RULE

Australian Energy Market Commission

RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (PARTICIPANT COMPENSATION FOLLOWING MARKET SUSPENSION) RULE 2018

PROPONENT

AEMO

15 NOVEMBER 2018

INQUIRIES

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ABOUT THE AEMC

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

SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has made a final rule which introduces a new compensation framework for market suspension events.

2 Market suspension events have occurred twice since the National Electricity Market (NEM) began in 1998. The first event resulted from an IT system failure in April 2001 and lasted two hours. The second occurred in September 2016 following the black system event in South Australia (SA). That event lasted nearly two weeks and highlighted a number of issues with the framework for managing market suspensions, including the lack of any means (other than the directions compensation framework) to compensate participants who incur loss when prices in the Market Suspension Pricing Schedule (MSPS) are low. (The MSPS is a schedule of average prices, based on prices in the preceding four weeks, that is used to set prices during a market suspension when normal pricing processes are not operating.)

3 If participants are not appropriately compensated for operation by prices in the MSPS, they may seek to be directed in order to be compensated under the directions compensation framework. Issuing directions involves a complex process and, if directions are needed during a market suspension (as occurred towards the end of the SA market suspension), this creates additional work at a time of already heightened control room stress.

4 The final rule amends the National Electricity Rules (NER) to create a framework for compensating market participants who incur loss when, during a market suspension event, spot and ancillary service prices are set by the MSPS.

5 The final rule, which is a more preferable rule, was made in response to a request submitted by the Australian Energy Market Operator (AEMO) following the SA market suspension event. AEMO's objective in requesting the rule change was to remove the current incentive for generators to await a direction from AEMO (and be compensated under the relatively generous directions compensation framework) rather than provide services voluntarily when prices in the MSPS are too low to cover generator costs.

6 AEMO proposed that the compensation framework applicable to Administered Price Periods (APP) be extended so that it also applies to periods in which the MSPS operates - described in this final determination as 'MSPS periods'. Under the APP framework, a party that incurs loss can choose to make a bespoke claim to itemise and substantiate its costs. The APP compensation system is costly to administer and provides no predictability. Only one claim has been made under this framework since the inception of the NEM.

7 The Commission has decided instead to develop a compensation framework for MSPS periods that more closely reflects that applicable to directions. Under the directions framework, compensation is - in the first instance - automatically calculated based on the 90th percentile price. Claims for additional costs can also be made where necessary. Under the directions framework, both the automatic compensation and any additional compensation payments are recovered from market customers and thus are ultimately paid for by consumers.

8 The final rule creates a new compensation framework that is predictable and (relative to the APP model) administratively simple. There are however important differences between the

new framework and the directions compensation framework, particularly with respect to the amount of automatically calculated compensation. This reflects that the new compensation framework will apply to all eligible claimants during MSPS periods, whereas the directions compensation framework applies 'ex post' and only to those select few participants who have been directed by AEMO to provide services. (In the final rule, eligible claimants are referred to as 'market suspension compensation claimants' but, for brevity, are referred to in this determination as 'eligible claimants'.)

9 While two stakeholders suggested in response to the consultation paper that compensation under the MSPS framework should be based on the 90th percentile price (consistent with the directions compensation framework), the Commission has not adopted this approach. Instead, the final rule creates a framework that compensates generators by reference to the short run costs they are deemed to have incurred (referred to in this final determination as 'estimated costs'), thus reducing the risk that generators will be out of pocket when they provide services during a MSPS period.

10 Under the final rule, a scheduled generator or ancillary service provider that provides services during a MSPS period is automatically entitled to compensation if its estimated costs during the MSPS period (calculated using the applicable 'benchmark value') exceed the revenue it earns from the MSPS (see figure 1.1 on page vi which sets out how the compensation framework will be applied in the event of a market suspension). This creates incentives for eligible claimants to continue to participate in the market during a MSPS period while limiting the potential for inefficient bidding and dispatch outcomes. Such outcomes would lead to higher costs for consumers, who will ultimately bear the cost of compensation payments under the MSPS compensation framework.

11 The key features of the final rule are:

- compensation will automatically be payable to scheduled generators and ancillary service providers (in respect of ancillary service generating units that are also classified as scheduled generating units) if prices in the MSPS are not sufficient to cover their estimated costs. This recognises that, while AEMO has power to direct a wide range of market participants, it has only ever directed generators which are scheduled. Given that the objective of the rule change request is to remove the incentive for generators to withdraw and await direction where MSPS prices are low, the compensation framework focuses on scheduled generators as these are the parties who would typically be directed by AEMO in the event that they did not provide services voluntarily. Such parties are referred to as 'market suspension compensation claimants' in the final rule.
- compensation will be calculated based on pre-determined 'benchmark values': regionally averaged estimated short run marginal costs (SRMC) for generators in each category - e.g. black coal, brown coal, open cycle gas turbine, combined cycle gas turbine, hydro, large scale batteries, biomass, solar thermal - supplemented by a 15 per cent premium to account for divergences between estimated and actual costs
- if estimated costs (calculated using benchmark values) exceed market revenue earned based on the MSPS, compensation will be paid to cover the gap - thereby reducing the

risk that generators and ancillary service providers may incur loss due to low prices in the MSPS

- benchmark values will be calculated annually by AEMO using cost inputs developed for planning purposes in accordance with rule 5.20 of the NER (known as 'NTNDP inputs', these are used in developing the National Transmission Network Development Plan and, this year, the Integrated System Plan)
- the formula for calculating benchmark values is set out in the final rule, supported by the Market Suspension Compensation Methodology to be developed by AEMO; the methodology will also set out the categories of scheduled generators and ancillary service providers for whom benchmark values are to be determined
- if automatically calculated compensation is insufficient or, if no compensation is automatically payable and revenue earned under the MSPS is insufficient to cover a scheduled generator's or ancillary service provider's direct costs of participating in the market, that party will be able to seek additional compensation by lodging a claim with AEMO
- where a direction is issued to an eligible claimant during a MSPS period, the automatically calculated compensation for services provided pursuant to the direction will be determined using the MSPS benchmark value approach outlined above, rather than the 90th percentile price approach usually applicable to directions. This is designed to remove the residual risk that participants will withdraw and await direction (so as to maximise the amount of compensation they can receive) rather than work collaboratively with AEMO to restore and/or maintain supply during a market suspension. Where the automatically calculated compensation is insufficient to cover costs, directed participants who are also eligible claimants will be able to lodge a claim for additional compensation in the usual way (using the additional compensation provision in the directions compensation framework).
- following a MSPS period, AEMO will report publicly on the quantum of MSPS revenue and, if applicable, compensation paid to each eligible claimant, and the share of compensation costs payable by each Market Customer (as determined by AEMO under clause 3.15.8A)
- the transitional arrangements in the final rule will commence on 22 November 2018 and will require AEMO to develop and publish an interim Market Suspension Compensation Methodology and the first schedule of benchmark values by 19 December 2018. Once this methodology and schedule are in place, the remainder of the rule will commence on 20 December 2018. (This staged approach is necessary as the new compensation framework cannot operate without the required methodology being in place.) The first Market Suspension Compensation Methodology will be followed by a final methodology within a further six months. Preparation of the final methodology will be informed by consultation with stakeholders in accordance with the Rules consultation procedure. This consultation will focus on the methodological approach to be adopted, rather than on the NTNDP inputs, which are already subject to consultation requirements in clause 5.20.1.
- Schedule 2 of the final rule includes further amendments so that, when the five minute settlement rule commences on 1 July 2021, certain terms used in the MSPS

compensation framework (e.g. dispatch interval and dispatch price) will be updated to bring the framework into line with the new five minute settlement procedures.

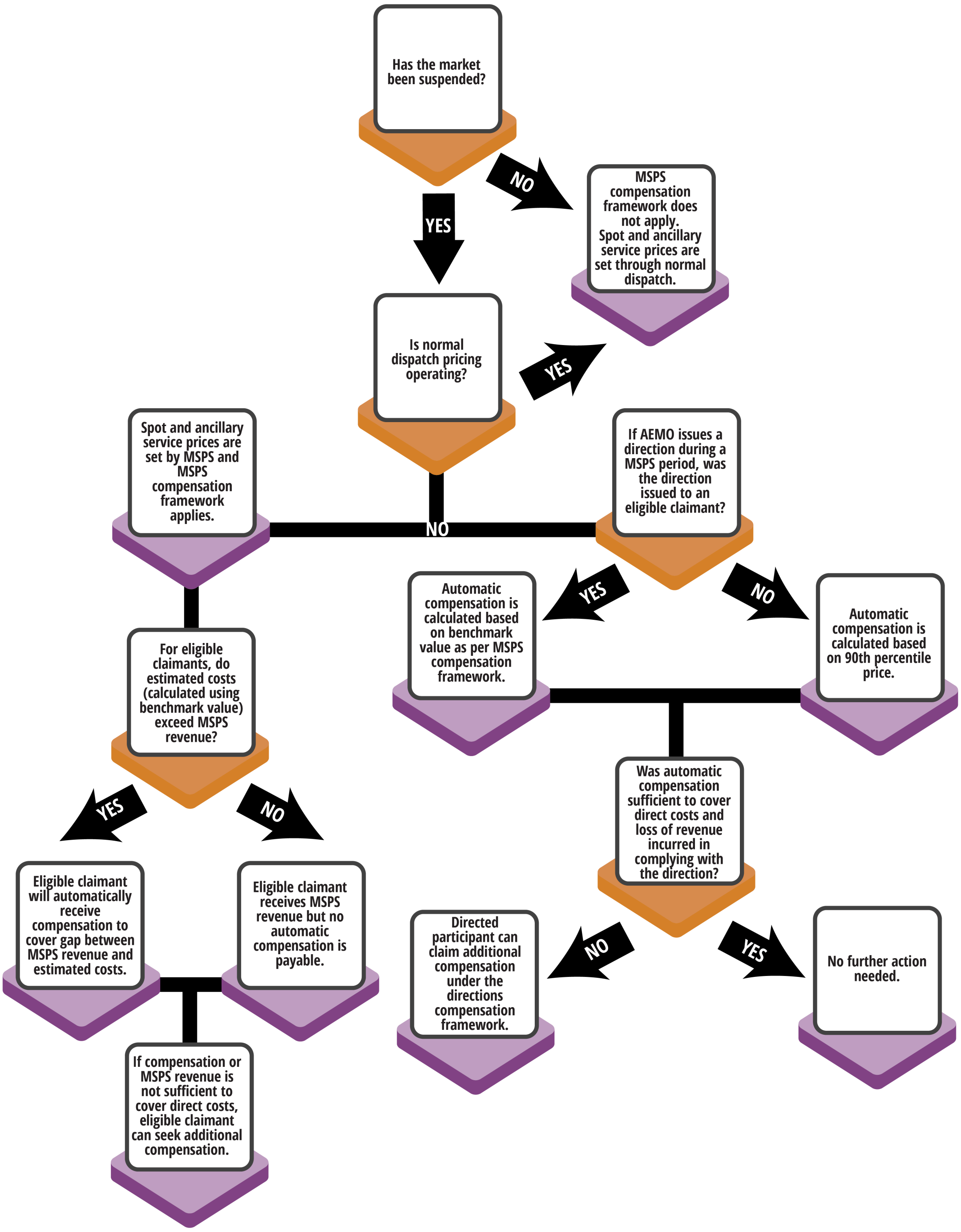
12 The final rule is the same as the draft rule save for four changes, summarised below and discussed further in chapter 4.

- The ten per cent premium has been increased to 15 per cent in recognition of the static nature of the heat rates included in the NTNDP inputs and the fact that, in practice, heat rates (and thus fuel costs per unit of energy produced) vary based on factors such as plant loading and ambient temperatures. In addition, it is recognised that actual and estimated fuel costs are likely to vary. Increasing the premium better accommodates such cost variations, thereby limiting the need for generators to seek additional compensation in order to recoup their losses. At the same time, setting the premium at this level limits the cost impacts on consumers that a higher premium would entail.
- Eligibility for compensation has been extended to include scheduled generators in neighbouring regions who incur loss due to price scaling. (Price scaling occurs when energy flows over a regulated interconnector towards a suspended region and the price in the suspended region is lower than the price would otherwise be in the exporting region. This is discussed further in section 4.5.1.) One submission in response to the draft determination noted the potential for generators in a neighbouring region (or regions) to bid unavailable and await direction in the event that prices are scaled as a result of the application of the MSPS, making the spot price in the neighbouring region/s too low to cover a generator's short run costs. The objective of AEMO's rule change request was to remove the current incentive for generators to withdraw in response to low prices and await direction. Consistent with this, and noting proposed changes to the way in which prices in the MSPS are to be determined, the final rule makes scheduled generators in neighbouring region/s eligible for compensation if they incur loss during those trading intervals that are impacted by scaling. During such intervals, if a generator's costs (estimated using benchmark values) exceed the revenue it earns based on the scaled price, compensation will automatically be payable to cover the gap. If automatically calculated compensation is not sufficient, a claim for additional compensation may be made.
- The final rule adjusts the cost recovery mechanism so that all costs are recovered through the directions framework (rather than through a mixture of the APP and directions framework cost recovery mechanisms). This will streamline the cost recovery process and is also more appropriate given the potential for compensation to be paid to generators in neighbouring regions who incur loss due to price scaling. (While the APP framework recovers costs solely from consumers in the region subject to the administered price cap, the directions framework recovers costs from consumers in accordance with the 'regional benefit test' - meaning the cost of compensation payments may be borne by consumers in more than one region.)
- The final rule confers discretion on AEMO to refer claims for additional compensation to an independent expert where such claims exceed $50,000 (making the provision discretionary rather than mandatory). This was in response to concern raised by two stakeholders regarding the additional cost that a claimant could be expected to incur (via

the administrative fee) if a claim for additional compensation is referred to an independent expert. One stakeholder suggested that a claim could exceed the threshold but still be straight forward. Rather than increase the threshold or apply it to a shorter period (e.g. a single trading day), the final rule makes the provision discretionary rather than mandatory, giving AEMO the flexibility to deal with larger claims in house, rather than an obligation to refer all claims in excess of $50,000 to an independent expert.

13 The Commission considers that the final rule achieves AEMO's objective, minimises the potential for perverse incentives that could lead to inefficient outcomes, and achieves a fair balance between the interests of market participants and consumers. As a result, the final rule will, or is likely to, contribute to achieving the National Electricity Objective as it promotes the reliability and security of the supply of electricity in the long term interests of consumers.

Figure 1.1: Market suspension pricing schedule compensation framework



Source: AEMC. Note that 'MSPS revenue' encompasses revenue earned when prices are scaled due to the application of the MSPS.

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1 INTRODUCTION AND BACKGROUND

1.1 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 sought to introduce participant compensation arrangements for electricity market suspension events, based on the compensation arrangements for administered price periods (APP).

The AEMC published a consultation paper on 17 May 2018 and a draft determination on 23 August 2018. This final determination set outs:

- a summary of, and background to, the rule change request
- a summary of the Commission's reasons
- an assessment of the issues identified in submissions.

1.2 Background to the rule change request

This section 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 framework for directions and APP.

1.2.1 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 occured on Wednesday 28 September 2016.[1]

As part of its investigation into the Black System event and subsequent 13 day 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 provided a number of recommendations in relation to this framework. These included a recommendation 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.[2]

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.[3] This process identified the need for two rule changes -

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

2 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.

3 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

one relating to pricing during market suspension and the other relating to participant compensation following market suspension.

1.2.2 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 the expedited process so that changes could be in place before the summer of 2017/18.

On 10 October 2017, the AEMC made a final rule that simplified the process for setting prices if the spot market is suspended. As a result of that rule change, AEMO can now set prices as normal using the National Electricity Market Dispatch Engine (NEMDE) where practicable[4] or, if this is not possible, set spot and ancillary service prices in accordance with the market suspension pricing schedule (MSPS - a schedule based on average prices over the preceding four weeks).[5]

This means that, if the market is suspended in the future and all else being equal, the period of time in which the MSPS applies may be shorter than the 13-day period during which the SA market was suspended in late 2016. This is based on the fact that, while the MSPS applied throughout the 13-day market suspension, NEMDE was used to set dispatch targets, though not prices, for the latter part of the market suspension period.[6]

Further information on the Pricing during market suspension rule change can be found on the AEMC website.[7]

1.2.3 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 final determination.

AEMO proposed that the compensation framework applicable to APP be extended so as to compensate participants whose costs are not recouped via the prices set out in the MSPS. This was designed to remove the incentive for market participants to minimise financial loss and await direction rather than voluntarily supporting the restoration or maintenance of the electricity system during a market suspension.

The market suspension in SA 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

4 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. See: clause 3.14.5(d)(3) .

5 The MSPS is developed pursuant to clause 3.14.5(e) of the NER which requires AEMO to prepare schedules containing 'reasonable estimates of typical market prices'. Clause 3.14.5(b) requires AEMO to set dispatch and ancillary service prices in accordance with the prices set out in the MSPS. Dispatch prices relate to five minute dispatch intervals, while spot prices apply to 30 minute trading intervals and are determined based on the time-weighted average of the dispatch prices in a single trading interval: NER, clause 3.9.1(2).

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

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

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.[8]

Until now, there has not been any provision in the NER to compensate market participants for net losses incurred when the MSPS applies.[9] However, market participants are entitled to compensation if directed by AEMO to provide services during a market suspension event. Until now, direction compensation has been the only avenue for participant compensation in respect of market suspension pricing.[10]

AEMO regards the use of directions as a last resort which should not be incentivised by the NER.[11] 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 market suspension. The process involves implementing counteractions (to minimise the number of affected participants, cost of compensation and impact on interconnector flows arising from the direction), and compensating both directed and affected participants.

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.[12] Accordingly, AEMO proposed that the current arrangements for compensating participants during an APP should be extended so that they 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 (via NEMDE). 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. Accordingly, the proposed framework is described in this final determination as the 'MSPS compensation framework'.

1.3 Market suspension framework in the NER

The current 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

8 AGL, Submission to Inquiry into State-wide blackout of Wednesday 28 September 2016, 14 February 2017, pp 18, 21 and 22

9 Historically, the NER provided limited provisions for market participants to claim compensation in relation to market suspension events but only where an APP coincided with a market suspension. See clause: 3.14.6(a) and (a2) as they stood in NER Version 58, current as at 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 - 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 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.

10 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 .

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

12 NER, clause 3.1.4(a)(1)

- clause 3.14.5: pricing during market suspension.

AEMO manages periods of market suspension in accordance with these provisions and having regard to its supporting operational procedures.[13] The market suspension framework incorporates a number of key components as set out in figure 1.1 and discussed in more detail below.

1.3.1 Conditions for suspension of the NEM spot market

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

1. the power system has collapsed to a black system
2. 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
3. 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) has occurred twice since commencement of the NEM in 1998:

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

1.3.2 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 below, 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.

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

Figure 1.1: Market suspension framework

Market suspension

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 determines 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.

Suspension pricing

AEMO has two options:

a. normal dispatch pricing
b. MSPS sets spot and ancillary service prices

AEMO can apply normal dispatch pricing at any time during a market suspension if

- in its reasonable opinion, it is practicable to resume central dispatch and pricing, and
- the market was suspended other than in response to a jurisdictional direction.

Where the market has been suspended due to a jurisdictional direction, AEMO can resume normal dispatch pricing if that jurisdiction agrees.

Inter-regional price scaling

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.

Dispatch mechanism

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 SA market suspension and has since published a high level procedure for future market suspensions.

Participant compensation

There is no provision in the rules to compensate market participants for net losses incurred as a result of the application of the MSPS.

However, market participants may be entitled to compensation if

- **directed by AEMO to provide services, or**
- **an APP 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

1.3.3 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 therefore differs from the rules that governed the market suspension in SA in late 2016.

Under the current rules, 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 rules 3.8 and 3.9 of the NER, this process should continue to be used. It allows for orderly bidding and dispatch, supporting efficient market outcomes[14]
2. **market suspension pricing schedule**: if, in AEMO's reasonable opinion, it is not practicable to operate central dispatch and pricing then AEMO must set dispatch and ancillary service 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.[15]

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.[16] The exception is where 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.[17]

1.3.4 Inter-regional price scaling

The NER 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.[18]

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.[19] The purpose of price scaling is to prevent, or manage, the accumulation of negative interregional settlement residues. During the SA market suspension, prices were scaled in Victoria, New South Wales and Queensland as a result of the application of the MSPS in SA.[20]

14 NER, clause 3.14.5(a)

15 NER, clauses 3.9.2(e)(5), 3.14.5(b) and 3.14.5(e). AEMO is making changes to the methodology used to develop the MSPS. See https://www.aemo.com.au/Stakeholder-Consultation/Consultations/Market-Suspension-Pricing-Consultation

16 NER, clause 3.14.5(a)

17 NER, clause 3.14.5(d)(3)

18 NER, clause 3.14.5(f)

19 NER, clause 3.14.5(f)

20 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. See: AEMO, *Black System South Australia 28 September 2016*, March 2017, p. 85

1.3.5 Dispatch during market suspension

If a market suspension is in effect, AEMO is required to follow normal dispatch procedures where possible,[21] 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 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 recent 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 NER.[22]

AEMO's final incident report for the Black System event in SA provides further detailed information on the framework for market suspension. Chapter 6 of that report provides a summary of the NER provisions related to market suspension and the sequence of events from the system shutdown to the lifting of the market suspension over the period 28 September to 11 October 2016.[23] It also includes a section on directions and compensation related to the Black System event.[24]

1.4 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[25] and in the event a participant incurs loss during an APP.[26] The NER do not contain provisions for participant compensation in relation to MSPS periods. Through this rule change request, AEMO sought to introduce participant compensation arrangements for MSPS periods based on the compensation arrangements for APP.

1.4.1 Process for issuing and determining compensation due to directions

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

21 NER, clause 3.14.5(a)

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

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

24 Ibid, Section 6.4, pp 85-86

25 NER, clauses 3.15.7, 3.15.7A and 3.15.7B

26 NER, clause 3.14.6

- minimise the likely cost of, and compensation flowing from a direction, as well as the number of affected participants and effects on interconnector flows[27]
- apply the regional reference node test; namely, intervention pricing is invoked if a direction to a generator affects a whole region[28]
- if appropriate, apply a 'what if' scenario (i.e. what would have happened if the direction had not been issued?) to determine the dispatch price for the dispatch interval/s in which the direction occurs[29]
- publish the 'intervention settlement timetable' setting out the process and timeframes for determining compensation payable to directed participants and participants affected by the direction[30]
- 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[31]
- compensate directed participants for services other than energy and ancillary services based on a fair payment price to be determined by an independent expert[32]
- 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)[33]
- adjust payments to or from affected participants so as to put them in the position 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)[34]
- recover any net compensation amounts from market customers in the region(s) for whose benefit the direction was issued.[35]

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.[36]

In most cases, directions have been issued in order to boost system security - for example, ensuring compliance with system strength requirements in SA. Directions have generally been issued in periods when low spot prices have prevented higher cost generators from recouping their short run marginal costs. Very few directions have been issued in order to ensure system reliability - reflecting that, when the supply demand balance is tight, spot

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

28 Intervention pricing is also known as 'what if' pricing - i.e. 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).

29 NER, clause 3.9.3(b)

30 NER, clause 3.12.1

31 NER, clause 3.15.7(c)

32 NER, clause 3.15.7A

33 NER, clause 3.15.7B

34 NER, clauses 3.12.2 and 3.12.3

35 NER, clause 3.15.8

36 Directions were issued on one occasion in each of 2013 and 2014, none in 2015, four in 2016, and 14 in 2017. As at 26 September 2018, nearly 150 directions have been issued in 2018: see further at https://www.aemo.com.au/Electricity/National-Electricity-MarketNEM/Market-notices-and-events/Market-event-reports

prices rise and enable most generators to recover their costs meaning no direction is required.[37]

In around 85 per cent of cases, directed participants have been compensated based on the 90th percentile price and have not claimed additional compensation.

1.4.2 Process for determining compensation due to the application of an APP

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.[38] 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 $216,900), an administered price cap of $300/MWh is imposed, together with an administered floor price of -$300/MWh.[39] This APP 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.[40]

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.[41]

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). The AEMC processes compensation claims relating to APP,[42] while AEMO deals with directions-related compensation applications.[43] In both cases, AEMO is responsible for arranging the actual payment of compensation and the recovery of costs from market customers.[44]

The objective of the APP 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.[45] 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.

37 At the time of writing, only two directions since 2010 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/InterventionPricing-Working-Group

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

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

40 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.

41 AEMC, ibid, p. i

42 NER, clause 3.14.6(j)

43 NER, clauses 3.15.7, 3.15.7A and 3.15.7B

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

45 NER, clause 3.14.6(c)

In summary, the APP compensation framework:

- allows market participants to claim compensation if they incur net loss over an eligibility period;[46] this is based on whether total costs (direct and opportunity) exceed total revenue from the spot market during the eligibility period[47]
  - **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 (the region subject to the APC)[48]
- references the AEMC's compensation guidelines which are used to inform participants of the process and assessment criteria for compensation.[49]

APP have occurred five times in the energy market since the inception of the NEM in 1998.[50] This reflects that high spot prices in the NEM are rarely sustained long enough to exceed the cumulative price threshold.[51] 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.[52] 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 capped in the energy market.[53]

The first ever APP triggered in an ancillary services market occured in October 2015. Over October and November 2015, several APPs occured in SA and applied only in ancillary service markets.[54] 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

46 '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.

47 NER, clause 3.14.6(b)

48 NER, clause 3.15.10(a1)

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

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

51 The cumulative price threshold can be triggered in different ways. For example, it could be triggered after seven days of sustained high but not extreme prices (averaging $646/MWh). It can also be breached in around 8 hours if prices are at or close to the market price cap (currently $14,500/MWh).

52 NER, clause 3.14.2(d1)

53 NER, clause 3.14.2(d2)

54 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

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.[55]

Further APP occured in the SA ancillary services market during 2016 and early 2017. Since the ancillary service market has diversified in SA, Frequency Control Ancillary Service (FCAS) prices have fallen and no APP have occured since April 2017.[56] Despite the number of APP in ancillary service markets, there have been no claims for compensation in relation to ancillary services provided during APP.

There has only been one claim for compensation arising from APP in the history of the NEM. This was the claim by Synergen that followed the APP in the SA 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.[57]

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 AEMO Reliability Panel indicates that, at present, all generators - even the highest cost open cycle gas turbine (OCGT) - have short run marginal costs of less than $300/MWh.[58]

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 from claimants when determining a claim for compensation under the APP framework.[59]

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

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

56 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.

57 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.

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

59 NER, clause 3.14.6(v)

claim, the external costs of processing the claim for compensation, namely the Panel's costs, will be shared equally with the claimant.[60]

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'.[61]

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 APP 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 likely 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 APP 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.[62]

1.4.3 Interactions between NER compensation frameworks

It is possible that multiple compensation frameworks in the NER could be triggered at the same time. For example, clause 3.14.5(c)(1) of the NER makes clear that an APP can be triggered when the market is suspended and the MSPS applies. It is also possible that a direction could be issued during an APP that coincides with a MSPS period.

The NER appear to contemplate that claims could be made under more than one framework[63] but do not include a formal mechanism to coordinate multiple claims and manage the risk of 'forum shopping'. Rather, this risk is to be 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

60 AEMC, *Final Decision, Compensation Claim from Synergen Power Pty Ltd*, 8 September 2010, pp 14-15

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

62 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

63 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'.

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'.[64]

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.'[65]

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

65 Ibid, p 13

2 AEMO'S RULE CHANGE REQUEST

2.1 The rule change request

On 25 July 2017, AEMO requested the AEMC to make a rule to introduce participant compensation arrangements for electricity market suspension events (the 'rule change request').

2.2 Rationale for the rule change request

In its rule change request, AEMO provided its rationale for the rule change.[66] A number of key points are summarised below:

- in the current 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 APP and directions[67]
- 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 NER. The administration of directions is complex and resource intensive, and can also have undesirable market outcomes.

The points above were illustrated by the 2016 SA 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.[68]

AEMO notes that, in the Black System event, all participants worked with AEMO to bring the system 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.[69] AEMO also notes that, during a market suspension, control room operators should be focussed on restoring the market to a safe and stable operating condition rather than considering whether to issue directions.[70]

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

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

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

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

2.3 The proposed rule

AEMO considered that there are parallels between the application of an APC and the application of the MSPS. For this reason, it proposed the same form of compensation for the same categories of participants. A compensation framework would provide a mechanism whereby participants would not be disadvantaged by continuing to participate in the market during high stress periods.[71]

The rule change request included a proposed rule, although some aspects of the proposed rule need to be updated to reflect the *Pricing during market suspension* rule change.[72] 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)
- clause 3.15.10A (which deals with GST in relation to APC compensation payments and other payments).

A copy of the rule change request may be found on the AEMC website at www.aemc.gov.au.

2.4 The rule making process

On 17 May 2018, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request.[73] A consultation paper identifying specific issues for consultation was also published. The Commission received six submissions in response to the consultation paper. The Commission considered all issues raised by stakeholders in submissions. Issues raised are discussed and responded to throughout this final rule determination, and are also summarised in Appendix A.

On 23 August 2018, the Commission published a draft rule determination and draft rule. Submissions on the draft rule determination closed on 4 October 2018. The Commission received four submissions to the draft determination and draft rule. The Commission considered the issues raised by stakeholders in submissions. These are discussed and responded to throughout this final rule determination. Issues that are not discussed in the body of this determination are summarised and responded to in Appendix B.

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

71 ibid

72 Specifically, references in the rule change request to various provisions within NER clause 3.14.5 are no longer accurate due to the clause being re-written for the Pricing during market suspension rule change.

73 This notice was published under s. 95 of the National Electricity Law (NEL).

3 FINAL RULE DETERMINATION

3.1 The Commission's final rule determination

The Commission's final rule determination is to make a more preferable final rule. The final rule creates a new compensation framework that automatically compensates scheduled generators and ancillary service providers (in respect of ancillary service generating units that are classified as scheduled generating units) whose estimated costs exceed revenue earned from prices in the MSPS (or where prices are scaled in neighbouring regions due to the MSPS). Where automatic compensation is not sufficient to cover losses, eligible claimants may seek additional compensation by lodging a claim with AEMO.

The Commission's reasons for making this final rule determination are set out in section 3.4.

This chapter outlines:

- the rule making test for changes to the NER
- the more preferable rule test
- the assessment framework for considering the rule change request
- the Commission's consideration of the final rule against the national electricity objective.

Further information on the legal requirements for making this final rule determination is set out in Appendix C.

3.2 Rule making test

3.2.1 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).[74] This is the decision making framework that the Commission must apply.

The NEO is:[75]

> 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.

3.2.2 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.

74 Section 88 of the NEL.

75 Section 7 of the NEL.

In this instance, the Commission has made a more preferable rule for the reasons sets out in section 3.4. The more preferable rule is referred to throughout this determination as the 'final rule'.

3.2.3 Making a differential rule

Under the Northern Territory legislation adopting the NEL, the Commission may make a differential rule if, having regard to any relevant MCE statement of policy principles, a different rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule. A differential rule is a rule that:

- varies in its term as between:
  - the national electricity system, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

As the rule relates to parts of the NER that currently do not apply in the Northern Territory, the Commission has not assessed the rule against the additional elements required by the Northern Territory legislation.[76]

3.3 Assessment framework

In assessing the rule change request against the NEO the Commission has considered the following principles:

- **effect on incentives**: whether the rule will incentivise market participants to help restore or maintain a reliable and secure electricity supply during market suspension while not encouraging inefficient bidding and dispatch outcomes
- **transparency and predictability**: whether the rule provides clear and predictable arrangements for compenstion during a market suspension event when the MSPS applies, thereby facilitating efficient decisions by participants
- **risk management**: whether the rule improves the ability of market participants and market bodies to manage risks during and after market suspension periods
- **regulatory and administrative burden**: whether the benefits of the rule are proportional to the regulatory and administrative burden on market bodies and participants, and costs passed onto consumers.

3.4 Summary of reasons

The final rule made by the Commission is attached to and published with this final rule determination. The framework set out in the final rule provides that a scheduled generator or

76 From 1 July 2016, the NER, as amended from time to time, apply in the NT, subject to derogations set out in regulations made under the NT legislation adopting the NEL. Under those regulations, only certain parts of the NER have been adopted in the NT. (See the AEMC website for the NER that applies in the NT.) National Electricity (Northern Territory) (National Uniform Legislation) Act 2015.

ancillary service provider that provides services during a MSPS period is automatically entitled to compensation if its estimated costs during the MSPS period (calculated using the applicable 'benchmark value') exceed the revenue it earns from the MSPS (or the price in a neighbouring region if that price is scaled due to the application of the MSPS).

The key features of the final rule are:

- compensation will automatically be payable to scheduled generators and ancillary service providers (in respect of ancillary service generating units that are classified as scheduled generating units) if prices in the MSPS are not sufficient to cover their estimated short run costs. This recognises that, while AEMO has power to direct a wide range of market participants, it has only ever directed generators which are scheduled (as well as two instances when directions were issued to Basslink). Given that the objective of the rule change request is to remove the incentive for generators to withdraw and await direction where MSPS prices are low, the compensation framework focuses on scheduled generators as these are the parties who would typically be directed by AEMO in the event that they did not provide services voluntarily. Such parties are referred to as 'market suspension compensation claimants' in the final rule but, for brevity, are referred to in this determination as 'eligible claimants'
- compensation will be calculated based on pre-determined 'benchmark values': regionally averaged estimated short run marginal costs (SRMC) for generators in each category - e.g. black coal, brown coal, open cycle gas turbine, combined cycle gas turbine, hydro, large scale batteries, biomass, solar thermal - supplemented by a 15 per cent premium to account for divergences between estimated and actual costs
- if estimated costs (calculated using benchmark values) exceed revenue earned based on the MSPS, compensation will be paid to cover the gap - thereby reducing the risk that generators and ancillary service providers may incur loss due to low prices in the MSPS
- benchmark values will be calculated annually by AEMO using cost inputs developed for planning purposes in accordance with rule 5.20 of the NER (known as 'NTNDP inputs', these are used in developing the National Transmission Network Development Plan and, this year, the Integrated System Plan)
- the formula for calculating benchmark values is set out in the final rule, supported by the Market Suspension Compensation Methodology to be developed by AEMO; the methodology will also set out the categories of scheduled generators and ancillary service providers for whom benchmark values are to be determined
- if automatically calculated MSPS compensation is insufficient or, if no compensation is automatically payable and revenue earned under the MSPS is insufficient to cover a scheduled generator's or ancillary service provider's direct costs of participating in the market, that party will be able to seek additional compensation by lodging a claim with AEMO
- where a direction is issued to an eligible claimant during a MSPS period, the automatically calculated compensation for services provided pursuant to the direction will be determined using the MSPS benchmark value approach outlined above, rather than the 90th percentile price approach set out in clause 3.15.7 that is usually applicable to

directions. This is designed to remove the residual risk that participants will withdraw and await direction (so as to maximise the amount of compensation they can receive) rather than work collaboratively with AEMO to restore and/or maintain supply during a market suspension. Where the automatically calculated compensation is insufficient to cover costs, directed participants who are also eligible claimants will be able to lodge a claim for additional compensation in the usual way (using the additional compensation provision in the directions compensation framework rather than the equivalent provision in the MSPS compensation framework)

- following a MSPS period, AEMO will report publicly on the quantum of MSPS revenue and, if applicable, compensation paid to each eligible claimant, and the share of compensation costs payable by each Market Customer (as determined by AEMO under clause 3.15.8A).
- the transitional arrangements in the final rule will commence on 22 November 2018 and will require AEMO to develop an interim Market Suspension Compensation Methodology and the first schedule of benchmark values by 19 December 2018. Once this methodology and schedule are in place, the remainder of the rule will commence on 20 December 2018. (This staged approach is necessary as the new compensation framework cannot operate without the required methodology being in place.) The first Market Suspension Compensation Methodology will be followed by a final methodology within a further six months. Preparation of the final methodology will be informed by consultation with stakeholders in accordance with the Rules consultation procedure. This consultation will focus on the methodological approach to be adopted, rather than on the NTNDP inputs, which are already subject to consultation requirements in clause 5.20.1.
- Schedule 2 of the final rule includes further amendments so that, when the five minute settlement rule commences on 1 July 2021, certain terms used in the MSPS compensation framework (e.g. dispatch interval and dispatch price) will be updated to bring the framework into line with the new five minute settlement procedures.[77]

The final rule is the same as the draft rule save for four changes, summarised below and discussed further in chapter 4:

- The ten per cent premium has been increased to 15 per cent in recognition of the static nature of the heat rates included in the NTNDP inputs and the fact that, in practice, heat rates (and thus fuel costs per unit of energy produced) vary based on factors such as plant loading and ambient temperatures. In addition, it is recognised that actual and estimated fuel costs are likely to vary. Increasing the premium better accommodates such cost variations, thereby limiting the need for generators to seek additional compensation in order to recoup their losses. At the same time, setting the premium at this level limits the cost impacts on consumers that a higher premium would entail.
- Eligibility for compensation has been extended to include scheduled generators in neighbouring regions who incur loss due to price scaling. (Price scaling occurs when energy flows over a regulated interconnector towards a suspended region and the price in the suspended region is lower than the price would otherwise be in the exporting

77 For further information see AEMC, *Rule Determination: National Electricity Amendment (Five Minute Settlement) Rule 2017*, November 2017

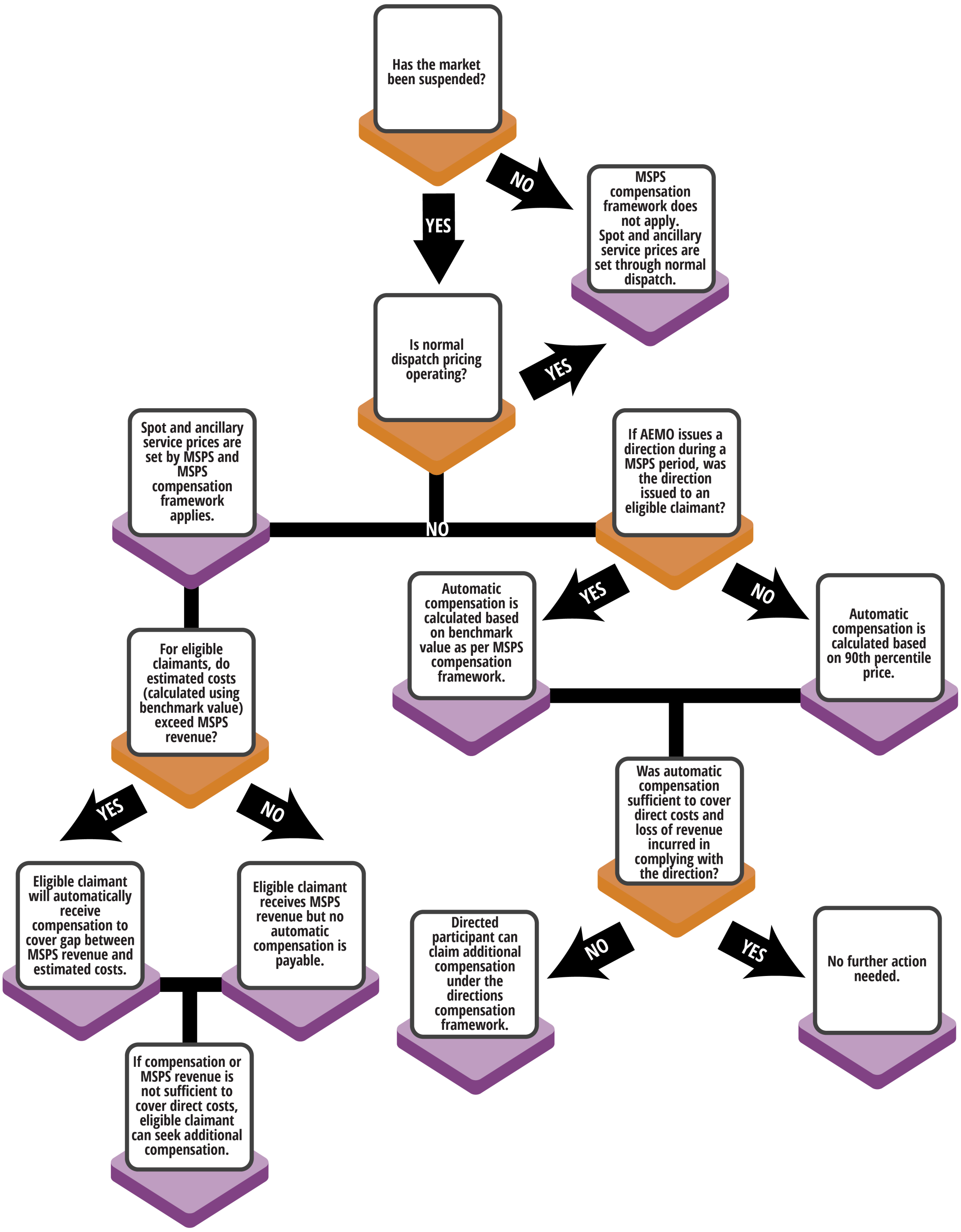
region. This is discussed further in section 4.5.1.) One submission in response to the draft determination noted the potential for generators in a neighbouring region (or regions) to bid unavailable and await direction in the event that prices are scaled as a result of the application of the MSPS, making the price in the neighbouring region/s too low to cover a generator's short run costs. The objective of AEMO's rule change request was to remove the current incentive for generators to withdraw in response to low prices and await direction. Consistent with this, and noting proposed changes to the way in which prices in the MSPS are to be determined (discussed in section 4.5.2), the final rule makes scheduled generators in neighbouring region/s eligible for compensation if they incur loss during those intervals that are impacted by scaling. During such intervals, if a generator's costs (estimated using benchmark values) exceed the revenue it earns based on the scaled price, compensation will automatically be payable to cover the gap. If automatically calculated compensation is not sufficient, a claim for additional compensation may be made.

- The final rule adjusts the cost recovery mechanism so that all costs are recovered through the directions framework (rather than through a mixture of the APP and directions framework cost recovery mechanisms). This will streamline the cost recovery process and is also more appropriate given the potential for compensation to be paid to generators in neighbouring regions who incur loss due to price scaling. (While the APP framework recovers costs solely from consumers in the region subject to the administered price cap, the directions framework recovers costs from consumers in accordance with the 'regional benefit test' - meaning the cost of compensation payments may be borne by consumers in more than one region.)
- The final rule confers discretion on AEMO to refer claims for additional compensation to an independent expert where such claims exceed $50,000 (making the provision discretionary rather than mandatory). This was in response to concern raised by two stakeholders regarding the additional cost that a claimant could be expected to incur (via the administrative fee) if a claim for additional compensation is referred to an independent expert. One stakeholder suggested that a claim could exceed the threshold but still be straight forward. Rather than increase the threshold or apply it to a shorter period (e.g. a single trading day), the final rule makes the provision discretionary rather than mandatory, giving AEMO the flexibility to deal with larger claims in house, rather than an obligation to refer all claims in excess of $50,000 to an independent expert.

A schematic of the MSPS compensation framework is overleaf and further detail on the final rule can be found in chapter 4.

Having regard to the issues raised in the rule change request and during consultation, the Commission is satisfied that the final rule will, or is likely to, contribute to the achievement of the NEO because it achieves AEMO's objective in requesting the rule change, minimises perverse incentives that could lead to inefficient bidding and dispatch outcomes, and achieves a fair balance between the interests of market participants and consumers.

Figure 3.1: Market suspension pricing schedule compensation framework



Source: AEMC. Note that 'MSPS revenue' encompasses revenue earned when prices are scaled due to the application of the MSPS.

4 ASSESSMENT OF THE FINAL RULE

This chapter summarises the key issues considered by the Commission in developing the final rule, including:

- how compensation should be calculated
- compensable costs
- eligibility for compensation
- preventing forum shopping
- how the final rule achieves the NEO

4.1 How should compensation be calculated?

A central issue in developing the final rule is how compensation should be calculated.

In its rule change request, AEMO proposed that the compensation framework applicable to APP be extended so as to include MSPS periods. Under the APP framework, there is no automatic calculation of compensation and thus no predictability. Instead, each claimant has to itemise and substantiate the costs it has incurred (direct and, if applicable, opportunity costs). The AEMC then reviews this material to determine whether compensation is payable.

As discussed in chapter 1, this framework has only been used once – by Synergen Power in 2009, a claim that related to direct costs only. That process was lengthy and costly, imposing significant administrative costs on the AEMC. While the AEMC did not recover its costs from Synergen, it is reasonable to expect that Synergen incurred significant costs in pursuing its claim.

The directions compensation framework is markedly different. Generators who are directed by AEMO to provide energy or ancillary services are automatically compensated for their output at the 90th percentile price (based on prices in the preceding 12 months). Directed participants need not make a claim to AEMO – the 90th percentile price payment is automatic. However, a directed participant can also make a claim for additional compensation if the 90th percentile price is not sufficient to cover its costs. There is no fee to lodge such a claim and AEMO cannot recover its costs from the claimant.

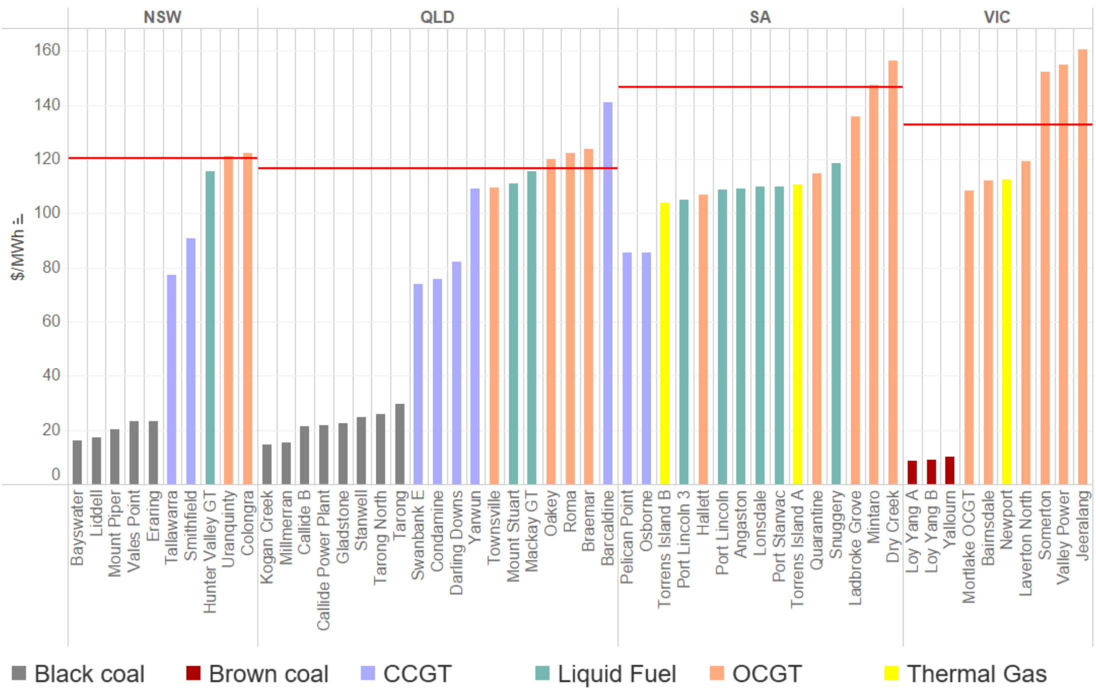
While timeframes apply to both processes, the directions compensation timeframe ‘clock’ runs from the date of the direction. Compensation based on the 90th percentile price is provisionally determined 23 business days after the end of the billing week in which the direction was issued by AEMO. If claims for additional compensation are made, time limits for finalising such claims range from 100 to 200 business days.

By contrast, the APP ‘clock’ runs from the date on which the AEMC confirms that it has sufficient information to assess the claim, thereby introducing an element of uncertainty as to timing. Once sufficient information is obtained and the claim process formally commences, the AEMC has 45 business days to determine direct cost only claims. Where claims also involve opportunity costs, the process includes public consultation and a final decision is to be made within around 90 business days of formal commencement. However, in both cases, the AEMC has discretion to extend these timeframes if reasonably necessary due to complexity or a material change in circumstances.

In considering what approach should be adopted to compensating participants who incur loss during MSPS periods, the Commission considered the incentives facing a generator during a market suspension event. For example, would a generator whose costs are higher than the MSPS price choose to generate and seek compensation via the APP process later, or would they prefer to await a direction from AEMO and avoid the cost and potential delay associated with making an APP-style compensation claim.

In addition to avoiding the administrative burden associated with the APP model, it is also the case that – for the majority of generators – the 90th percentile price is high relative to their direct costs (and potentially also their opportunity costs): see figure 4.1.

Figure 4.1: SRMC of scheduled generators and 90th percentile price (2017) by region



Source: AEMC analysis

Note: SRMC values are based on AEMO's 2018 Integrated System Plan modelling assumptions. The 90th percentile price applicable in each region is shown by the red line.

As such, generators may prefer to await a direction and receive the 90th percentile price rather than incur the cost and delay associated with seeking compensation under the APP model (which compensation would be calculated by reference to their costs, rather than by reference to the 90th percentile price).

4.1.1 Stakeholder views in response to the consultation paper

The probability that generators may prefer to await a direction rather than apply for APP style compensation is a point reflected in most of the submissions received in response to the consultation paper. Of the six submissions received, only two supported the APP model[78], with the remainder supporting a more bespoke or hybrid approach.[79] While AGL supported the APP model, it noted that 'there could be merit in embedding a base amount of compensation to provide predictability and certainty in the MSPS compensation process'.[80]

Recognising the potential for generators to prefer a direction over APP-style compensation, the consultation paper explored whether an alternative approach to that proposed by AEMO warranted consideration. For example, designing a MSPS compensation framework that combines elements of both the APP and directions compensation frameworks.

The Australian Energy Council supported a bespoke or hybrid approach, rather than the APP model. It noted that, to be effective, the compensation framework has to be 'financially favourable, easily accessible and predictable'.[81] Snowy Hydro also supported a hybrid approach that incorporates elements of both the APP and directions compensation frameworks. It noted that 'any inconsistency between compensation frameworks under market suspension compared to directions would incentivise participants to take the less onerous approach.'[82]

Two submissions in response to the consultation paper (from Snowy Hydro and EnergyAustralia) suggested that compensation be calculated based on the 90th percentile price, as per the directions compensation framework. However, the Commission is of the view that any MSPS compensation framework must be designed so as not to create a new problem (such as incentivising inefficient bidding and dispatch outcomes) while seeking to solve another (namely, removing the current incentive to await direction where prices in the MSPS are too low to cover a generator's costs).[83]

EnergyAustralia recognised this issue, stating: 'As identified by the AEMC, any compensation framework must be designed so as not to create new incentives leading to similarly perverse outcomes.' EnergyAustralia concluded by noting the importance of finding the 'right balance between additional costs to the consumer while providing certainty that generators have a mechanism to recover their costs'.[84]

78 See ERM Power and AGL submissions in response to the consultation paper, available at https://www.aemc.gov.au/rule-changes/participant-compensation-followingmarket-suspensi

79 See Australian Energy Council, Energy Australia, Snowy Hydro and Origin Energy submissions in response to the consultation paper, available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

80 AGL submission in response to the consultation paper, p. 3 available at https://www.aemc.gov.au/sites/default/files/2018-06/AGL-%20received%2022%20June%202018.pdf

81 See AEC submission in response to the consultation paper available at https://www.aemc.gov.au/sites/default/files/2018-06/Australian%20Energy%20Council_0.pdf

82 See Snowy Hydro submission in response to the consultation paper at https://www.aemc.gov.au/sites/default/files/2018-06/Snowy%20Hydro.pdf

83 This issue was discussed in section 5.2.1 of the consultation paper relating to this rule change request – available at https://www.aemc.gov.au/sites/default/files/2018-05/Consultation%20paper_3.pdf

84 EnergyAustralia submission in response to the consultation paper, pp. 3-4, available at https://www.aemc.gov.au/sites/default/files/2018-06/EnergyAustralia.pdf

In responding to the consultation paper, Snowy Hydro acknowledged that compensation based on the 90th percentile price may lead to over compensating claimants, but noted that it would also result in lower administrative costs than the APP model.[85]

4.1.2 Stakeholder views in response to the draft determination

Four submissions were received in response to the draft determination - from ERM Power, Origin Energy, AGL and EnergyAustralia. While all submissions supported the broad approach underpinning the draft determination, two submissions (ERM Power and EnergyAustralia) raised issues regarding the estimation of short run costs. AGL's submission suggested an alternative approach to cost recovery. The issues raised are discussed in turn below and in Appendix B.

4.2 Commission findings

4.2.1 Avoiding inefficient outcomes

The Commission notes that – while directions are issued to a select few participants – the new MSPS compensation framework will apply to all eligible parties who opt to provide services during a MSPS period and incur a loss. This is a significant distinction. The 'ex post' directions compensation framework would be available only to those generators to whom AEMO has issued directions (after first identifying which generators can supply the required services at least cost). By contrast, the new MSPS compensation framework will apply 'ex ante' to all eligible parties.

Following the SA market suspension in late 2016, AEMO concluded 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. 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 market floor price - 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.[86]

If – as proposed by some stakeholders – MSPS compensation were to be calculated based on the 90th percentile price (or some other financially favourable approach), this could have the unintended effect of encouraging higher cost generators to bid available at a low price (knowing this will have no impact on price outcomes since prices are set by the MSPS, and knowing that they will be compensated at the 90th percentile price or similar). This could in turn result in lower cost generators being displaced, leading to inefficient dispatch outcomes

85 See Snowy Hydro submission in response to the consultation paper, p. 2, available at https://www.aemc.gov.au/sites/default/files/2018-06/Snowy%20Hydro.pdf

86 AEMO, *Market Suspension Change Proposals – Discussion Paper for distribution to NEM Market Suspension Technical Working Group*, April 2017, pp. 5-6.

and higher than necessary compensation payments (which are funded by market customers[87] and therefore by consumers).

4.2.2 Estimating short run marginal costs

To address this risk of incentivising inefficient bidding and dispatch outcomes, the final rule creates a framework that compensates generators by reference to their estimated short run marginal costs (SRMC), rather than based on the 90th percentile price or the APP model. Under the new framework, AEMO will calculate a capacity-weighted average SRMC for each scheduled generator type in each region using data collated for use in the National Transmission Network Development Plan (NTNDP) or Integrated System Plan (ISP).

The inaugural ISP was released in July 2018, consistent with recommendations made by the Independent Review into the Future Security of the NEM (the Finkel Review). As the ISP's purpose and scope encompass those which would normally be covered in AEMO's NTNDP, the Australian Energy Regulator (AER) has permitted AEMO to defer the release of the 2017 NTNDP and integrate it into the ISP.[88]

Like the NTNDP, it is expected that the ISP (and the underlying SRMC and other data used to produce it) will be updated regularly – meaning that the SRMC data will, to a reasonable extent, be able to keep pace with changes in (for example) fuel prices. Clause 5.20.1 of the NER requires AEMO to consult with market participants on the data it proposes to use in developing the NTNDP/ISP, thus providing a process by which stakeholders can provide feeedback if they disagree with the data AEMO proposes to use.

The estimation of SRMC will use the well accepted formula set out below.[89] (In the equation, VOM stands for variable operating cost.)

$$SRMC\left(\frac{\$}{MWh}\right) = Fuel\ cost\left(\frac{\$}{GJ}\right) \times efficiency\left(\frac{GJ}{MWh}\right) + VOM\left(\frac{\$}{MWh}\right)$$

Using the ISP data, SRMC will be estimated for each scheduled generator in the relevant category in a given region.

Categories will be established by AEMO in a 'Market Suspension Compensation Methodology' and would likely include black and brown coal, open and combined cycle gas turbines, hydro and large scale batteries. While there are currently no scheduled biomass, solar thermal or other renewable generators (leaving aside hydro which is addressed below), such categories could be included in anticipation of new market entrants of this kind.

A capacity-weighted average of these SRMC values will then be calculated for each category of scheduled generator in each region. This estimate, supplemented by a 15 per cent

87 NER, clause 3.15.8(b)

88 See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

89 EY, *Reliability Standard and Settings Review 2018 – Modelling Report*, 13 April 2018, p. 15

premium to account for divergences between estimated and actual costs, will be the 'benchmark value' used to calculate compensation for generators of that type in that region.

This approach will mean generators can be compensated fairly while minimising perverse incentives that could lead to inefficient bidding behaviour and dispatch outcomes, and without imposing unwarranted costs on consumers – who ultimately bear the cost of compensation payments. The quantum of compensation automatically payable should mean that generators do not have an incentive to bid available at a low or negative price with a view to being dispatched and then being more than adequately compensated at – for example – the 90th percentile price.

At the NEM Wholesale Consultative Forum on 26 June 2018, AEMO announced that it would shortly commence using the NTNDP/ISP SRMC data in the calculation of direct costs incurred or avoided by affected participants as a result of a direction being issued or the Reliability and Emergency Reserve Trader (RERT) being activated.[90] This followed consultation with industry stakeholders who indicated support for the approach. The use of the same SRMC data in the final rule is consistent with this approach.

Over time, it may be appropriate to include in the compensation framework other classes of market participant – such as ancillary service loads and demand response providers (discussed below in section 4.5) . However this would require such parties to have similar characteristics to those mentioned above – namely, that they can in practice be directed by AEMO to provide services, and that there is a reasonable and transparent means to estimate their direct short run costs without imposing a significant administrative burden.

It is likely that further changes to the NER and the market suspension compensation methodology will be necessary if new classes of participants are to become eligible for compensation under the MSPS compensation framework. However no change to the NER will be required if a new class of generating unit were to be included among those classifed by AEMO as a scheduled generating unit in accordance with Chapter 2 of the NER.

4.2.3 Generator start costs

In response to the draft determination, ERM and EnergyAustralia submitted that generator start costs should be included in the automatic calculation of compensation to remove the risk that thermal plants will not recover their start-up costs when prices in the MSPS are not sufficiently high (or not high enough for long enough).[91] Both stakeholders note that AEMO proposes to change the manner in which prices in the MSPS are determined.[92] One important change AEMO is proposing is to impose upper and lower bounds on the prices in the MSPS,

90 Under clause 3.12.2, an affected participant is entitled to receive from, or must pay to, AEMO an amount that will put the participant in the position it would have been in had AEMO not issued a direction or activated the RERT. This amount is to be calculated taking into account, as appropriate, the matters set out in clause 3.12.2(j). These include the direct costs incurred or avoided by the affected participant as a result of the direction or RERT activation (including fuel costs, incremental maintenance costs, incremental staffing costs).

91 Submissions from ERM (see p. 3) and EnergyAustralia (see p. 2) are available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

92 See AEMO, *Market Suspension Pricing Schedule – Draft Report and Determination*, September 2018 available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2018/Market-Suspension-Pricing/Market-Suspension-Pricing-Schedule-Draft-Report-and-Determination.pdf

consistent with the $300 price cap and -$300 floor imposed during administered price periods. Both ERM and EnergyAustralia are concerned that the proposed cap on MSPS prices will reduce the ability of peaking plants in particular to recover their start costs.[93]

Similarly, AGL notes that 'broad-brush calculations of short run marginal costs (SRMC) are problematic, as each participant's fuel costs will be widely different, and dependent on factors such as start-up costs, spot commodity prices or haulage limits'. However, AGL continues: 'despite our concerns with SRMC benchmark calculations, we appreciate that should the benchmark underrepresent actual direct costs, a participant can make a claim for additional compensation to recover the difference between that amount and the automatic compensation amount'.[94]

The Commission does not support the inclusion of generator start costs in the automatically calculated component of compensation. The underpinning rationale of the final rule is to provide a compensation framework that is simple and predictable (similar to the directions compensation framework) and able to provide compensation that is adequate for the majority of scheduled generators. The choice of the NTNDP inputs as the basis for calculating automatic compensation was designed to avoid 'special pleading' by generators regarding the costs they bear – a process more suited to the bespoke (and administratively costly) compensation framework used for APP.

The automatically calculated compensation is not designed to be precisely reflective of actual costs. Rather, it is considered a reasonable approximation that avoids the significant administrative costs associated with achieving higher accuracy. The ability to claim additional compensation is the safety net available where the automatically calculated compensation is insufficient to cover a particular participant's costs (a point recognised by AGL, which did not seek to have start costs included in the automatically calculated compensation).

Including start costs in the automatically calculated compensation could significantly complicate the development and administration of the scheme for AEMO (given the plant specific nature of start costs) and would likely increase the compensation costs passed through to consumers. The estimation of start costs is not a straight forward matter. For example, start costs were included in a claim for additional compensation following directions issued by AEMO to Mt Stuart power station in March 2017. The independent expert report relating to that claim (the Harding Katz report) discussed the four methods used by Origin Energy to estimate start costs. The four methods are shown in the table below and, as can be seen, the variation between the approaches is significant.[95]

93 This change to the MSPS methodology was supported by EnergyAustralia on the basis that it would preserve short to medium term pricing signals while limiting extreme price outcomes: see p. 2 of EnergyAustralia submission to AEMO available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2018/Market-Suspension-Pricing/Market-Suspension-Pricing-Schedule—-AEMO-Consultation—-EnergyAustralia-Submission.pdf

ERM Power did not support the imposition of a $300 cap as prices above this level 'form part of the normal price signals for the efficient dispatch of generation and demand management and therefore should be included in the calculation': see p. 4 of the ERM submission available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2018/Market-Suspension-Pricing/20180806-AEMO-Consultation—-Market-Suspension-Pricing-Schedule-Consultation-Final.pdf

94 See p. 1 of AGL's submission in response to the draft determination.

95 Harding Katz Pty Ltd, *Compensation for Directions in Queensland on 28 and 29 March 2017 – Independent Expert Final Report*, 4 September 2017, p. 10.

Figure 4.2: Estimation of Mt Stuart start costs using four different methods

Estimating Method	Mt Stuart Unit 2		Mt Stuart Unit 3	
	Low	High	Low	High
LRMC	$10,210	$35,268	$12,050	$17,178
Average cost method	$9,562	$38,767	$11,850	$21,790
Discounted average cost method	$8,497	$26,439	$6,048	$12,837
Single cycle method	$29,232		$9,986	

Source: Harding Katz report citing Origin Energy estimates

While Origin Energy proposed that compensation for start costs be based on the LRMC method (assuming a ten year period), the independent expert opted instead to apply the single cycle method which resulted in a lower compensation payment than had been sought by Origin.

The discussion in the Harding Katz report suggests that including start costs in the automatically calculated compensation component could entail significant additional work for AEMO. This is very hard to justify given the rarity of market suspension events and the ability for generators to make a claim for additional compensation should the need arise. Even if it were a simple matter to determine start costs for each plant, including such costs could have perverse effects on bidding behaviour, as discussed below.

Including start costs in the automatically calculated compensation component would mean that generators with relatively flexible plant are financially indifferent as to whether they can recover start costs from spot prices. This is in stark contrast to the discipline that would apply during normal market operation. As EnergyAustralia notes in its submission in response to the draft determination (p. 2): 'under normal market operation, participants take this cost into account when making unit commitment and de-commitment decisions'. When the MSPS applies, prices are set and known in advance (and are immune to generator bidding behaviour). Given this, generators may have comparatively greater certainty during MSPS periods as to whether, if dispatched, they will be able to recover their start costs.

Including start costs in automatic compensation could incentivise open cycle plant (in particular) to bid at low or negative prices in order to ensure they are dispatched. This could have the effect of displacing generators which would normally sit lower in the merit order, leading to disorderly bidding and inefficient dispatch outcomes while at the same time increasing compensation costs to consumers. This would not be consistent with the NEO or the criteria used to assess this rule change proposal (in particular, whether the rule will incentivise market participants to help restore or maintain a reliable and secure electricity supply during market suspension while not encouraging inefficient bidding and dispatch outcomes).

Indifference to start costs may also mean that a generator whose actual short run costs are higher than the applicable generation benchmark value is more likely to de-commit in response to lower MSPS prices and then restart once MSPS prices rise. (This is an issue already creating challenges for AEMO in operating the market in SA: i.e. generators de-commit when the spot price falls and await direction[96], then advise AEMO to cancel the direction when it becomes more profitable to participate in the market voluntarily.) Given this, automatic inclusion of start costs may not optimally support maintenance of supply at a time of already heightened control room stress.

Finally, EnergyAustralia's concern – that capping prices in the MSPS 'may mean that OCGT units (for example) are less likely to voluntarily participate [as distinct from being compelled by direction to participate] in the market under suspension due to the residual uncertainty that start costs may not be able to be recovered' – is not well founded given that the incentive to withdraw and await direction has been removed by the final rule. This is achieved by providing that, when a direction is issued to an eligible claimant during a MSPS period, compensation for that directed participant is to be calculated on the basis of benchmark values, rather than based on the 90th percentile price. (The inclusion of this provision was expressly supported by both ERM and AGL.) Again, where automatically calculated compensation is insufficient to cover a directed participant's costs, that participant may make a claim for additional compensation.

For these reasons, the final rule does not incorporate start costs in the calculation of automatic compensation.

4.2.4 Premium to be included in benchmark value

The draft determination included a 10 per cent premium (additional to the capacity-weighted average estimated SRMC per MWh) in order to accommodate – to a reasonable extent – differences between estimated and actual costs facing a given generator at a given time. The Commission considered that setting the premium at this level would allow generators to be compensated adequately even if – for example – fuel costs are higher than those estimated for planning purposes (noting that such inputs are updated annually, in consultation with market participants, in accordance with clause 5.20.1 of the NER).

Applying a ten per cent premium, a hypothetical generator with an estimated SRMC of $85/MWh would be compensated at the rate of $93.50/MWh. If such a generator were still out of pocket, it could lodge a claim for additional costs (and could make a submission to AEMO regarding cost assumptions when consultation on the NTNDP inputs next occurs).

96 AER noted in the January - March 2018 *Quarterly Compliance Report* that 'we are currently considering the conduct of some Scheduled Generators who have advised AEMO of their intention to desynchronise at shorter notice than is required by clause 4.9.7(a) of the Electricity Rules. Further, we are examining whether this has led to AEMO issuing directions to generators to remain synchronised, to ensure the market remains in a secure operating state': see p. 7 of the report at https://www.aer.gov.au/system/files/Quarterly%20Compliance%20Report%20January%20-%20March%202018%20.pdf

The draft determination noted that the relationship between fuel cost and SRMC is linear. Thus, a 10 per cent increase in fuel cost would increase SRMC by around 10 per cent. In the draft determination, the Commission considered that increasing the premium significantly above 10 per cent risked creating inefficiencies relating to both bidding behaviour/dispatch outcomes and compensation costs borne by consumers. On this basis, a higher premium was not supported.

4.2.5 Stakeholder views in response to draft determination

In their submissions in response to the draft determination, EnergyAustralia and ERM both raise concerns regarding the NTNDP input assumptions underpinning the benchmark values – particularly in relation to the heat rate (or thermal efficiency).[97] Both note that the heat rate in the NTNDP data is premised on the plant operating at 100 per cent capacity and ERM further notes that the data is based on winter operating conditions. AEMO notes that the heat rates used in the ISP reflect static values that are considered appropriate for normal loading but do not purport to reflect fuel use in all conditions.

ERM notes that 'actual heat rates could vary by 30% based on time of year and actual generator loading compared to the values contained in the NTNDP/ISP'.[98] To address this variability in heat rates, ERM proposes that the 10 per cent premium included in the draft rule be increased to 25 per cent.[99]

The Commission recognises that heat rates can vary significantly in response to plant loading. Indeed, as noted in the 2016 Australian Power Generation Technology Report, the performance of a gas turbine is affected by a number of factors including - in addition to plant loading - ambient temperature, relative humidity, fuel type, inlet pressure drop, outlet pressure drop and site elevation.[100]

That report provides an example heat rate curve showing the open cycle part-load performance curve under two conditions. As can be seen in figure 4.3, in the first scenario, the partial loading is achieved by reducing fuel input without closing the inlet guide vanes. In the second, the inlet guide vanes are closed and then the fuel input is reduced. In both cases, the heat rate deteriorates as loading reduces. The report notes that part-load operation may be achieved most efficiently by closing the inlet guide vanes at the compressor inlet.[101] This demonstrates that heat rates vary not only in response to plant loading and factors such as ambient temperature but also the manner in which the plant is operated.

97 See p. 2 of the EnergyAustralia submission and p. 2 of the ERM submission, available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

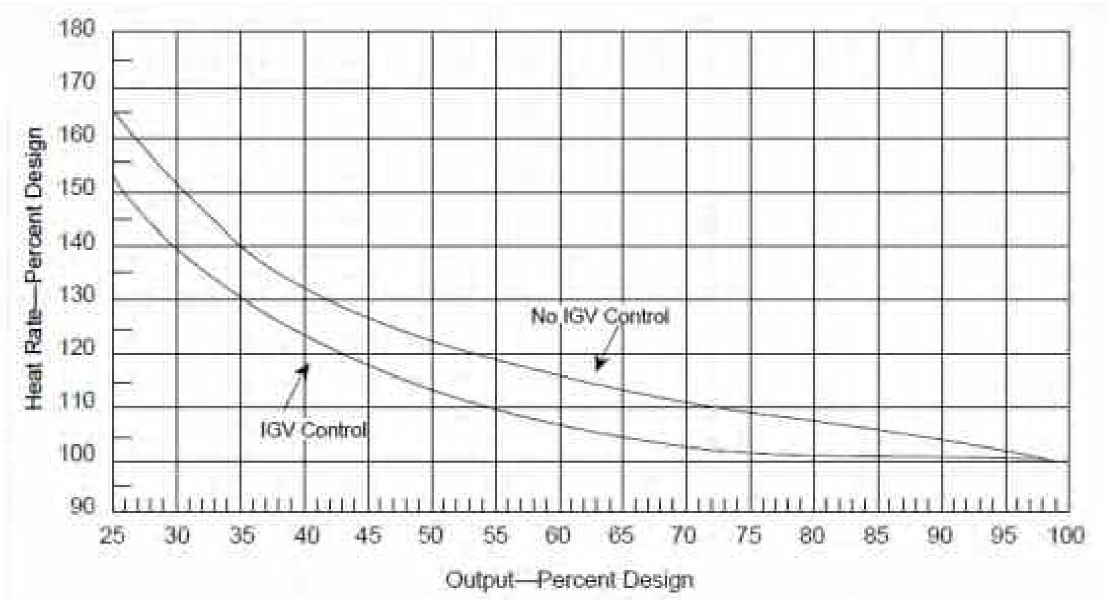
98 See p. 2 of the ERM submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

99 ibid

100 C02CRC, *Australian Power Generation Technology Report 2016*, p. 84.

101 ibid, pp 89-90

Figure 4.3: Open cycle part-load performance curve



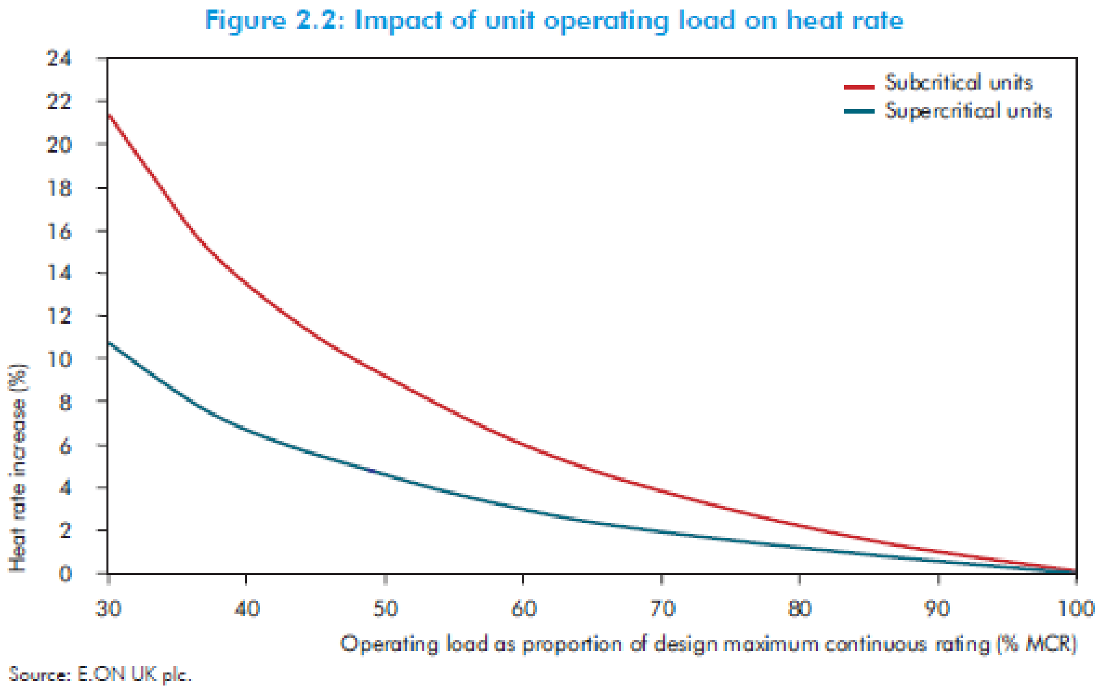
Source: 2016 Australian Power Generation Technology Report
Note: IGV = inlet guide vane

Similarly, an IEA report notes that the 'efficiency [of coal plants] is significantly affected when plants operate under off-design conditions, particularly part-load operation'. The figure below illustrates the effect of running at lower loads on the performance of subcritical and supercritical coal units.[102] As can be seen, operating a subscritical unit at 30 per cent capacity entails a heat rate that is just over 20 per cent higher than when the plant is operating at maximum continuous rating. This translates to higher fuel costs and thus SRMC when the plant is operating at less than full capacity.[103]

102 International Energy Agency, *Power generation from coal - measuring and reporting efficiency performance and CO2 emissions*¸ 2010, p. 20.

103 See also PDMV Prasad, *Heat Rate – the pulse rate of power plant*, available at https://www.slideshare.net/porhalakrao/heat-rate-of-coal-fired-power-plant This report also confirms that heat rates rise as plant loading decreases below maximum continuous operation – meaning more units of heat input are required to deliver a unit of energy output when the plant is partially loaded.

Figure 4.4: Impact of unit operating load on heat rate



Source: IEA

Ambient temperature, humidity and altitude also have an important impact on the efficiency of thermal plant. This is because hot and humid air is less dense than dry, cooler air. In gas turbines, power output is dependent on the mass flow through the compressor. As the density of air decreases in warmer weather, more power is required to compress the same mass of air. This reduces the efficiency and thus output of gas turbines. Studies have found that gas turbine efficiency deteriorates by one per cent for every 10 degree (centigrade) rise in temperature above standard reference conditions.[104] This translates into a power output reduction of five to 10 per cent, depending on the type of gas turbine.[105]

Ambient temperature and humidity are exogenous factors which are impossible to predict and accurately accommodate via a single, static premium in an 'ex ante' compensation framework. This is particularly true when the framework applies across a wide and variable region such as the NEM, encompassing a wide range of plant types, generation mixes and operating conditions.

The Commission considers that increasing the premium to 25 per cent (as suggested by ERM Power) does not strike an optimal balance between the interests of generators and

104 Farouk et al, "Effect of Ambient Temperature on the Performance of Gas Turbines Power Plant", 2013, available at http://www.ijcsi.org/papers/IJCSI-10-1-3-439-442.pdf

105 Wartsila, Combustion Engine vs Gas Turbine: Derating due to Ambient Temperature, available at https://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-derating-due-to-ambient-temperature

consumers, noting that generators have the option to make a claim for additional costs if automatic compensation is insufficient while consumers do not have the option to seek a refund in the event that automatically calculated compensation proves too generous. Assuming that a plant will always run at its minimum safe operating level is considered unduly conservative, and is inconsistent with the ERM submission which notes that 'during a market suspension, generating units could be required to operate anywhere between minimum stable loading and maximum capability'.[106] In addition, such an assumption would have significant implications for costs to consumers. Accordingly, the Commission has decided to increase the premium to 15 per cent. This is discussed further below in section 4.2.7.

4.2.6 Fuel costs

An increase in the premium would also help accommodate differences between estimated and actual fuel costs, an issue raised by EnergyAustralia and ERM (and AGL in passing).[107] EnergyAustralia's submission urges the Commission, in finalising the determination, to consider the static nature of the NTNDP inputs (which may not reflect prevailing market conditions) so that participants 'are not reliant on claiming additional compensation to cover costs'.[108]

ERM suggests in its submission that 'fuel input costs should be based on the real time costs of fuel as set by verifiable transparent benchmarks such as the Gas Short Term Trading Markets'.[109] ERM suggests that the applicable benchmarks for fuel costs would be consulted on by AEMO during the development of the Market Suspension Compensation Methodology. This would require a change to the rule given that the NTNDP inputs are referenced in the rule and that, as noted in section 3.4, consultation regarding the AEMO methodology is to focus on matters other than the NTNDP inputs.

The Commission does not support ERM's proposal to link fuel costs to other benchmarks as this may not reflect a generator's contracted position with respect to fuel costs. Doing so would further complicate a framework designed around a pre-existing data set which – while not purporting to be cost-reflective – has the benefit of being 'arm's length' and not subject to special pleading regarding individual generator inputs (other than via the NTNDP input consultation process that is required to take place each year). The Commission also notes that, as discussed in section 4.2.2, industry has already accepted the use of this data set for the purpose of calculating avoided costs in accordance with clause 3.12.2.[110] To the extent that participants have concerns with the data, they have the opportunity to raise those during the annual consultation on the NTNDP inputs.

106 See p. 2 of ERM submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

107 See p. 2 of the ERM submission, p. 2 of the EnergyAustralia submission and p. 1 of the AGL submission, all available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

108 See p. 2 of EnergyAustralia submission

109 See p. 2 of ERM submission

110 Under clause 3.12.2, an affected participant is entitled to receive from, or must pay to, AEMO an amount that will put the participant in the position it would have been in had AEMO not issued a direction or activated the RERT. This amount is to be calculated taking into account, as appropriate, the matters set out in clause 3.12.2(j). These include the direct costs incurred or avoided by the affected participant as a result of the direction or RERT activation (including fuel costs, incremental maintenance costs, incremental staffing costs). Since 1 July 2018, AEMO has been using the NTNDP data for the purpose of calculating these incurred or avoided costs.

The Commission also notes the importance of striking an efficient balance between accuracy and administrative cost. A more accurate framework will be more costly to develop and administer – an important consideration given the rarity of market suspension events. There is also a trade-off between transparency and accuracy (since the most accurate data will be commercial in confidence and not suitable for inclusion in publicly available benchmark value calculations).

In its submission to the consultation paper, ERM expressed support for the APP compensation model proposed by AEMO (i.e. based on bespoke compensation claims). It noted: 'The Commission, in considering possible alternatives, has raised concern that the proposed process [based on the APP model] may be unnecessarily complex and could result in an unnecessary administrative burden. ERM Power does not share these concerns and does not support these proposed alternatives… We believe the level of compensation which should be available to participants during periods of market suspension where the Market Suspension Pricing Schedule is in effect is dependent on the specific participant, event and timing. As such, we do not believe it is possible to create a specific formula which could apply under all circumstances.'[111]

By contrast, ERM's more recent submission 'supports the aim of the draft determination to automate the compensation process as much as possible to reduce additional administrative costs to participants, the Market Operator and the market as a whole compared to the alternative where the assessment of compensation… would occur on a bespoke basis'.[112] However, ERM has concerns with aspects of the draft rule and considers that these will result in the participant and AEMO incurring additional costs to lodge and process claims for additional compensation. (Based on the approach supported in its earlier submission, all participants who incur loss during a MSPS period would need to make a bespoke claim in order to receive any compensation.)

The Commission recognises that there has been significant recent volatility in fuel prices (e.g. the Newcastle spot coal price has risen 45 per cent in the past 12 months[113]). However, it would not be efficient to set the premium so high as to cover all such contingencies: doing so would impose significant additional costs on consumers and such costs may not be warranted at the time the market is suspended. A more efficient approach would be for generators who incur loss to make a claim for additional compensation. Nonetheless, there is a case to increase the premium to help accommodate factors which are intrinsic to the nature of generating plant (such as variable heat rates, discussed above) and exogenous factors such as moderate variations in fuel costs.

4.2.7 Revised premium in final rule

As noted earlier, ERM proposes that the 10 per cent premium included in the draft rule be increased to 25 per cent. While setting the premium at this level is considered to tip the scale

111 See p. 2 of ERM Power submission in response to the consultation paper available at https://www.aemc.gov.au/sites/default/files/2018-06/ERM%20Power_0.pdf

112 See p. 2 of the ERM submission in response to the draft determination, available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

113 AEMC analysis of Bloomberg data

too far in favour of generators (at the expense of consumers), a question arises as to whether the premium should increase and, if so, by how much. While EnergyAustralia did not request a particular premium, it did urge the Commission to consider variable heat rates and fuel costs in finalising the Rule so that participants are not reliant on claiming additional compensation to cover costs.[114] Neither AGL nor Origin requested an increase in the premium.

A factor to consider in determining the premium to include in the compensation formula is that this single percentage figure will apply to a range of generator types (e.g. coal, OCGT, CCGT, hydro and batteries) operating in regions within the NEM that differ considerably. For example, scheduled generators in NSW are predominantly coal fired while scheduled generators in South Australia are predominantly gas fired. Coal fired plants are less flexible than OCGT and CCGT plant and thus it is reasonable to assume that the heat rate of coal generators will vary less due to changes in plant loading compared with gas plants.

The variation in heat rate will also depend on the generation mix in each region. For example, the high penetration of wind and solar in South Australia means that output from scheduled generators may vary in line with load and the degree of energy output from low cost renewable generators. This factor is not as pronounced in other regions as yet.

Having regard for such factors, it is important not to adopt a premium designed to accommodate the heat rate variability of certain plant (particularly OCGT) and apply it to all generator types. Using a single figure inherently risks over-compensating some generators and under-compensating others. In order to protect consumer interests, it is important that the premium not be set too high. The more efficient approach, as noted previously, is for affected generators to seek additional compensation.

In light of these considerations, the Commission considers that a 15 per cent premium will strike an appropriate balance between the interests of generators and consumers. Adopting a 20 per cent premium would result in compensation payments to generators approaching the quantum of compensation payable under the directions framework. Building on the analysis included in the draft determination, the cost of compensating SA scheduled generators using various approaches is set out below. This analysis compares the costs incurred by scheduled generators during the 2016 market suspension event (based on AEMO's SRMC data) with the revenue earned under the MSPS, and estimates the compensation payable using various approaches (the 90th percentile price and SRMC plus varying premia).

The aggregate outcomes, in terms of total payments to scheduled generators over the course of the entire market suspension, are as follows:

- actual MSPS prices: total payments of $9.64 million
- compensation based on 90th percentile of prices: total payments of $17.38 million
- SRMC based compensation:
  - SRMC only: $14.1 million

114 See p. 2 of the EnergyAustralia submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

- SRMC + 10%: $15.51 million
- SRMC + 15%: $16.22 million
- SRMC + 20%: $16.92 million
- SRMC + 25%: $17.63 million

As can be seen, adopting a 20 per cent premium would result in compensation payments approaching the compensation payable if all generators were directed and paid at the 90th percentile price. Adopting a 25 per cent premium, as suggested by ERM Power, would result in compensation payments exceeding the quantum payable at the 90th percentile price. This would be a highly undesirable outcome as it would result in a compensation framework that – at least in South Australia – is more costly for consumers than the existing arrangements (reliance on directions when a generator withdraws capacity due to low MSPS prices).

Given this, a 15 per cent premium has been included in the final rule. This will help accommodate variations in heat rates and fuel costs thereby reducing reliance on additional compensation claims with their attendant administrative costs. At the same time, this approach will mitigate cost impacts on consumers, consistent with the NEO.

4.2.8 Proposed approach to hydro and batteries

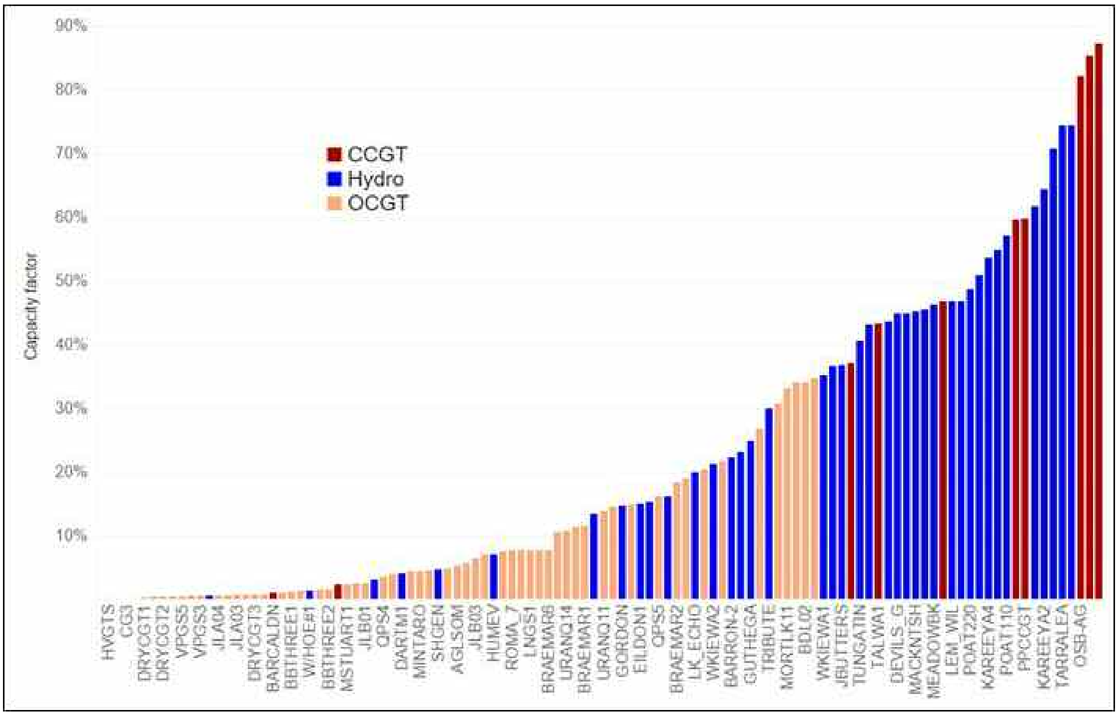
As noted earlier, the final rule requires AEMO to develop a Market Suspension Compensation Methodology that will set out the detail of how benchmark values will be calculated. While development of the methodology is a matter for AEMO, the Commission notes that some categories of scheduled generation may be under-compensated if compensation is calculated strictly on the basis of unadjusted NTNDP/ISP inputs.

For example, using the NTNDP/ISP inputs for hydro would give a low SRMC estimate that does not reflect the value of water held in storage and thus is not an appropriate value to be used for the purpose of calculating compensation. Similarly, there are gaps in the currently available NTNDP inputs relating to large scale batteries.

To address these issues, the Commission suggests that benchmark values for hydro and large scale batteries be set by reference to the values applicable to gas plants in the same region.

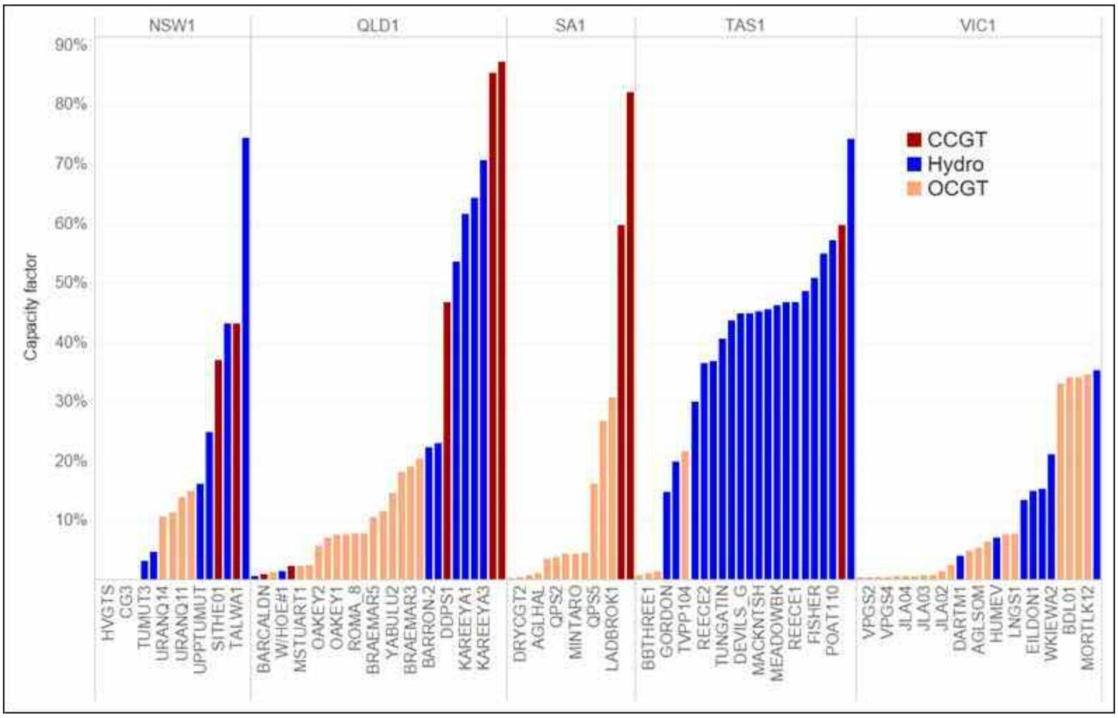
AEMC analysis shows that hydro capacity factors can vary widely, as can be seen in figure 4.5. For hydro plants with a capacity factor greater than 40 per cent in the previous 12 months, it appears appropriate that the benchmark value of CCGTs in the same region would apply. For hydro plants with a capacity factor less than or equal to 40 per cent, it appears appropriate that the benchmark value of OCGTs in the same region would apply. Figure 4.6 sets out the relevant capacity factors by region.

Figure 4.5: Ordering of OCGT, CCGT and hydro units by 2017 capacity factor (NEM wide)



Source: AEMC analysis

Figure 4.6: OCGT, CCGT and hydro 2017 capacity factors by region



Source: AEMC analysis

Under the final rule, AEMO will determine a capacity-weighted average SRMC for plants in the same category (OCGT or CCGT) in the same region and add the 15 per cent premium. Subject to the development of the Market Suspension Compensation Methodology, one option could be for AEMO to use this benchmark value to calculate the compensation automatically payable to scheduled hydro plants in the same region (using either OCGT or CCGT values, depending on the capacity factor of the relevant hydro plant in the previous 12 months).

The draft determination noted that, until such time as better data is available, the approach of setting benchmark value by reference to OCGT benchmark value may also be appropriate in relation to scheduled batteries.

While these issues can be further refined in the development of the AEMO methodology, the approach outlined above provides a possible means to automatically calculate compensation without incurring the cost of assessing individual claims using a bespoke model such as the APP compensation framework. It is outlined here in order to identify possible approaches to compensate participants for whom the 'benchmark value' method may not, on a narrow application, produce an adequate level of compensation.

In its submission in response to the draft determination, AGL expressed concern regarding the above approach to hydro and batteries noting that 'for hydro, costs depend on inflows and outflows, and vary significantly throughout the year. For batteries, it is unclear how gas provides a representative benchmark and further, it is difficult to see the value that would be attributable to batteries during a market suspension event.'[115]

The Commission notes these concerns but considers that they are matters to be addressed in the course of developing the Market Suspension Compensation Methodology.

4.2.9 Proposed approach to ancillary service providers

On average, prices paid for electricity are significantly higher than those paid for the eight market ancillary services. For example, the 90th percentile price for electricity in all regions of the NEM for 2017 was in the range $115-145/MWh.[116] By contrast, the 90th percentile price in the most costly ancillary service market was less than $50/MWh in 2017.[117]

Most ancillary service market prices are very low, with 90th percentile prices ranging from around $0.10 - $5/MWh for much of the time. However, higher prices (up to around $45 per MWh) can occur in response to events such as Basslink outages. Increasing diversification in the FCAS market (e.g. the entry into the market of large scale batteries, demand response FCAS providers like EnerNOC and renewable energy FCAS providers such as Hornsdale Wind Farm 2) has put downward pressure on ancillary service prices.

Given this, it would not be efficient - and could create distortionary effects - to compensate ancillary service providers using the same approach as for energy generation. Accordingly, the final rule compensates ancillary service providers in a manner that is linked to the calculation of compensation for scheduled generators but takes into account the different costs involved in the provision of market ancillary services.

As noted earlier and set out in clause 3.14.5A of the final rule, the approach to calculating compensation for scheduled generators is to take the capacity-weighted average SRMC for a given generator type in a given region (the 'benchmark cost') and apply a 15 per cent premium. Thus, the 'benchmark value' for scheduled generators is expressed as average benchmark cost multiplied by 1.15. (For a generator with a benchmark cost of $85/MWh, the benchmark value is $97.75/MWh: i.e. 85 x 1.15.)

For ancillary services (raise and lower), the benchmark value will equate to the average benchmark cost multiplied by 0.15.[118] Thus, if the same generator as in the example above is enabled to provide ancillary services, the ancillary services benchmark value for compensation purposes will be $12.75/MWh: i.e. 85 x 0.15.

This reflects that the premium added to the SRMC estimate is in effect the opportunity cost for that generator of providing ancillary services rather than generating energy.

115 See p. 1 of AGL submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

116 See figure 5.1 on p. 24 of the AEMC Consultation Paper for this rule change, available at https://www.aemc.gov.au/sites/default/files/2018-05/Consultation%20paper_3.pdf

117 AEMC, *Consultation Paper, National Electricity Amendment (Participant compensation following market suspension) Rule 2018*, p. 23

118 As discussed in section 4.2.8, the fomula used to calculate the benchmark value for ancillary services appears to adopt a different approach to the premium but in fact the result is the same. The apparent difference is due to the different manner in which ancillary services are priced: being $ per MW per hour, rather than $/MWh which is the metric used for electricity prices.

Using the same example to illustrate: if the generator keeps capacity in reserve in order to be able to provide raise ancillary services by increasing output when called upon, it cannot be compensated at the rate of $93.50/MWh for energy generated by that capacity while the capacity is being held in reserve. On the other hand, the generator will not incur (estimated) costs of $85/MWh to generate energy using the capacity being held in reserve. The difference is the opportunity cost created by the premium: i.e. $12.75/MWh.

The same applies when a generator reduces its energy output when called upon to provide lower ancillary services. (In order to be able to provide such services, the generator will have to operate above its safe operating level.) When the generator's output decreases, its revenue for generation sent out will also decrease. On the other hand, as with the raise ancillary service example above, the generator will not incur (estimated) costs of $85/MWh to generate energy given the reduction in output. Again, the difference is the opportunity cost created by the premium, being $12.75/MWh.

This assumes that the SRMC estimate is a reasonable approximation of actual costs incurred. To the extent that the actual costs facing a given generator exceed the benchmark cost for that generator, the 'opportunity cost' will be less than the 15 per cent premium. Conversely, if the actual costs facing a given generator are lower than the benchmark cost for that generator, the opportunity cost will be greater than the premium.

The Commission recognises that the approach adopted in the final rule is an approximation that does not reflect the more complex reality that the opportunity cost of providing ancillary services is normally a function of the spot price, rather than the short run costs of a given generator. Nonetheless, it is considered a reasonable approach which avoids more complex or costly methods (such as assessing individual claims on their merits using the APP model).

The Commission also recognises that paying compensation on this basis may be considered generous in some instances, given the typically low price of market ancillary services. On the other hand, the continued provision of adequate ancillary services may be particularly important during a market suspension (e.g. where it has been triggered by a black system event). Given this, the proposed approach is considered reasonable.

AGL was the only stakeholder to comment on the approach to ancillary service providers outlined in the draft determination. While AGL queried whether the provisions would be used, it supported the approach to calculating compensation for ancillary service providers.[119]

4.2.10 How is the premium incorporated into the final rule?

The 15 per cent premium is incorporated into the final rule in clause 3.14.5A(e) and (f). In clause 3.14.5A(e), the benchmark value for generation (BVG) is defined as average benchmark costs multiplied by 1.15. In clause 3.14.5A(f), the benchmark value for ancillary services (BVAS) is defined as average benchmark costs multiplied by (0.15 divided by the number of trading intervals in an hour). While the two paragraphs appear to adopt a different approach in relation to the premium, they are in fact consistent.

119 See pp 1-2 pf AGL submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

The reason for the apparent difference relates to the manner in which estimated costs are calculated in clause 3.14.5A(d). In that clause, the costs deemed to have been incurred in connection with the provision of ancillary services are expressed as MWE x BVAS. In that formula, MWE is the sum of the relevant market ancillary services (in MW) which the eligible claimant's ancillary service generating unit has been enabled to provide during the MSPS period. BVAS is the benchmark value for ancillary services set out in clause 3.14.5A(f), as noted above.

If the ancillary services premium incorporated in clause 3.14.5A(f) were simply set at 0.15 (in a similar manner to the calculation of BVG) rather than being divided by the number of trading intervals in an hour, it would be necessary for the costs formula in clause 3.14.5A(d) to divide (MWE x BVAS) by two. This is because prices in the MSPS are determined for each 30 minute trading interval while the benchmark value is expressed in $/MWh which then needs to be translated into a value for each half hour.

A similar adjustment is not required in relation to the estimated costs of generation because the 'adjusted gross energy' used to calculate trading amounts is expressed in MWh, and the regional reference price is expressed in $ per MWh (clause 3.15.6(a)). By contrast, the amount of ancillary services that a participant has been enabled to provide is expressed in MW and the ancillary service price is expressed in $ per MW per hour (clause 3.15.6A(a)).

Under normal conditions, NEMDE determines a clearing price every five minutes for each of the eight FCAS markets. This price is then used to determine payments to each of the FCAS providers using the formula: payment = MWE x CP/12. In this formula, MWE is the amount of MW enabled by NEMDE and CP is the clearing price for the service in that dispatch interval.

As the clearing price is defined as $ per MW per hour, consistent with clause 3.15.6A(a) of the NER, dividing the result by twelve brings the payment back in line with the five minute dispatch interval. Once the five minute payments have been determined, these are summed over a trading interval and expressed as half hourly payments for the purpose of recovery.[120] In the case of the MSPS, however, it would be appropriate (for now) to divide by two rather than 12.[121] Once the five minute settlement rule commences in 2021, it will be appropriate to divide by 12 - reflecting that there will be 12 trading intervals in each hour, rather than two as at present.[122]

Given this, clause 3.14.5A(f) in the final rule uses a formula that enables the above adjustment to be made without requiring a change to the NER. In the near term, the value of 'n' (the number of trading intervals per hour) will be two. Once five-minute settlement commences, the value of 'n' will change from two to 12.

120 AEMO, *Guide to Ancillary Services in the National Electricity Market*, April 2015, p. 11

121 Each MSPS consists of two sets of 48 trading interval prices for each region and market (energy and eight FCAS markets). One set applies to weekday day-types, other than public holidays in the majority of the region. The other set applies to weekend daytypes and public holidays in the majority of the region. Each trading interval price is calculated as the historical average of prices in the EMMS database for the relevant region, market, day-type and trading interval over the 28 day period to the end of the NEM billing week (end of Saturday). AEMO, *Guide to the Market Suspension Pricing Schedule*, July 2017, p 4.

122 The five-minute settlement rule change can be viewed at https://www.aemc.gov.au/rule-changes/five-minute-settlement

4.3 Scheme administration

This section discusses issues relating to the administration of the new compensation framework.

4.3.1 Responsible market body

The AEMO rule change request would, if made as proposed, make the AEMC responsible for processing market suspension compensation claims, consistent with the APP model. However, the final rule confers responsibility for calculating compensation and processing claims on AEMO.

Given that the new framework involves the automatic calculation of compensation based on data held by AEMO, the Commission considers it most efficient to have AEMO undertake this function. AEMO has well established practices for calculating compensation in connection with directions, and engaging independent experts to assess claims for additional costs. AEMO is also responsible, under both the APP and directions compensation framework, for recovering the cost of compensation payments from market customers.

Extending AEMO's role to include the MSPS compensation framework is not expected to have significant resource implications, noting that two market suspension events have occurred since the inception of the NEM in 1998. While there will be additional work involved in developing the Market Suspension Compensation Methodology and, annually, updating the schedule of benchmark values, this will be offset by avoiding or reducing the volume of work generated by the need to issue directions during any future market suspension. Finally, the administrative burden associated with the proposed framework is much less than if each claim had to be assessed individually, consistent with the APP model.

4.3.2 Referring claims to independent experts

The draft rule proposed that claims for additional costs be referred to an independent expert where they exceed $50,000 (claims below this threshold would be processed in-house by AEMO). This is similar to the approach used in the directions compensation framework whereby claims are referred to an independent expert if they meet certain thresholds. In particular, AEMO is required to refer claims for additional compensation to an independent expert if the claim exceeds $20,000 *and* the 'additional intervention claim' exceeds $100,000.[123]

'Additional intervention claim' is defined in clause 3.12.2(k) as the total of:

1. the sum of the *affected participant's adjustment claims* [viz. where a participant affected by a direction does not agree with AEMO's estimation of automatically payable compensation] and *market customer's additional claims* [where a market customer with a scheduled load is affected by a direction and does not agree with AEMO's estimation of automatically payable compensation] in respect of a AEMO intervention event, or in

123 NER, clause 3.15.7B(c)(1)

respect of, in AEMO's reasonable opinion, a series of related AEMO intervention events; plus

2. the total claims by *Directed Participants* pursuant to clauses 3.15.7B(a), 3.15.7B(a1) and 3.15.7B(a2) in respect of that AEMO intervention event, or in respect of that series of related AEMO intervention events.

The draft rule adopted a higher threshold of $50,000 reflecting that the $20,000 figure has been in the rules since the inception of the NER in 2005 and is not indexed. Claims for less than $50,000 are considered too small to warrant incurring the additional expense associated with engaging an independent expert.

The second limb of the directions referral test (namely, whether the $100,000 'additional intervention claim' threshold has been met) was not incorporated in the draft rule on the basis that the MSPS compensation framework focuses on scheduled generators who incur loss when MSPS prices are low. It does not compensate affected participants or market customers as occurs following the issue of directions.

Under the draft rule, claims for additional costs are also referred to an independent expert in the event that AEMO considers a claim to be unreasonable. Again, this reflects the approach adopted in the directions compensation framework.[124]

In response to the draft determination, ERM and EnergyAustralia both expressed concern regarding the $50,000 threshold above which AEMO would be required to refer claims for additional compensation to an independent expert (with consequences for claimants in terms of administrative fees payable).[125] Both suggested that the threshold should apply per trading day and/or that a higher threshold should apply for an entire market suspension event or billing period.

The Commission does not support the approach proposed by ERM and EnergyAustralia on the basis that the formula for calculating compensation focuses on the costs incurred (net of revenue earned) over the entire MSPS period: it does not have regard to individual trading days. Using a per trading day threshold could have unintended outcomes, such as encouraging bidding behaviour designed to keep compensable costs below the daily threshold and thus avoid higher administrative fees.

Rather than adopt a daily threshold and/or add a higher threshold for the entire market suspension event or billing period, the Commission has decided to amend clause 3.14.5B(f) such that AEMO has discretion to refer claims above $50,000 to an independent expert but is not required to do so. This will allow AEMO to deal in-house with claims which, while large, are not so complex as to warrant engaging an independent expert (a process which is expected to attract a higher administrative fee for claimants, noting that the setting of fees is a matter for AEMO to determine in the Market Suspension Compensation Methodology).

In cases where AEMO considers a claim to be unreasonable, the obligation to refer such claims to an independent expert will remain as per the approach in the draft rule (it will not

124 NER, clause 3.15.7B(d)(2)

125 See p. 4 of the ERM submission and p. 3 of the EnergyAustralia submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

become discretionary). The Commission does not share ERM Power's concern that participants will be discouraged from making a claim due to the obligation on AEMO to refer to an independent expert claims which are considered unreasonable. On the contrary, the Commission considers that the current approach will encourage claimants to ensure that their claims are sound and well supported. As such, no changes to this provision are considered necessary.[126]

The Commission notes that AEMO does not have an incentive to set MSPS administrative fees at such a level as to discourage claims for additional compensation following a MSPS period.[127] This is because doing so could inadvertently incentivise generators to withdraw and await direction in order to avoid the administrative fees payable by claimants for additional compensation under the MSPS compensation framework. (Such an outcome would create more work for AEMO and be contrary to the objective of the rule change request.) However, moving from the MSPS to the directions compensation framework would mean that claimants become subject to the threshold - currently set at $5,000 per trading interval - below which claims for additional compensation cannot be made. This threshold is discussed further below.

4.3.3 No threshold applicable as in directions compensation framework

The directions compensation framework currently includes a threshold of $5,000 per trading interval below which a directed participant may not make a claim for additional compensation (i.e. additional to the automatically calculated 90th percentile price compensation).[128] The rationale for the threshold is that, if the loss per trading interval is less than $5,000, this amount is immaterial and does not justify the costs of determining a compensation payment.[129]

Recent discussions with stakeholders have explored whether this should be amended such that the threshold applies per 'AEMO intervention event' (a direction being issued or the RERT being exercised) rather than per trading interval.[130] If made, this change would result in more additional compensation being payable to directed participants (and passed onto

126 It is worth noting that 'reasonable' in this context has a particular application. For directions claims below the relevant thresholds, clause 3.15.7B(c)(2) requires AEMO to determine if the claim is reasonable and, if so, pay the amount claimed. There is no discretion for AEMO to pay an amount greater or smaller than that sought by the claimant. Thus, AEMO does not have the ability to determine that a claim is 'reasonable' (in a general sense) and then determine the quantum of compensation that should be paid. The decision is binary in nature - AEMO must either accept that the quantum of compensation sought is reasonable and pay it, or refer the claim to an independent expert. Any alterations to this approach could create the potential for 'claim creep' - incentivising claimants to include costs that are not well supported in the knowledge that AEMO could still consider the claim to be 'reasonable' in a general sense but not pay the full amount sought. To avoid this undesirable outcome, clause 3.14.5B(g)(2) in the final rule mirrors the equivalent provision in the directions compensation framework: namely, where claims are considered unreasonable, they must be referred to an independent expert.

127 ERM Power expresses concern that claimants may lower their claims to avoid the (potentially) higher administrative fees associated with having claims referred to an independent expert: see p. 4 of their submission in response to the draft determination.

128 NER, clause 3.15.7B(a4)

129 SW Advisory & Endgame Economics, *Review of Intervention Pricing - Final Report prepared for AEMO*, October 2017, p. 51. This is available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Othermeetings/Intervention-Pricing-Working-Group in the meeting pack for Meeting 1

130 The Intervention Pricing Working Group established by AEMO has discussed a number of possible rule changes, including changes to the $5,000 threshold. See meeting papers available at https://www.aemo.com.au/Stakeholder-Consultation/Industryforums-and-working-groups/Other-meetings/Intervention-Pricing-Working-Group See in particular item 4.1 in the meeting pack for meeting 5.

consumers), particularly where the intervention event comprises a large number of trading intervals - as has occurred in recent times.[131]

Given that the current approach in the directions compensation framework may change, and noting that the $5,000 figure has been in the rules since 2005 and is not indexed, the final rule adopts a different approach. Rather than impose a threshold per trading interval or per market suspension event, the final rule empowers AEMO to recover an administrative fee where an eligible claimant lodges a claim for additional compensation. (No fee would apply to the automatic calculation of compensation.)

This administrative fee would be set out by AEMO in the Market Suspension Compensation Methodology and could be tiered, depending on whether or not an independent expert is needed to assess the claim. In addition to helping AEMO recoup some of its costs, the fee will also help deter claimants from seeking immaterial sums of compensation, the processing of which would impose costs on AEMO (and thus all market participants). In this way, the fee will serve the same purpose as the threshold currently included in the directions compensation framework.

In setting the fee, regard will need to be had for the relative cost to claimants under both the MSPS and directions compensation framework. If the cost of seeking additional compensation under the MSPS compensation framework is comparatively high, participants will have an incentive to wait for a direction and thus avoid fees associated with the MSPS compensation framework. This would be contrary to AEMO's objective in seeking the rule change.

AGL was the only stakeholder to comment on this part of the compensation framework in its submission, stating it is 'comfortable with the absence of the $5,000 threshold that applies in the directions framework'.[132]

4.4 Compensable costs

The costs that are compensated under the existing NER compensation frameworks are:

- for directions, direct costs and loss of revenue (these can be claimed via a claim for additional compensation – noting that the initial compensation payment is based on the 90th percentile price rather than on costs facing individual generators)[133]
- for APP, direct costs and opportunity costs.

While different terms are used, there is some commonality between the reference to 'loss of revenue' in the directions framework and 'opportunity costs' in the APP framework.

The APP Compensation Guidelines prepared by the AEMC in accordance with NER clause 3.14.6(e) provide examples of when a participant may incur opportunity costs. 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

131 For example, one recent intervention event lasted three weeks - from 23 April to 14 May 2018.

132 See p. 1 of the AGL submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

133 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'.

are uncapped (and high). 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.

While the APP 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. This indicates 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 incurred due to an energy direction have in the past been rejected due to clause 3.12.2(j)(3) of the NER.[134] 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. Through the Intervention Pricing Working Group, AEMO has queried whether this is appropriate.[135]

The question arises as to what costs should be compensable under the proposed MSPS compensation framework. Under the draft rule, compensation additional to the automatically calculated component was only payable in relation to direct costs. The submission from AGL in response to the consultation paper supported this approach, stating that only direct costs should be compensable, 'where those direct costs have been incurred as a result of acting in accordance with verbal instructions or requests from AEMO during a period of market suspension'.[136] The final rule is unchanged in this regard.

Compensation for opportunity costs is not supported since they do not form part of the directions compensation framework and the objective of the rule change request is to remove the incentive for generators to await a direction rather than participate voluntarily – hence the directions compensation framework is a key reference point.

Compensation for loss of revenue is also not included in the final rule (subject to one exception discussed below in section 4.6). This reflects that the situation during a MSPS period can be distinguished from the situation when a generator is directed to provide services on three counts:

- the directed generator is not free to optimise its position, a factor that is not present absent a direction
- the price during an MSPS is known in advance, and is not impacted by bidding behaviour

134 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.

135 See AEMO document titled "4.1 IPWG Rule Change Proposals - Meeting 5" in the Meeting 5 meeting pack available at https://www.aemo.com.au/Stakeholder-Consultation/Industry-forums-and-working-groups/Other-meetings/Intervention-PricingWorking-Group

136 See AGL submission, cover letter and pp. 2-5, available at https://www.aemc.gov.au/sites/default/files/2018-06/AGL-%20received%2022%20June%202018.pdf

- there is no intervention pricing run (as occurs when a direction is issued) that would provide a counterfactual on the basis of which to calculate loss of revenue

The Commission also notes that, to date, there has only been one claim for loss of revenue resulting from a direction (issued on 1 December 2016). Thus, from a practical viewpoint, precluding claims for loss of revenue may have little impact on participants.

4.5 Eligibility for compensation

The draft rule conferred eligibility for MSPS compensation only on scheduled generators and ancillary service providers (with respect to ancillary service generating units which are also scheduled generating units) in the suspended region. This was on the basis that these are the parties who:

- would be directed by AEMO to provide services if the need were to arise during a MSPS period (noting that the objective of the MSPS compensation framework is to remove the incentive for such parties to await direction), *and*
- can be expected to incur direct costs (e.g. fuel costs) in providing services during a MSPS period.

While AEMO has power to direct a wide range of market participants, AEMO advises that it has only issued directions to scheduled generators and, on two ocassions, to Basslink. (On both these occassions, the direction was for Basslink to turn off its frequency controller in order to maintain power system security in the NEM.[137]) AEMO advises that it has not issued directions to semi-scheduled and non-scheduled generators. However, if directions were to be issued to such participants during a future MSPS period, they would be entitled to be compensated for their services at the 90th percentile price under the directions compensation framework. On the other hand, they would not be eligible for MSPS compensation in the event their short run costs exceeded the revenue they earned from the MSPS.

The new framework's focus on scheduled generators also reflects that many semi-scheduled and non-scheduled generators have very low SRMC and thus are unlikely to be out of pocket (in terms of direct costs) as a result of the application of the MSPS.

The Commission has opted not to include ancillary service loads in the definition of market suspension compensation claimant, instead limiting eligibility to ancillary service generating units that are also classified as scheduled generating units. While it is recognised that ancillary services are provided by a growing range of providers on both the supply and demand side of the market, it is not clear what direct costs would be incurred by ancillary service loads during a MSPS period that would warrant compensation additional to the revenue provided by the MSPS price for ancillary services.

Similarly, where ancillary services are provided by a generating unit that is not a scheduled generating unit, it is unclear what direct costs would be incurred during a MSPS period such as to warrant the payment of compensation in addition to the revenue provided by the MSPS.

137 Directions reports are at https://www.aemo.com.au/-/media/Files/PDF/NEM_Event_Direction_to_Basslink_11_April_13.pdf and https://www.aemo.com.au/-/media/Files/PDF/NEM-Event—Direction-to-Basslink-and-a-Tasmanian-Generator—16-December2014.pdf

As such, the definition of market suspension compensation claimant excludes ancillary service generating units that are not also scheduled generating units.

The same logic applies when considering the potential for a demand response mechanism to be included in the NER in future. While such a mechanism may be capable of direction by AEMO, it is not clear that direct costs would be incurred during a MSPS period such as to warrant the payment of additional compensation.

The Commission recognises that this focus on scheduled generators and ancillary service providers differs from that adopted under the directions and APP compensation frameworks. However, a different approach is considered appropriate given the conditions that exist during MSPS periods and noting the objective of the rule change request.

For example, under the directions compensation framework, an 'eligible person' who incurs loss due to changes in interconnector flows could be eligible for compensation.[138] Similarly, affected participants (such as generators whose dispatched quantity was reduced in response to a direction) are entitled to compensation. In both cases, the compensable loss arises because a change has occurred as a result of the direction. In the case of a MSPS period (and assuming no direction has been issued), there is no relevant change and as such no relevant loss that needs to be compensated. Nor is there a counterfactual (provided by the 'intervention pricing run') on the basis of which to determine the compensable loss.[139]

For the same reason, the final rule does not confer eligibility for compensation on market customers with scheduled load. Such customers are able to be compensated under both

- the APP framework - if the application of the administered floor price (AFP) results in prices higher than that at which the scheduled load would otherwise have consumed energy, and
- the directions framework - if AEMO determines that the scheduled load would have consumed a different amount of energy but for the direction.

As noted earlier, there is no relevant change in the case of a market suspension event that would create a compensable loss for scheduled loads. The prices in the MSPS are a function of prices in the preceding four weeks – meaning that the scheduled load will be responding to prices similar to those it has seen before. No compensation is considered to be warranted in such instances.

In relation to non-scheduled generators and scheduled loads, AGL's submission in response to the consultation paper considered that such parties should be eligible for compensation but only if 'the participant has incurred direct costs as a result of acting in accordance with verbal instructions or requests from AEMO/AEMO control room during a period of market

138 Eligible persons are included in the definition of 'affected participant' in chapter 10 of the NER.

139 When AEMO issues a direction, it is required to implement 'intervention pricing' so as to preserve the market signals (prices) that would have been sent had the intervention/direction not occurred. (The exception is where a direction relates only to a localised as opposed to region-wide issue. In such cases, intervention pricing is not required.) To implement intervention pricing, AEMO runs NEMDE twice - once to set dispatch targets, and once to set prices. The latter run excludes the effect of the direction and thus provides a means to estimate compensation payable to affected participants. See clause 3.9.3 of the NER. However, clause 3.14.5(c)(2) provides that, where a direction is issued during a MSPS period, prices in the MSPS are not to be adjusted in accordance with normal intervention pricing requirements.

suspension'.[140] As noted above, it is not clear what direct costs would be incurred by such parties during a MSPS period such as to warrant the payment of compensation. Accordingly, they are not included in the definition of market suspension compensation claimant.

4.5.1 Losses due to scaling

Scaling can occur during a MSPS period and an APP. The purpose of price scaling is to prevent, or manage, the accumulation of negative interregional settlement residues.

The NER 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: clause 3.14.5(f). 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. During the SA market suspension, prices were scaled in Victoria and – to a much lesser degree – New South Wales and Queensland as a result of the application of the MSPS in SA.

Under the APP framework, if prices in one region are set by the APC or AFP, prices in neighbouring regions are also scaled to prevent or manage negative inter-regional settlement residues.[141] 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 and non-scheduled generators, market participants in respect of scheduled loads, and scheduled network service providers. As noted previously, there has only been one compensation claim in respect of an APP and this did not involve losses due to scaling.

Given the focus of the MSPS compensation framework on direct costs, and the exclusion of loss of revenue claims, the draft rule did not provide for compensation to be paid to participants in neighbouring regions who incur loss due to scaling. The draft determination noted that MSPS prices are known in advance and thus market participants can, where practicable, optimise their position. It is also envisaged that MSPS pricing will be automated in future, making it easier for market participants to adjust their bids to take MSPS prices and scaling into account.[142]

4.5.2 Stakeholder views in response to the draft determination

In response to the draft determination, ERM notes that, due to the impact of scaling, participants in neighbouring regions 'may also be dispatched by AEMO at regional reference prices below actual costs. During the 2016 South Australian market suspension event, settlement prices in the remaining four NEM regions were all adjusted to lower values for a

140 See p. 4 of AGL submission available at https://www.aemc.gov.au/sites/default/files/2018-06/AGL-%20received%2022%20June%202018.pdf

141 NER, clause 3.14.2(e)

142 See AEMO, *Market Suspension Change Proposals - Discussion Paper*, April 2017, p. 12, available at https://www.aemc.gov.au/sites/default/files/2018-05/Supplementary%20information_2.pdf

number of trading intervals due to the impact of [scaling]... As such, the proposed compensation framework has the potential to impact participant bid availability decisions in regions outside the region in which market suspension has been invoked resulting in potential power system security and supply reliability issues in regions not directly subject to market suspension at that time. In considering the proposed compensation framework, we believe the potential for this outcome also needs to be carefully considered by the Commission'.[143]

The approach adopted in the draft determination was not to provide compensation for such participants on the basis that the focus of the compensation framework was on direct costs incurred and not on loss of revenue. This approach was consistent with the AGL submission in response to the consultation paper (AGL was the only stakeholder to address this issue). AGL stated that generators in neighbouring regions should not be able to claim compensation if they incur a loss due to scaling as this is not a direct cost.[144]

In its submission in response to the draft determination, ERM notes that AEMO's proposal[145] to impose a $300 cap on prices in the MSPS (published in September 2018, following release of the draft determination) 'has implications not only for the region subject to market suspension but also all regions where the RRP is impacted by price scaling'.[146]

Capping MSPS prices at $300/MWh may mean that scaling in neighbouring regions applies more frequently than would otherwise occur, all else being equal. This could occur for example when high demand in a neighbouring region results in high spot prices which are then scaled down so as not to exceed the MSPS price in the suspended region, adjusted for losses.

During the market suspension event in South Australia in late 2016, prices in Victoria were scaled in 93 out of 672 trading intervals (~14% of trading intervals or TIs). In four TIs (0.6% of TIs), the level of scaling exceeded $100/MWh, while in 23 TIs (3.4% of TIs) the scaling was > $10/MWh but <$100/MWh. The majority of the 93 affected TIs involved minor amounts of scaling – in the order of a few dollars (50 TIs involved scaling of <$5/MWh while 16 TIs involved scaling of >$5 but <$10/MWh). Of concern are those periods when the impact of scaling was significant. For example, towards the end of the market suspension event, prices in Victoria were scaled in four periods as follows:

Figure 4.7: Impact of MSPS scaling on Victorian spot prices during SA market suspension

Trading interval	Original Vic RRP	Scaled Vic RRP
11 October 6.30am	$280	$54

143 See p. 2 of the ERM submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

144 See p. 4 of AGL submission in response to the consultation paper, available at https://www.aemc.gov.au/sites/default/files/2018-06/AGL-%20received%2022%20June%202018.pdf

145 AEMO, *Market Suspension Pricing Schedule - draft report and determination*, September 2018 available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2018/Market-Suspension-Pricing/Market-Suspension-Pricing-Schedule-Draft-Report-and-Determination.pdf

146 See p. 3 of the ERM submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

11 October 7.00am	$291	$76
11 October 7.00pm	$227	$96
11 October 7.30pm	$191	$70

Source: AEMO data

As can be seen, during the morning and evening peak, high spot prices in Victoria were substantially scaled down in response to low MSPS prices in South Australia. (MSPS prices reflect the average of prices over the preceding four weeks, rather than the supply demand conditions that apply during the market suspension event. They also reflect the generation mix in the region in which the prices are averaged to produce the MSPS. The high proportion of renewable energy in South Australia can result in low to negative spot prices when demand is low and wind output is high.)

ERM did not raise this issue in their original submission but in their latest submission they have urged the Commission to consider this carefully in the final determination. ERM is concerned that scaling in neighbouring regions may prompt higher cost generators in those regions to withdraw and await direction.[147]

This is a valid concern which may be exacerbated by AEMO's intention to automate MSPS pricing in future – such that peaking plant may de-commit in response to price scaling and await direction. This would be contrary to the objective of the rule change request (namely to remove the incentive for generators to withdraw and await direction at a time of already heightened control room stress).

The draft rule narrowly defined 'eligible claimant' such that only scheduled generators and ancillary service providers (in respect of ancillary service generating units that are also classified as scheduled generating units) in the suspended region would be entitled to compensation. However, the Commission has decided that the definition of eligible claimant (referred to in the final rule as 'market suspension compensation claimants') should be extended to include scheduled generators in neighbouring regions where prices are scaled as a result of clause 3.14.5(f). This would only apply during those intervals that are subject to scaling, rather than throughout the entire MSPS period. Under this revised approach, such generators would be compensated based on benchmark values if their deemed costs during those intervals exceed the revenue they receive as a result of the scaled price. This is designed to remove the incentive for generators to withdraw capacity when scaled prices are insufficient to cover their short run costs.

To remove any residual incentive for such generators to withdraw and await direction, the 'no forum shopping provision' (clause 3.15.7(d1)) will apply to scheduled generators located in neighbouring regions who are directed to provide services during intervals when scaling

147 See p. 2 of the ERM submission available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

applies (in addition to scheduled generators in the suspended region who are directed to provide services during a MSPS period).

These changes are achieved by adopting a new definition of 'market suspension compensation claimant' (replacing the term 'eligible claimant' in the draft rule). The new definition covers both those scheduled generators and ancillary service providers located in the suspended region and those scheduled generators located in neighbouring regions where dispatch prices are affected by scaling. Changes have also been made to the definition of 'market suspension pricing schedule period' so as to capture both the entire MSPS period (relevant for calculating compensation for parties located in the suspended region) and those intervals during which prices are affected as a result of scaling (relevant for calculating compensation for parties in neighbouring regions who incur loss due to scaling).

4.6 Preventing forum shopping

Where an eligible claimant under the MSPS compensation framework is directed by AEMO to provide services during a MSPS period, that participant will be compensated automatically using the benchmark value approach set out in clause 3.14.5A of the final rule, rather than using the 90th percentile price approach set out in clause 3.15.7(c) of the NER. This removes the residual risk that a generator may prefer to await direction from AEMO, rather than participate voluntarily and be compensated under the MSPS compensation framework, in order to maximise the compensation payable for services provided.

This residual risk is a function of the gap between the benchmark value for a given category of generator and the 90th percentile price in a given region at a given time. For example, having regard for the estimated SRMC figures and 90th percentile prices shown in figure 4.1, a typical combined cycle gas plant could expect to receive more compensation under the 90th percentile price approach than under the benchmark value approach. Conversely, the most expensive open cycle gas plants would expect to receive more compensation (automatically calculated) under the MSPS compensation framework than under the directions framework (since the benchmark value of the most costly plants will exceed the 90th percentile price).

As discussed in the Reliability Frameworks Review Final Report, the current use of directions in SA raises questions as to whether the directions compensation framework strikes an optimally efficient balance between, on the one hand, fairly compensating directed parties for their services and, on the other, the level of compensation costs imposed on consumers.[148]

A recent AER compliance report also raises questions about generator behaviour in the lead up to directions being issued: "We are currently considering the conduct of some scheduled generators who have advised AEMO of their intention to desynchronise at shorter notice than is required by clause 4.9.7(a) of the Electricity Rules. Further, we are examining whether this has led to AEMO issuing directions to generators to remain synchronised, to ensure the

148 AEMC, *Reliability Frameworks Review - Final Report*, July 2018, p. 106.

market remains in a secure operating state. AEMO has observed an increase in the frequency of this behaviour over recent months."[149]

In order to achieve AEMO's objective in proposing the rule change (i.e. to remove the incentive for a generator to await direction rather than participate voluntarily), the final rule excludes eligibility for 90th percentile price compensation only in cases where a direction is issued during an MSPS period to an eligible claimant. This does not affect in any way the ability of AEMO to issue directions, nor does it remove all rights to compensation: it simply changes the basis on which automatically calculated compensation is determined for parties who are eligible claimants under the MSPS compensation framework.

If a directed participant is not adequately compensated pursuant to the benchmark value approach, it can lodge a claim for additional compensation. This would be done pursuant to clause 3.15.7B (which is part of the directions compensation framework) rather than under clause 3.14.5B of the final rule (which is part of the MSPS compensation framework).

Under clause 3.15.7B, a directed participant can claim for losses (e.g. loss of revenue) that cannot be claimed under clause 3.14.5B of the final rule (which refers only to direct costs and does not include loss of revenue). Further, the list of costs in clause 3.15.7B(a3) includes some items (maintenance work acceleration and delay costs) that are not included in the equivalent provision in the MSPS compensation framework (clause 3.14.5B(d) of the final rule). Such costs would not generally be incurred absent some form of compulsion, hence they are not included in the MSPS compensation framework.

Despite the exclusion of 90th percentile compensation, the approach adopted in the final rule means that a claim for loss of revenue could still be made where a direction is issued during an MSPS period. For example, if a participant were directed to provide ancillary services (and not generate energy) at a time when MSPS ancillary service prices were low and energy prices were high, it could lose revenue due to its inability to generate energy. In such a case, a participant could lodge a claim for loss of revenue, using the process set out in clause 3.15.7B.

In their submissions in response to the draft determination, both AGL and ERM expressed support for this provision designed to prevent forum shopping.[150]

4.7 Cost recovery

The draft rule provided that compensation costs under the MSPS compensation framework would be recovered from market customers in the suspended region, consistent with the approach to recovering APP compensation costs.[151] This approach was supported by Snowy Hydro in its submission to the consultation paper.[152]

149 AER, *Quarterly Compliance Report: National Electricity and Gas Laws*, *1 January - 31 March 2018*, p. 7, available at https://www.aer.gov.au/system/files/Quarterly%20Compliance%20Report%20January%20-%20March%202018%20.pdf

150 See p. 1 of the AGL submission and p. 1 of the ERM submission, both available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

151 NER, clause 3.15.10

152 See p. 2 of the Snowy Hydro submission in response to the consultation paper, available at https://www.aemc.gov.au/sites/default/files/2018-06/Snowy%20Hydro.pdf

This cost recovery approach differs from the directions compensation framework under which compensation costs are recovered from one or more region/s based on the benefit provided by the direction.[153] The latter approach was supported by AGL in its submission to the consultation paper.[154]

For simplicity, the draft rule proposed that cost recovery follow the APP model - save for any additional costs claimed by a directed participant pursuant to clause 3.15.7B (rather than clause 3.14.5B of the draft rule). In such cases, the draft rule provided that the compensation cost would be recovered in accordance with the usual approach to directions compensation payments (i.e. applying the regional benefit test).

4.7.1 Cost recovery in final rule

In its submission to the draft determination, AGL maintained its position that 'compensation costs should be recovered from any neighbouring region that receives a benefit, and not from the suspended region alone. We appreciate that the AEMC has steered away from this for simplicity, however given market suspension occurs far less frequently than the issuance of directions, we do not consider it would be particularly burdensome to apply in the market suspension compensation framework'.[155]

The Commission has decided to streamline the cost recovery provisions so that a single process applies to both standard MSPS compensation payments and additional compensation payments to directed participants who are also market suspension compensation claimants. This will also resolve an issue concerning the differing timeframes applicable to the two cost recovery models incorporated in the draft rule (APP and directions). If left unchanged, these differing timeframes would complicate the administration of the MSPS compensation framework. Adopting the AGL approach resolves this issue by managing all cost recovery through a single framework.

Adopting the regional benefit test that forms part of the directions framework is also consistent with the decision to extend eligibility for compensation to include those scheduled generators in neighbouring regions who incur loss due to price scaling. It is considered appropriate (subject to the regional benefit test and the facts in each case) to recover the cost of compensating generators in neighbouring regions from customers in that region.

The Commission notes that the cost recovery approach adopted in clause 3.15.8A of the final rule differs in two respects from the similar provision in clause 3.15.8 (being the cost recovery provision applicable to directions). In particular, clause 3.15.8A omits the reference to loads in respect of which a dispatch bid has been submitted. Including a reference to such loads is not required on the basis that, for directions, scheduled loads are eligible for compensation under clause 3.12.2. Such loads are not eligible to be compensated under the MSPS compensation framework and as such it is not necessary to exclude them so as to

153 NER, clause 3.15.8(b)

154 See p. 5 of the AGL submission in response to the consulation paper, available at https://www.aemc.gov.au/sites/default/files/2018-06/AGL-%20received%2022%20June%202018.pdf

155 See p. 2 of the AGL submission, available at https://www.aemc.gov.au/rule-changes/participant-compensation-following-market-suspensi

avoid any overlap between clause 3.15.8 and the scheduled load compensation formula set out in clause 3.12.2.

The second difference relates to the definition of 'E' in the formula set out in clause 3.15.8A(b). As noted in clause 3.15.8A(d), where the value of 'E' is positive it will be deemed to be zero. The purpose of this formula is to apportion the cost of MSPS compensation to market customers by reference to their market share. The final rule adjusts the formula to set the value of 'E' to zero where a market customer is a net exporter to the grid. This is designed such that these market customers are not liable to make a contribution to the MSPS compensation cost (consistent with the position of generators) but neither are they eligible to receive a payment from AEMO.

4.8 How the final rule achieves the NEO

The Commission considers that the final rule will efficiently incentivise scheduled generators to voluntarily (without direction) assist AEMO in restoring or maintaining electricity supply during a MSPS period. This is in the long term interests of consumers and as such will, or is likely to, promote the achievement of the NEO. By contrast, the AEMO proposed APP model does not appear likely to achieve this outcome, while the 90th percentile price approach proposed by some stakeholders in response to the consultation paper could create perverse incentives leading to inefficient bidding behaviour, dispatch outcomes and compensation payments. Such an approach would be contrary to the NEO.

The Commission considers that the final rule strikes a fair balance between the interests of scheduled generators and the interests of consumers (who bear the cost of compensation payments). It creates appropriate incentives for scheduled generators and ancillary service providers to provide services in accordance with AEMO dispatch instructions (as opposed to directions) during a market suspension, while reducing the level of compensation payments that are recoverable from consumers.

The final rule also strikes an efficient balance between accuracy and administrative burden. While both the APP approach and the final rule take as their starting point the costs facing individual generators, the calculation of compensation under the final rule will (at least in the first instance) be automated while the APP approach is bespoke and costly. This means that the administrative cost associated with the final rule (both for the responsible market body and the applicant) is far lower than if each claim had to be processed individually using the APP model.

While the accuracy of the APP model is greater than that of the final rule, this trade-off is considered reasonable in order to reduce overall costs. The accuracy of the final rule is greater than that of the 90th percentile approach because it takes the estimated costs of each generator as its starting point, rather than calculating compensation on the basis of the 90th percentile price – which is a function of the generation mix in each region and the market conditions in the previous 12 months.

4.9 Conclusion

The expected costs, benefits and impacts of the final rule are difficult to quantify with any precision, given:

- the historical infrequency of market suspension events
- the difficulty of predicting the circumstances that might give rise to, and follow from, a market suspension event
- the impossibility of estimating how much compensation may be payable as a result of the application of the MSPS.

As AEMO notes in its rule change request, 'the financial impacts [during a market suspension event] are participant, event and timing dependent'.[156] (Indeed, this statement is also true of APPs and directions.)

While precise quantitative analysis is not possible, it is possible to compare the final rule's costs and benefits relative to the counterfactual scenario that could be expected to arise if the rule change were not to proceed. In the (ongoing) absence of a MSPS compensation framework, it is reasonable to expect that – during any future MSPS period – a generator with higher costs may await a direction from AEMO rather than participate voluntarily.

The cost of the directions compensation framework thus provides a reference point against which to compare the costs and benefits of the final rule. To the extent that the final rule costs less than the directions compensation framework, it can be said to deliver a benefit.

It is important that any evaluation of costs and benefits include those factors that are difficult to monetise – such as the operational risks associated with implementing directions (including the potential for perverse market outcomes[157]) and the benefits to consumers and the economy generally of promptly restoring and/or maintaining a secure and reliable electricity supply.

The costs of administering the new compensation framework also need to be considered. Administrative costs should be kept as low as practicable to ensure the new framework is efficient. This will reduce the costs passed on to consumers.

The Commission considers that the final rule achieves AEMO's objective in requesting the rule change, minimises perverse incentives that could lead to inefficient bidding and dispatch outcomes, and achieves a fair balance between the interests of market participants and consumers. As such, the final rule will, or is likely to, contribute to achieving the NEO.

156 AEMO, *Rule change proposal: Market suspension rule changes - participant compensation*, p. 7.

157 For example, the use of intervention pricing following a direction to a South Australian generator in February 2017 created unexpected price spikes (reaching the market price cap) in NSW and Queensland. AEMO considers that, had the direction not been issued, high prices should have been confined to South Australia. This event triggered a review of intervention pricing: see SW Advisory and Endgame Economics, *Review of Intervention Pricing, Final Report prepared for AEMO*, 4 October 2017, p. 19.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFP	Administered floor price
APC	Administered price cap
APP	Administered price period
CCGT	Combined cycle gas turbine
Commission	See AEMC
EMMS	Electricity market management system
FCAS	Frequency control ancillary services
IPWG	Intervention Pricing Working Group
ISP	Integrated System Plan
MSPS	Market Suspension Pricing Schedule
MW	megawatt
MWE	megawatts enabled (to provide ancillary services)
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National electricity objective
NTNDP	National Transmission Network Development Plan
OCGT	Open cycle gas turbine
RERT	Reliability and Emergency Reserve Trader
SA	South Australia
SRMC	Short run marginal cost

A SUMMARY OF ISSUES RAISED IN SUBMISSIONS TO THE CONSULTATION PAPER

This appendix sets out the issues raised in the first round of consultation on this rule change request and the AEMC's response to each issue.

Table A.1: Summary of issues raised in submissions

STAKEHOLDER	ISSUE	AEMC RESPONSE
Australian Energy Council	To be effective, the compensation framework should be financially favourable, easily accessible and predictable. Suggests a bespoke or hybrid compensation framework would be preferable to the APP model. (p.1)	The final rule creates a framework that is predictable and easily accessible. It is financially fair but not so favourable as to create perverse incentives.
ERM Power	Does not support compensation based on 90th percentile price. Such compensation is not sufficient to compensate the most costly peaking plants but increasing the percentile price will result in excessive costs to consumers (p. 2). Supports APP compensation framework as it will mean 'consumers only pay compensation which accurately reflects the costs incurred' (pp. 2-3).	The final rule bases compensation on estimated costs incurred, rather than a percentile price which is not linked to costs. However, the final rule avoids the administrative costs associated with the APP model by using cost estimates instead of requiring claimants to substantiate (and a market body to confirm) actual costs.
EnergyAustralia	Supports a framework that balances costs to consumers with the need to incentivise generators to supply power without being directed (p. 1).	The final rule strikes a fair and efficient balance between generator and consumer interests.

STAKEHOLDER	ISSUE	AEMC RESPONSE
	Extreme high or low prices in the MSPS can lead to disorderly bidding and inefficient outcomes. Placing an upper and lower bound on prices in the MSPS coud help (p. 2).	This is beyond scope of the rule change request. The AEMC suggested EA make a submission to the AEMO consultation process which is currently looking at this issue.
	AEMO is better placed than AEMC to process claims (p. 3).	The final rule confers responsibility for processing claims on AEMO.
	APP model lacks certainty re quantum of compensation and costs to participants, and is administratively inefficient (p. 3).	The final rule does not adopt APP model for these reasons.
	Supports a semi-automated compensation framework to provide certainty and reduce admin costs - e.g. use 90th percentile price or some equivalent, together with process for claiming additional costs not covered by the percentile price (p. 3).	The final rule includes an automated compensation component, and provides the right to claim additional costs where necessary. 90th percentile price is not supported due to potential for inefficient outcomes.
Snowy Hydro	Claimants should be able to claim direct and opportunity costs, and loss of revenue. (All points made on p. 2.)	The final rule focuses on direct costs, consistent with the aim of ensuring that generators are not out of pocket due to low MSPS prices. It is unclear how opportunity costs and loss of revenue would be calculated when MSPS prices are known in advance and there is no counterfactual (e.g. uncapped prices or intervention pricing run). Including these costs would make the process

STAKEHOLDER	ISSUE	AEMC RESPONSE
		expensive and unpredictable.
	A $5,000 threshold should apply per trading interval.	Rather than impose a threshold, an administrative fee can be recovered where a claimant seeks additional compensation (but is not payable for automatically calculated compensation). Noting the uncertainty about the length of a given market suspension, imposing a threshold per trading interval is not supported.
	Costs should be recovered only from customers in the suspended region.	The final rule adopts the regional benefit test approach in the directions compensation framework. This is consistent with extending eligibility for compensation to generators in neighbouring regions who are impacted by scaling and incur loss.
	'Any inconsistency between compensation frameworks under market suspension compared to directions would incentivise participants to take the less onerous approach.' Compensation should be automatic and set at 90th percentile price, with ability to claim additional costs (incl opportunity costs).	Compensation at 90th percentile price is not supported due to perverse incentives and costs to consumers. However automation is supported and included in the final rule.
	Where AEMC processes additional cost	AEMO to set out administrative fees in

STAKEHOLDER	ISSUE	AEMC RESPONSE
	claims in-house, it should not recover its costs from claimant. If an independent expert is retained, claimant should pay half the costs (capped at 50% of the gross amount of additional compensation payable to the claimant).	Compensation Methodology. These may be tiered for in-house and independent expert claims.
Origin Energy	Important to consider relative attractiveness of APP and directions compensation - including in relation to administrative burden and amount of potential compensation (p. 1).	Final rule does not apply APP model because it is considered too unattractive relative to the directions compensation framework.
AGL	Effect on incentives and transparency are important considerations in designing the framework (p. 1).	Final rule provides transparency and avoids perverse incentives by not over-compensating.
	Compensation should be limited to direct costs only (cover letter and pp. 2, 4, 5).	Final rule adopts this approach, except where participants are directed to provide services and then claim additional costs (in this case, they are able to claim loss of revenue in addition to direct costs).
	Forum shopping should not be allowed - costs should be recovered once only (p. 2).	Final rule deducts other compensation received from any additional cost compensation that is payable, and excludes 90th percentile compensation during MSPS periods.
	Supports the APP model, noting that	Final rule does not adopt APP model

STAKEHOLDER	ISSUE	AEMC RESPONSE
	market suspension is not expected to occur often; however only direct costs should be claimable, not opportunity costs (p. 3).	(which allows opportunity cost claims). Final rule does not allow opportunity cost claims (either as part of the automated process or additional cost claims).
	'There could be merit in embedding a base amount of compensation to provide predictability and certainty in the MSPS compensation process' but, given the expected rarity of market suspensions, a case by case approach is not concerning and automation is not an essential element (pp. 3-4).	Final rule embeds a base amount of automatically calculated compensation so that participants have confidence that they will not incur loss. Adopting a case by case approach is not considered adequate to achieve AEMO's objective of removing the incentive to await direction (and be automatically compensated).
	Compensation should be available to 'any category of participant [including non-scheduled generators and scheduled loads] that incurs direct costs as a result of acting in accordance with verbal instructions or requests from AEMO/AEMO control room during a period of market suspension' (p. 4). Losses due to scaling should not be compensable as this is not a direct cost (p. 4).	The final rule compensates scheduled generators and ancillary service providers whose estimated costs exceed their MSPS revenue. Non-scheduled generators, semi-scheduled generators and scheduled loads are not eligible for MSPS compensation as they are not parties to whom AEMO would typically give directions; they also have low to zero direct short run costs. However, if AEMO were to direct such parties, they would be eligible for compensation

STAKEHOLDER	ISSUE	AEMC RESPONSE
		based on the 90th percentile price under the directions compensation framework. It may be appropriate for additional categories of market participants to be included in the MSPS compensation framework as the market evolves, provided such participants meet the criteria discussed in section 4.2.2.
	Supports imposing a $5,000 threshold per market suspension event but notes this may not be necessary if APP model is adopted. This is because the administrative cost to claimants of seeking compensation would mean claims will only be pursued if the amount of compensation sought is 'quite high'. (p. 5)	Final rule does not impose a threshold per market suspension event. This is considered too blunt an approach given the event may vary in length and complexity of claims. Instead, AEMO can deduct an administrative fee from any compensation payable pursuant to an additional cost claim.
	Supports cost recovery from any customers that receive a benefit - not just those in suspended region (p. 5).	Final rule adopts the regional benefit test. This is consistent with extending eligibility for compensation to scheduled generators in neighbouring regions who incur loss due to scaling.
	Double dipping should be prevented: a participant should only receive one payment for costs that could be claimed under more than one framework but	Agreed. Final rule precludes 90th percentile compensation but enables a directed participant to claim additional costs under the (slightly wider)

STAKEHOLDER	ISSUE	AEMC RESPONSE
	different costs should still be claimable under alternative frameworks where applicable (p. 6).	additional costs provision for directions. Any additional costs paid under the MSPS framework will be net of compensation already received or expected to be received (e.g. under the APP framework).

B SUMMARY OF OTHER ISSUES RAISED IN SUBMISSIONS TO THE DRAFT DETERMINATION

This appendix sets out the issues raised in response to the draft determination and the AEMC's response to each issue. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

Table B.1: **Summary of other issues raised in submissions to the draft determination**

STAKEHOLDER	ISSUE	AEMC RESPONSE
ERM Power	ERM suggests (p. 5 of submission) that the AEMO report which is required to be published following a market suspension event (per clause 3.14.3(d)) should include information regarding the cost of engaging independent experts to assess claims for additional compensation.	It would not be appropriate to require this report to include data on the cost of independent expert reports since such data will not be available for some time (currently up to 200 business days for complex claims), whereas the report is required to be published as soon as practicable after the conclusion of the market suspension.
	ERM suggests (p. 3) that generator categories must allow for OCGTs that are duel-fuelled – capable of operating on gas or diesel – as they believe that during a system restoration event, the liquid fuel capability of OCGTs, when this is available, may be relied on heavily by AEMO if gas infrastructure has been impacted by any power system event. ERM suggests that separate categories should be created for gas and liquid fuelled OCGT plants and compensation should be paid based on actual fuel use verified by independent meter readings.	The development of generator categories in both the NTNDP and MSPS compensation framework is a matter for AEMO. At present the NTNDP inputs assume that OCGTs with dual-fuel capability run on gas, which is appropriate given the much higher cost of diesel. The Commission notes that dual-fuel plants can, and have, used both gas and diesel within a single day. While this matter can be resolved through the development of the Market Suspension Compensation Methodology, the Commission considers that creating separate categories is likely to complicate the framework without solving for all scenarios.

STAKEHOLDER	ISSUE	AEMC RESPONSE
		A simpler approach would be to allow claimants using liquid fuel to claim additional compensation based on the verified meter readings referred to in the ERM submission.
ERM Power and EnergyAustralia	Both ERM and EA proposed that the timeframe for publishing the MSPS change from 14 days to 1 day (p. 5 of ERM submission and p. 3 of EA submission).	This issue is beyond the scope of the rule change request and therefore cannot be progressed as part of the current process.
AGL	AGL notes (p.2) that during the 2016 market suspension, AEMO did not allow participants in the suspended region to be enabled for FCAS to the detriment of those participants. It recognises that this issue may be out of scope but suggests it should be further investigated if the opportunity arises in future.	As AGL notes, this issue is out of scope and therefore cannot be examined as part of the current rule change process.

C LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this final rule determination.

C.1 Final rule determination

In accordance with s. 102 of the NEL the Commission has made this final rule determination in relation to the rule proposed by AEMO.

The Commission's reasons for making this final rule determination are set out in section 3.4.

A copy of the final rule is attached to and published with this final rule determination. Its key features are described in chapter 4.

C.2 Power to make the rule

The Commission is satisfied that the final rule falls within the subject matter about which the Commission may make rules. The final rule rule falls within s. 34 of the NEL as it relates to regulating the operation of the national electricity market (s. 34(1)(a)(i)) and the activities of persons (including Registered Participants) participating in the national electricity market or involved in the operation of the national electricity system (s. 34(1)(a)(iii)). Further, the final rule falls within the matters set out in Schedule 1 to the NEL as it relates to the setting of prices for electricity and services purchased through the wholesale exchange operated and administered by AEMO (Schedule 1, item 7) and the methodology and formulae to be applied in setting prices referred to in item 7 (Schedule 1, item 8).

C.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the rule
- the rule change request
- submissions received during first and second round consultation
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[158]

The Commission may only make a rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of Australian Energy Market Operator (AEMO)'s declared network functions.[159] The final rule is compatible

158 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy. On 1 July 2011, the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.

159 Section 91(8) of the NEL.

with AEMO's declared network functions because it is unrelated to them and therefore it does not affect the performance of those functions.

C.4 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as civil penalty provisions.

The Commission's final rule includes the addition of clause 3.15.8A(c) into the NER. The Commission is recommending to the COAG Energy Council that clause 3.15.8A(c) be classified as a civil penalty provision due to the importance of the provision in the context of funding market suspension compensation, and to act as a deterrent against a failure by market customers to pay the amounts calculated in accordance with clause 3.15.8A(b).

The Commission also notes that a similar provision in clause 3.15.9(f) is currently classified as a civil penalty provision. Clause 3.15.9(f) relates to the recovery of AEMO's costs incurred in contracting for reserves, whereas clause 3.15.8A(b) relates to the recovery of market suspension compensation.

C.5 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the COAG Energy Council that new or existing provisions of the NER be classified as conduct provisions.

The final rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the COAG Energy Council that any of the proposed amendments made by the final rule be classified as conduct provisions.