined 23 business days after the end of the billing week in which the direction was issued by AEMO. • If claims for additional compensation are made, time limits for	3.12.1 and Intervention Settlement Timetable	• Claim must be made within 5 business days of the APP ending. • Once AEMC has relevant information, it must as soon as reasonably practicable publish a notice that it has formally commenced its assessment. • For direct cost only claims, AEMC must publish final decision	3.14.6 paras (h) - (t)

Elements of compensation framework	Directions Compensation Framework	Relevant NER clause	Administered Price Periods compensation framework	Relevant NER clause
	settling these range from 100 business days after the end of the intervention event (in cases where no independent expert is required), to 200 business days (if the independent expert is required to determine a more complex claim).		re whether compensation should be paid, and quantum, not later than 45 business days after the formal commencement notice. • For claims that include opportunity costs, AEMC must – not later than 35 business days after the notice – publish the claimant's and the AEMC's proposed methodologies for assessing opportunity costs and invite submissions (due not less than 20 business days later). • Not later than 35 business days after submissions close, AEMC must publish final decision on methodology used and amount of compensation payable. • Thus, a total of 45 business days from publication of notice (to occur as soon as practicable after AEMC has sufficient information from claimant) to final decision for direct cost only claims, and around 90 business days between publication of notice and final decision for claims including opportunity costs, however… • AEMC may extend these timeframes if this is considered reasonably necessary due to the complexity or difficulty of assessing the claim or because of a material change in circumstances.	
Recovery of compensation costs	Compensation payments are funded by market participants having regard for the relative benefit each region receives as a result of the direction.	3.15.8	Compensation payments by AEMO are funded by each market customer who purchased electricity in the region in which the administered price cap or administered floor price applied.	3.15.10
Recovery of admin costs	There is no fee for lodging a claim. The cost to AEMO of processing claims is recovered via its budget (which is funded by market participants). The cost of engaging independent experts is recouped from market customers, along with the cost of the compensation payment.	3.15.8	AEMC has discretion to recover its costs from the claimant (but has not done so in the one compensation claim lodged to date). The cost to the AEMC of processing that claim was recovered via its budget (which is funded by the states and territories).	3.14.6(v)

Elements of compensation framework	Directions Compensation Framework	Relevant NER clause	Administered Price Periods compensation framework	Relevant NER clause
How frequent are claims?	Multiple claims have been made and paid – esp in recent times. Of the occasions when directions have been issued, only around 15% have involved claims for additional compensation (beyond that calculated automatically by AEMO).	N/A	Has only occurred once – in 2009 (claim by Synergen).	N/A
Is the process transparent?	Somewhat – AEMO publishes its own report and independent expert reports as to the quantum of compensation payable. The identity of the directed participant/compensation claimant is not disclosed and no confidential information is published – see for example 3.12.3(c)(5). Market notices also do not disclose the identity of directed participants. Clause 3.15.7A(c)(5) states that independent expert reports must not disclose the identity of the directed participant, but this appears to be the only such prohibition. There is no such restriction on AEMO in publishing its report after issuing a direction (clause 3.13.6A).	3.12.3(c)(5) 3.13.6A 3.15.7A(c)(5)	Somewhat – AEMC determination is public and identity of claimant is known but claimant may assert that information provided is confidential. The quantum of the Synergen compensation claim was public, but not the elements making up this quantum.	3.14.6(e) 3.14.6(j)(1) 3.14.6(l) 3.14.6(o) 3.14.6(q) Comp. Guidelines, section 1.7