Final report on compensation related to *directions* that occurred on 1 December 2016

An independent expert report prepared for AEMO

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Executive Summary

Synergies Economic Consulting (Synergies) was appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine compensation in respect of *directions* AEMO issued on 1 December 2016. This final report is published pursuant to clause 3.12.3 (c) (1) (i) of the National Electricity Rules (NER).

In accordance with the NER, Synergies issued draft determinations and a draft report on 10 April 2017. Subsequent to these draft determinations, Synergies has had discussions with the *directed participants* and has received additional information relevant to the compensation claims. These discussions and new information have been taken into account in this final report and in the final determinations.

The *directions* followed a SA separation event caused by a credible contingency on the Moorabool to Tarrone 500 kV transmission line at a time when one circuit of the Heywood Interconnection was undergoing a scheduled outage. Four *directions* were issued and subsequently cancelled on 1 December 2016, leading to the following claims for compensation.

Claim 1: FCAS *direction* in SA

At 01:15 hrs on 1 December 2016 AEMO issued a *direction* to a generator in SA to provide up to 10 MW of Fast Raise FCAS (notice 55973). The *direction* was cancelled at 05:00 hr (notice 56015). Following this *direction*, AEMO received a claim for additional compensation for the *Directed Participant* under clause 3.15.7B of the NER for the period commencing *dispatch interval* (DI) ending 00:15 through DI ending 05:00 on 1 December 2016.

Claim 2: *direction* for other services in SA

At 02:30 hrs on 1 December 2016 AEMO directed a generator in SA (notice 55981) to provide other services, to reduce output, and a second *direction* at 03:00 hrs (notice 56082) as a counter-action to this prior *direction*, both of which were cancelled at 05:00 hrs (notice 56015). These gave rise to a requirement for AEMO to compensate the *Directed Participant* under clause 3.15.7A. We characterise this as a claim for compensation for being constrained off.

Claim 3: *direction* for other services in VIC

At 10:30 hrs on 1 December 2016 AEMO issued a *direction* to a Victorian generator for other services, to shut down (notice 56046). The *direction* was cancelled at 15:45 hrs on the same day (notice 56067). This gave rise to a requirement for AEMO to compensate the *Directed Participant* under clause 3.15.7A over the period commencing DI ending 10:35 hrs through DI ending 15:45 hrs. We characterise this as a claim for compensation for being constrained off.

Claim 4: a claim for *Affected Participant* compensation

Related to the *direction* to a Victorian generator in respect of ***Claim 3***, AEMO received a claim for compensation by an *Affected Participant* in SA under clause 3.12.2 covering the same period.

Synergies has determined that, in respect of:

- ***Claim 1: FCAS direction in SA***, that the South Australian generator is entitled to compensation for loss of revenue under clause 3.15.7B. We have determined the appropriate level of compensation and informed the directed participant accordingly;
- ***Claim 2: direction for other services in SA***, that compensation under clause 3.15.7A in the nature of a fair payment price for being constrained off in these circumstances is zero;
- ***Claim 3: direction for other services in VIC***, that compensation under clause 3.15.7A in the nature of a fair payment price for being constrained off in these circumstances is zero; and
- ***Claim 4: a claim for Affected Participant compensation***, that, properly construed, compensation under clause 3.12.2 does not extend to loss of anticipated market ancillary services revenue, but does extend to loss of anticipated revenue from the energy spot market. Based on this, we have determined the appropriate level of compensation and informed the directed participant accordingly.

The total amount of compensation for these *directions* is $32,948.59 in respect of clause 3.12.2 and $125,552.29 in respect of 3.15.7B. The *Directed* and *Affected Participants* have been individually informed of these determinations, the reasons for them, and the amounts.

Finally, Synergies has identified a number of shortcomings in the compensation arrangements for *directed* and *affected participants*. AEMO and AEMC may want to consider these in any future review.

Contents

1 Introduction

Synergies Economic Consulting (Synergies) was appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine compensation in respect of four directions that AEMO issued on 1 December 2016. All of the *directions* were subsequently cancelled on 1 December 2016.

In accordance with the NER, Synergies issued draft determinations and a draft report on 10 April 2017 in relation to these *directions*. Subsequent to these draft determinations, Synergies has had discussions with the *directed participants* and has received additional information relevant to the compensation claims. These discussions and new information have been taken into account in this final report and in the final determinations.

This final report sets out the approach that Synergies has adopted to determine the compensation for *Directed Participants* and *Affected Participants* under the applicable National Electricity Rules (NER),[1] and the aggregate amount of compensation. The directed and affected parties have been separately notified of our final determination.

1.1 The separation event[2]

The *directions* followed a South Australia separation event. Prior to the separation event, two relevant scheduled outages were underway: on the Heywood No 2 500kV bus bar limiting the Heywood SA-VIC Interconnector to a single 500kV circuit; and an outage on one of the two 500kV circuits between Heywood and the Alcoa Portland Aluminium smelter (APD).

In response to these scheduled outages, AEMO implemented a series of constraints in order to maintain the system in a secure state including:

- limits on flows on the Heywood Interconnector to ensure that the rate of change of frequency (RoCoF) in SA as a result of a credible contingency did not exceed 1 Hz/s;
- limiting Mortlake generation to 0MW; and
- ensuring at least 35 MW of raise and lower frequency control ancillary services (FCAS) were available in SA.

Operational demand in SA at the time was 1,386 MW met by 865 MW of thermal generation, 85 MW of wind generation and 463 MW of import from Victoria (217 MW via Heywood and 223 MW on Murraylink).

1 This determination is based on NER v86 current from 1 December 2016 to 24 December 2016 available at http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Rules/National-Electricity-Rules-Version-86.

2 AEMO (28 February 2016) *Final Report – South Australia Separation Event, 1 December 2016.*

At 00:16 hrs the Moorabool to Tarrone 500kV transmission line tripped at both ends. The fault did not clear so the line remained open after an unsuccessful auto-reclose. This severed the Heywood interconnection to SA and left the smelter load at APD connected to the SA network. As a result, the 217 MW of flows from VIC to SA across the Heywood Interconnector were reversed to 480 MW due to smelter load drawing on the SA network. This continued for 400 ms at which time the APD pot line automatically tripped. This reduced flows from SA to VIC to zero. During this period, the SA network frequency dropped to 48.23 Hz triggering 190 MW of automatic under-frequency load shedding (UFLS) along with 40 MW of other load reductions.

Three of the directions were issued in the process of recovering from this event and were cancelled at 05:00 hrs. The fourth was issued later on 1 December 2016 while the Moorabool to Tarrone 500 kV line was still under repair.

1.2 The *directions*

1.2.1 Claim 1: FCAS *direction* in SA

At 01:15 hrs on 1 December 2016 AEMO issued a *direction* to a generator in SA to provide up to 10 MW of Fast Raise FCAS (notice 55973). The *direction* was cancelled at 05:00 hr (notice 56015). At the time of the *direction* the generating unit in question had not bid as being available to provide Fast Raise FCAS. At 07:42 hrs AEMO issued a market notice advising the market of the implementation of intervention pricing between 01:35 hrs to 05:00 hrs.

Following this *direction*, AEMO received a claim for additional compensation for the *Directed Participant* under clause 3.15.7B of the NER for the period commencing *dispatch interval* (DI) ending 00:15 through DI ending 05:00 on 1 December 2016. The claim was for a sum in excess of $100,000 so it was referred to an independent expert under clause 3.15.7B (c) (1).

1.2.2 Claim 2: *direction* for other[3] services in SA

At 02:30 hrs on 1 December 2016 AEMO directed a generator in SA (notice 55981) to provide other services and a second *direction* at 03:00 hrs (notice 56082) as a counter-action to this prior *direction*, both of which were cancelled at 05:00 hrs (notice 56015). At 07:42 hrs AEMO issued a market notice advising the market of the implementation of intervention pricing between 01:35 hrs to 05:00 hrs.

These gave rise to a requirement for AEMO to compensate the *Directed Participant* under clause 3.15.7A and, pursuant to clause 5.15.7A (b1), AEMO determined that an independent

[3] A direction for services other than energy and ancillary services (clause 3.15.7A (a1)).

expert could reasonably be expected to determine a fair payment price for the services provided.

1.2.3 Claims 3 and 4: *direction* for other services in VIC

At 10:30 hrs on 1 December 2016 AEMO issued a *direction* to a Victorian generator for other services, specifically to shut down (notice 56046). The *direction* was cancelled at 15:45 hrs on the same day (notice 56067). At 11:15 hrs AEMO issued a market notice to advise that intervention pricing would not be implemented for the duration of this *direction*.

This gave rise to a requirement for AEMO to compensate the *Directed Participant* under clause 3.15.7A over the period commencing DI ending 10:35 hrs through DI ending 15:45 hrs — ***Claim 3***. Pursuant to clause 5.15.7A (b1), AEMO determined that an independent expert could reasonably be expected to determine a fair payment price for the services provided.

AEMO also received a claim for compensation by an *Affected Participant* in SA under clause 3.12.2 over the same period — ***Claim 4*** — in excess of that determined by AEMO. The claim was for a sum in excess of $100,000 so it was referred to an independent expert under clause 3.15.7B (c) (1).

1.3 Structure of the report

In the remainder of this report, we set out the basis for our draft determinations of compensation resulting from these directions under the NER, as follows:

- section 2 sets out and applies the provisions of clause 3.17.7A as they relate to ***Claim 2*** and ***Claim 3***;
- section 3 sets out applies the provisions clause 3.17.7B as they relates to ***Claim 1***;
- section 4 sets out applies the provisions clause 3.12.2 as they relates to ***Claim 4***; and
- section 5 presents some concluding remarks.

2 Claims under clause 3.15.7A

Claim 2 for a SA generator to reduce output and ***Claim 3*** for a generator in VIC to shut down were both *directions* for services other than *energy* and *market ancillary services*. As such they give rise to a requirement for AEMO to compensate at the fair payment price for the services determined in accordance with clause 3.15.7A.

2.1 Circumstances of the *directions*

2.1.1 *Claim 2*, *direction* to a SA generator to reduce output

As a result of the separation event, AEMO was obliged to ensure that the SA system was restored to a secure state. This in turn required that sufficient FCAS Raise was available within the state to cover the largest single credible contingency, which at the time was the loss of the single generating unit with the highest operating output. The quantity of R6 FCAS required depended upon that level of output of that unit.

Insufficient R6 FCAS was available within SA at 02:30 hrs. AEMO therefore issued a *direction* to the SA generating unit with the highest level of output, instructing it to reduce its output. It issued a second *direction* at 03:00 hrs. The aim was to reduce the output of the directed unit to a level that was consistent with the secure operation of the system given the availability of R6 FCAS within the state.

AEMO has determined that the affected period for the purpose of compensation is from DI ending at 02:35 hrs on 1 December 2016 to DI ending at 05:00 hrs on 1 December 2016. Intervention pricing was implemented during this period. AEMO has indicated that the *direction* was required to maintain power system security in SA.

2.1.2 *Claim 3*, *direction* to a VIC generator to shut down

Synergies understands that at 10:00 hrs on 1 December 2016, the Victorian generator that was the subject of this *direction* submitted an offer to generate priced at -$1,000 MWh for the whole of its available capacity. As a result of this offer, the generator commenced operation on or around that time. Its operation resulted in certain system constraints becoming binding or being violated.[4] In response, at 10:30 hrs AEMO issued a *direction* for the generator to shut down in order restore the power system to a secure state. The *direction* was cancelled at 15:45 hrs on the same day.

AEMO has determined that the affected period for the purpose of compensation is from DI ending at 10:35 hrs on 1 December 2016 to DI ending at 15:45 hrs on 1 December 2016.

[4] F_S++HYSE_L5, F_S++HYSE_L6_1, F_S++HYSE_L6_2, F_S++HYSE_L60 all of which related to the provision of FCAS Lower in SA at the time.

Intervention pricing was not implemented in this period. AEMO has indicated that the *direction* was required to maintain power system security in VIC during the affected period.

2.1.3 Descriptions of the services provided

Pursuant to clause 5.15.7A (b1), AEMO determined that an independent expert could reasonably be expected to determine a fair payment price for the services provided under these *directions*. Clause 3.15.7A (c) (3) (i) requires that the independent exert sets out a description of the services provided in response to the *direction* in its final report.

The services provided under ***Claims 2*** and ***Claim 3*** are identical, namely the reduction in the *dispatch level* of *energy* despite the offer prices for the generators being lower than the relevant *regional reference price*. Both were required in order to allow for secure operation of the system, i.e. to allow the system to operate without any constraints being violated. In the case of ***Claim 3,*** the generator in question was *directed* to reduce the *dispatch level* of generation to zero.

Notwithstanding that that reductions in generation under these two claims were executed by means of AEMO *directions*, they are both examples of generators being constrained off. This term is most often used in power markets to describe circumstances where there is insufficient transmission capacity to allow the generator in question to operate at the level indicated by its offer without undermining the security of the system; whereas if the transmission constraint were not binding then the generator would operate at the level consistent with its offer. In the NER, *constrained off* is defined as:

> In respect of a *generating unit*, the state where, due to a *constraint* on a *network*, the output of that *generating unit* is limited below the level to which it would otherwise have been *dispatched* by AEMO on the basis of its *dispatch offer*.

In ***Claim 3***, for example, the directed generator submitted an offer of -$1,000/MWh which would indicate that, absent constraints, it would operate even if the spot price for energy was zero. For the duration of the *direction*, the system could not operate securely (i.e. without violating constraints) with the generator in operation even though the *regional reference price* in VIC at those times was greater than zero.

The constraints that were violated by the operation of the VIC generator in ***Claim 3*** were not strictly transmission constraints. Rather, they were insufficient supply of FCAS Lower in SA. In Synergies view they are functionally the same as transmission constraints in that they could be considered to have arisen because there was insufficient transmission capacity to enable SA's requirement for FCAS Lower to be met from regions elsewhere within the

NEM. This is consistent with the characterisation of *constraints* given in clause 3.6.4 of the NER.[5]

The question that these compensation claims raise is the fair payment price for the service of being constrained off.

2.2 Requirements of the independent expert

To address this question under clause 3.15.7A (c) (1), the independent expert is required to:

- take into account other relevant pricing methodologies in Australia and overseas, including but not limited to:
  - other electricity markets;
  - other markets in which the relevant service may be utilised; and
  - relevant contractual arrangements which specify a price for the relevant service; and
- disregard the disinclination of the provider to provide the services and the urgency with which the services were needed;
- treat the *Directed Participant* as willing to supply at the market price that would be expected to prevail for the service under similar supply and demand conditions; and
- deem the fair payment price to be that which would prevail in a market for the service under similar supply and demand conditions.

Synergies confirms that for the purposes of this draft determination we have disregarded any disinclination by the *Directed Participant* to provide the service. We have treated the *Directed Participant* as willing to supply at the market price that would be expected to prevail for the service under similar supply and demand conditions.

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5 One of the directed participants questioned in correspondence whether the reference to clause 3.6.4 is apposite in respect of ***Claim 2*** given that the SA region was islanded at the time. The refence to clause 3.6.4 is not central to this final determination. Nevertheless, in the language of clause 3.6.4 (a), SA being islanded is equivalent to saying that, for operational reasons, it is not acceptable for the Heywood interconnector to transfer more than 0 MW of electricity (or the equivalent ancillary service) in either direction. That constraint (brought about as a result of scheduled and non-scheduled outages) therefore prevented SA from meeting its R6 FCAS requirements from elsewhere, necessitating the *direction*. In the NER, there is no express distinction between a constraint of 0 MW and a constraint set at some other level above zero.

The participant also noted that the proximate cause of the *direction* related to FCAS whereas clause 3.6.4 related to 'network transfers'. Synergies understands that the participant uses the term 'network transfers' to mean energy transfers; clause 3.6.4 uses the undefined term 'electricity transfers'. In Synergies view, the term 'electricity transfers' can encompass both energy and ancillary services, and if clause 3.6.4 was meant to be confined to energy transfers, it would have used the defined term *energy*. Clause 3.6.4 also refers to *dispatch*, which encompasses *energy* and *market ancillary services*.

The participant also 'questions the relevance or rules for normal operation of the NEM to consideration of implications of direction.' Synergies does not consider that clause 3.6.4 is confined to what might be described as 'normal operation' since constraints (as defined in this clause and as defined in clause 10) can arise under normal and abnormal circumstances.

2.3 Pricing methodologies in Australia and overseas

2.3.1 Pricing in Australia

The NEM determines energy spot prices on the basis of a generation schedule created using a centralised national dispatch process that takes account of transmission constraints. The principles applicable to spot price determination are set out in clause 3.9.1. Clause 3.9.1 (a) (3) states that:

> *dispatch prices* determine *dispatch* such that a *generating unit* or *load* whose *dispatch bid* or *dispatch offer* at a location is below the *spot price* at that location will normally be *dispatched*

Clause 3.9.1 (a) (4) states that:

> *network losses*, *network constraints*, the availability of *scheduled network services* and network *dispatch offers* are taken into account in the determination of *dispatch* and consequently affect *dispatch prices*, *spot prices* and (apart from *network losses*) *ancillary services prices*

And clause 3.9.1 (a) (6) states that

> when the *spot price* is determined, it applies to both sales and purchases of electricity at a particular location and time.

Although elaborated upon in other provisions of the NER, these indicate that the NEM does not normally compensate generators that are affected by constraints for any additional revenue or profit that they would have earned had the constraints not applied.

The question of whether this should be the case was reviewed most recently by the AEMC in 2015 in its review of optional firm access (OFA),[6] and has been reviewed many times since the NEM commenced operation. It was also considered at length at the time of the original market design.[7] In 2015, the AEMC concluded that 'current market conditions do not justify [OFA] implementation.'[8]

Somewhat oddly, clause 5.4A (h) (1) of the NER appears to contemplate compensation to generators when they are constrained off. But as the AEMC also notes:[9]

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6 The AEMC stated that, under an OFA scheme, generators unable to operate at their offered capacity due to network constraints would be able to purchase contracts that would compensate them for the resultant losses. These would result in the financial equivalent of firm access rights.

7 It is beyond the scope of this determination to review why this design decision was made at the outset.

8 AEMC (9 July 2015) *Optional Firm Access, Design and Testing Final Report Volume 1* vii.

9 Ibid 37.

> This clause of the Rules appears to contemplate generators negotiating firm transmission network user access with TNSPs.[10] The Rules provide for generators to negotiate compensation from a TNSP in the event that they are constrained off or on the network, in return for an access charge. However, this provision cannot work in practice because the scheme is not mandatory and all generators have open access to the network.

Accordingly, we conclude that the NEM does not compensate generators that are constrained off, and that there is no clear exception to this principle when the instruction to reduce output or shut down results from a *direction* rather than in the process of implementing *central dispatch*.

2.3.2 Other electricity markets

The approach to payments to constrained off generators adopted by the NEM is by no means the only approach. Different paradigms operate in some overseas electricity markets.

The UK

The electricity market that operates in the mainland UK under the administration of National Grid does compensate constrained off generators.

National Grid operates a balancing mechanism[11] to instantaneously match supply and demand.[12] Generators and large demand side participants can submit offers to be constrained on or bids to be constrained off. National Grid selects balancing bids so as to minimise the costs of balancing. A generator that is constrained off through the balancing mechanism pays their offer price to the balancing mechanism but retains the revenue from their power trading in related markets. On the presumption that the constrained off offer reflects the cost savings it would achieve as a result of reducing its output (predominantly fuel costs), the net effect is that the generator in question is compensated for the foregone profits resulting from being constrained off.

In prior versions of the England and Wales electricity market, before the New Electricity Trading Arrangements (NETA) were adopted in 2001, constrained off generators were paid at the unconstrained spot price less their offer price.[13] This also compensated generators for the foregone profits of being constrained off.

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10 Transmission network service providers.

11 See http://www2.nationalgrid.com/uk/services/balancing-services/

12 Through the balancing and settlement company, Elexon.

13 There was also a marked change in congestion management in 2005 when the Scotland market was amalgamated with the England and Wales market.

Ontario

Ontario operates a system of Congestion Management Settlement Credits similar to the system that operated in England and Wales prior to NETA.[14] The Ontario Independent Electricity System Operator (IESO) determines a market schedule and market prices based on bids and offers that does not take account of losses or transmission constraints within the province.[15] It is determined after the fact so makes use of actual demand.

This market schedule forms the basis for settlements, but adjustments are made for generators that are constrained on[16] or constrained off as a result of losses and transmission constraints within the province. Constrained on generators are paid their offer price when it is above the market price. Constrained off generators are paid the market price minus their offer price (i.e. foregone profit) when the market price is above their offer price.

The IESO does have additional powers when the market enters Emergency or High-Risk conditions, and is empowered to take additional action[17] and to recover any costs incurred.[18] Compensation arrangements are left to the IESO,[19] but the broad thrust of arrangements in Ontario for unscheduled events (other than constrained off and constrained on operation as set out above) is to compensate the affected party for any costs incurred.[20]

Finally, it should be noted that the IESO takes a much more proactive role in ensuring system security and reliability than does AEMO in Australia, reducing the role of *directions* and compensation thereof. To be clear, this statement reflects the differences in the relevant market rules and the differing operational philosophies underpinning the respective markets, rather than the conduct of a market operator. For example, Chapter 7 section 9.1.1 of Ontario's market rules sets out that:

> The *IESO* shall procure, primarily through contracts, certain *physical services* that are needed to maintain *reliable* system operations but that are not offered in the *real-time markets*. The *IESO* may also enter into contracts allowing it to direct the operations of specific *generation facilities* or *load facilities* that are critical to system *reliability* under certain conditions. This section 9 describes such *physical services* and the manner in which the *IESO* shall procure them.

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14 http://www.iemo.com/Pages/Participate/Settlements/Guide-to-Electricity-Charges.aspx

15 It also uses assumed rather than actual ramp rates.

16 A generator is constrained on if it is dispatched above the level that is indicated by its offer price in the market schedule. In markets like Ontario, the market price will be less than the offer price for such generators.

17 As set out in sections 2.3 and 2.4 of Chapter 5 of the *Market Rules for the Ontario Energy Market* available at http://www.ieso.ca/Sector%20Participants/Market%20Operations/Market%20Rules%20And%20Manuals%20Library.

18 Ibid Chapter 9, section 4.8.

19 Ibid Chapter 7, section 7.7.4.

20 See, for example, ibid Chapter 7, section 6.3B.

This proactive approach of independent system operators actively procuring the necessary services to maintain secure and reliable operation is widespread in North America and contrasts with the greater reliance on short-term markets and *direction* adopted in the NEM. In effect, this procurement model results in compensation to generators that provide these services through contract payments agreed in advance rather than *ad hoc* and *ex post* compensation when the services, unavailable from the short-term markets, are obtained through *directions*. Given the rapidly changing challenges presented in efficiently operating the NEM, it may be appropriate to reconsider the Rules to enable a more proactive approach to be adopted by AEMO (or, in some cases, TNSPs) in procuring relevant services.

Other markets that compensate constrained off generation

There are a number of other markets including France, Italy, Germany and Spain which provide some compensation for generators that are constrained off. The details differ across markets. For example, Italy defines market zones and compensates generators that are constrained off due to intra-zonal constraints, but not due to constraints between zones.[21]

Markets based on locational marginal price

A number of competitive electricity markets in the US are based on a pricing framework known as locational marginal pricing (LMP). These include PJM (Pennsylvania, New Jersey and Maryland) , ERCOT (Texas), New York, MISO (Mid-West) and New England.[22]

In markets based in LMP, prices are determined for each node[23] on the transmission system using a security constrained economic dispatch based on bids and offers. Where this differs from markets such as the NEM and Ontario is that a different price is determined for each node, and that price will be affected by transmission and other security-related constraints and marginal losses. For example, the prices at each end of a constrained transmission line will differ, being lowest at the node where there is a net injection of power.

In essence, LMP sets a clearing price at each node. As such, there is no real concept of constrained off. Rather, the nodal price at a connection node for a generator that cannot generate at its full capacity due to inadequate transmission capacity will fall relative to the nodal price in the absence of the constraint. In principle, it will fall to the level at which the generator is just willing to supply an amount that is consistent with the security-constrained

21 For a useful overview of payments for constrained off generation in these markets see Zwolle (24 June 2009) *A System for congestion management in the Netherlands* available at https://www.eumonitor.nl/9353000/1/j4nvgs5kjg27kof_j9vvik7m1c3gyxp/via97p8d12yl/f=/blg21891.pdf.

22 For a comprehensive discussion of LMP see http://lmpmarketdesign.com/index.php.

23 Essentially each point of interconnection with generation, load or dispatchable transmission, and at each substation on the network.

operation of the system[24] (or at a level that will attract additional demand that can make use of the generation that otherwise cannot operate due to transmission limitations).

It follows that there is no formal compensation for constrained off generation. Financial transmission rights (FTRs) may be available in LMP markets that entitle owners of the rights to the difference in spot prices at different nodes on the system, which can help market participants manage transmission constraint risks.[25]

New Zealand

New Zealand, which operates a variant of LMP, similarly does not compensate generators when they are constrained off. Clause 13.201 (1) of the Electricity Industry Participation Code 2010[26] (the NZ Code) states that:

> A **generator** is not entitled to be paid compensation in respect of any constrained off situation except as provided for in an **ancillary service arrangement** entered into by the **system operator** and the **generator** (emphasis in the original identifying defined terms)

The NZ Code requires that considerable information is published concerning constraints including **constrained off amounts** which are calculated as the difference between the constrained off generator's offer price and the final spot price, all multiplied by the reduction in generation in MWh resulting from being constrained off.

It is also notable that the definition of constrained off situations in the New Zealand Code (clause 13.192) makes no reference to the cause or circumstances of the constraint. It refers only to situations where a generator is not dispatched at its expected level given its offer price and the final price at the injection point.

2.3.3 Discussion of other markets

The foregoing demonstrates two broad approaches to compensation for generators that are constrained off: compensation based on foregone profits; and no compensation. Australia falls into the latter group. This issue has been contested by respected experts since power market deregulation commenced in the 1980s and different markets have taken different directions.

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[24] In reality, LMP is rarely as tidy as this description suggests, and there is some flexibility in how nodal prices are calculated. For example, generators supplying ancillary services can sometimes be removed from the merit order by the market operator. And some market operators are empowered to enter into contracts with certain generators that are pivotal to system operation, and this can affect the LMP calculations.

[25] It would not be correct to view FTRs as a mechanism for compensating constrained off generation since in a risk neutral world the cost of an FTR to a generator that expects to be constrained off in some future periods would be equal to the expected revenue under the FTR. That is, the value of the FTR is zero.

[26] Available at https://www.ea.govt.nz/code-and-compliance/the-code/.

Markets that do compensate constrained off generation have run into difficulties at times, for example, from concerns over gaming when constraints arise and by the difficulties that market participants can face trying to manage the risks associated with volatile and uncertain compensation costs. Markets that do not compensate constrained off generators may have weak incentives to make timely transmission investments needed to minimise constraints, and these can become quite acute at times of technological change such as the rapid rise of wind-based generation. They can also experience gaming difficulties when generators are constrained on. But neither approach is clearly better; often the topology of the system and the state of the network at the inception of the market can influence the advantages and disadvantages of the different approaches.

Compensating markets often rely upon locational transmission use of system (TUOS) charges to signal the impact of investment choices on constraints and on the costs of their alleviation. This reduces the likelihood that constraints will be exacerbated by future investment choices by market participants. TNSPs in these markets are usually given incentives to minimise compensation payments. The UK adopts both of these mechanisms. A more intrusive approach to controlling compensation payments is to prevent new generators from connecting when there is insufficient available transmission. This approach is adopted in France and was in the past adopted in the UK.

One of the *directed participants* suggested that we focus on compensation under abnormal rather than normal operation. This is not straightforward. Ontario, for example, has specific arrangements for dealing with emergencies and allows the ISO to compensate generators in such emergencies, but it does not specify the amount or framework for that compensation. Some markets avoid the issue by allowing the ISO to procure the services it needs to secure the system, so compensation is a matter of mutually agreed contract terms between the ISO and the generator; abnormal operation, as such, is also less likely to arise. Other markets don't have a clear equivalent of intervention events, as defined under the NER, or related compensation arrangements. Finally, we note that clause 3.15.7A (c) (1) directs that the urgency of the supply requirement should be disregarded; this suggests that compensation mechanisms in other markets specifically targeting urgent or emergency conditions are not necessarily an appropriate benchmark.

There are no doubt changes to the NEM rules that would reduce transmission constraints, improve transmission investment and increase resilience in the face of rapid technological change. But analysis of overseas electricity markets, some of which pay compensation to generators that are constrained off, does not currently present a case for compensating generators in Australia that are constrained off as a result of *directions*. In our view, there are four main reasons for this:

- there is ample evidence that electricity markets can and do operate well without paying compensation to generators that are constrained off;

- Australia has adopted a system based generally on not compensating constrained off generation, and there is no compelling evidence that the alternative would be superior at this time;
- where compensation is paid, it is important that other measures are in place to minimise the extent of the compensation, not all of which are currently in place in Australia; and
- we would be concerned that paying compensation for generation that is constrained off due to a *direction* could widen the scope for generator gaming in ways that are difficult to predict.

2.4 Urgency of the supply requirement

Synergies confirms that is has not considered the urgency with which the services were needed. In Synergies view, this is an important criterion within the NER as it allows the independent expert to consider compensation arrangements where there is no urgency and where *direction* may not be the means of securing the service in question.

2.5 Other markets in which the relevant services may be utilised

There are no other markets in which the service of a generator reducing its *dispatch level* of *energy* could be utilized.

2.6 Relevant contractual arrangements

Synergies is not aware of any contractual arrangements in Australia that set out the price that a generator should be paid for reducing its output or shutting down.

2.7 Response to observations from a *directed participant*

One of the *directed participants* asked Synergies to reconsider whether the directed services in ***Claim*** 2 and ***Claim*** 3 are identical. At a trivial level they are, in so far as both directions required generators to reduce their generation to levels below which they would choose to operate based solely on their offer prices. However, the participant points to differences in circumstances, namely that:

- the ***Claim 3*** direction occurred once the network had been restored to the condition before the contingency. That is, the generator was directed even though the Heywood interconnector had been reenergized. Whereas ***Claim 2*** was directed at managing the islanded system; and

- the ***Claim 3*** generator was subject to a constraint prior to the contingency and only subsequently to a *direction*; the participant was not clear why AEMO used different mechanisms to restrict its dispatch level.

2.7.1 The use of *directions* to reduce generator dispatch levels

Synergies discussed with AEMO the use of *directions* as opposed to normal dispatch instructions. Synergies understands that, where a reduction in output is required in order to meet an ancillary services constraint such as a lack of R6 or L6 FCAS in a region, AEMO's standard operating procedures specify the use of *directions*.

Claim 2 was a *direction* to reduce generation to a level that was commensurate with the quantity of R6 FCAS that was available within the islanded SA system (i.e. to satisfy an R6 FCAS constraint in the NEMDE).[27]

Claim 3 was a *direction* to reduce generation to a level that was commensurate with the quantity of FCAS Lower that was available in the non-islanded SA region at the time (i.e. to satisfy F_S++HYSE_L5, F_S++HYSE_L6_1, F_S++HYSE_L6_2, F_S++HYSE_L60 constraints in the NEMDE), although arguably the underlying circumstances leading to the *direction* was the need to reduce the loading on the Heywood interconnector which had reached 500 MW (well above the limit of 250 MW).

On this basis, ***Claim 2*** and ***Claim 3*** are similar in the sense that they are *directions* to prevent the violation of binding constraints.[28]

Synergies has not reviewed whether the use of *directions* to meet ancillary services constraints that cannot be managed through available *market ancillary services* is always appropriate. Synergies notes that if *directions* are not operationally necessary[29] when reducing the energy dispatch level of a generator to ensure that an ancillary services constraint is met, it may be sensible to adapt current operating procedures.

2.7.2 Normal and abnormal system operation

The same *directed participant* questioned whether compensation payments that are appropriate for normal system operation, such as the zero compensation for generators that are required to reduce generation, are so when the system cannot be said to be operating normally.

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27 National Electricity Market Dispatch Engine.

28 Which constraints were , in turn, a consequence of transmission constraints.

29 For example, *direction* may be essential to ensure timely compliance without which secure and reliable operation cannot be maintained.

This is not straight forward, not least because the concepts of normal and abnormal operation are not clearly defined. For example, in so far as *directions* are synonymous with abnormal operations, Synergies notes that not all *directions* result in AEMO implementing intervention pricing (in which market prices are based on simulated outcomes but for the direction). This would perhaps suggest that the presence or absence of intervention pricing rather than *direction*, *per se*, should be used to determine normal and abnormal operation.

Notwithstanding, even if there was a clear distinction between normal and abnormal operation, in the absence of compelling reasons or express requirements otherwise, Synergies is reluctant to interpret compensation provisions in the NER inconsistently with broader principles within the NEM. For instance, the NEM does not guarantee generators rights of access to transmission (i.e. to generate at levels the generator itself dictates or otherwise to receive compensation) and, notably, does not levy transmission use of system charges upon them. In the absence of a clear indication in the NER, Synergies does not see the mechanism by which access is restricted, *direction* or normal dispatch, as a basis for an exception.

Even when intervention pricing does occur, the NEM is designed as far as possible to continue to allow market mechanisms to operate even when the system is under some stress, which suggests that core design principles of the NEM, such as not compensating generators that cannot operate due to constraints, should continue to operate.

Finally, Synergies is directed not to consider the urgency with which the directed services were required. This suggests that the distinction between *directed* reductions in output, which typically occur with a degree of urgency, and scheduled reductions in output, which do not, should be given a low weight at least as regards compensation claims under clause 13.15.7A.

2.7.3 Normal constrained-off operation

The participant noted that when generators are constrained off in 'normal' operation, regional reference prices are typically elevated above the level that would have been the case absent the constraint. This rise in regional reference price provides at least some compensation for being constrained off. Synergies concurs (although the effect is typically modest), and notes that no similar effect arises under a clause 3.15.7A interpretation in which there is no specific compensation for constrained off generation by *direction*.[30] The only additional compensation that is then available arises under clause 3.15.7B.

[30] If intervention pricing applies.

That said, the adverse consequences of specific compensation should also be considered in assessing compensation. The ***Claim 2*** direction was necessitated by a lack of available R6 FCAS capacity in SA at a time when high levels of R6 FCAS were predictable.[31] In Synergies view, compensating generators that are directed to reduce output so as to reduce the R6 FCAS requirement does not help to increase the supply of R6 FCAS.

A better outcome would be to ensure that markets provide effective price signals that encourage generators to increase the supply of the necessary ancillary services. Unfortunately, market price caps across ancillary services that operate inconsistently with energy market prices frustrate this. The better longer-term solution to the R6 FCAS constraint is to ensure integrity across energy and ancillary services markets that are, to a significant degree, substitutes for generators.

2.7.4 Summary

Synergies does not disregard the concerns of the *directed participant* under ***Claim 2*** and accepts that the *direction* to reduce output may have had a significant commercial impact. However, we do not consider that these concerns are sufficient to carve out an exception, that constrained off generators by *direction* should be compensated for their lost output, given the overall design framework of the NEM and the criteria that we are required to take into account under clause 3.15.7A. Nor do we consider that the differences in circumstances between ***Claim 2*** and ***Claim 3*** are a sufficient basis for an exception.

We would urge AEMO and AEMC to take account of these concerns in any future consideration of compensation for *directions* under the NER, particularly if AEMO has to make greater use of *directions* in the future to ensure secure and reliable operation. AEMO may also want to consider these concerns in any review of its operating procedures for reducing generation levels to satisfy ancillary services constraints (it is possible, for example, in some circumstances, that AEMO could consider constraining off a generator rather issuing a *direction*).

2.8 Conclusion

For the reasons set out above, we have determined that under clause 3.15.7A the fair payment price for the service of reducing or ceasing generation in response to a *direction* is zero. It is clear from the foregoing that the price that that would prevail for this service under similar but non-urgent supply and demand conditions in some markets, including the NEM itself, would also be zero, and that these markets are appropriate analogues for the NEM.

[31] Because of the scheduled outage of one Heywood circuit

We are mindful that generators can incur costs as a result of reducing output or, particularly, shutting down.[32] Most markets provide a mechanism whereby generators that are compelled to change their operations can recover the costs of so doing if market revenues are insufficient. The NER makes provision for this under clause 3.15.7B in the event that compensation under clause 3.15.7A does not cover the additional net direct costs of providing the services.

32 For example, maintenance costs are related to the number of starts and stops, particularly for peaking plant.

3 Claim under clause 3.15.7B

The claimant in ***Claim 1*** was a *Directed Participant* and was instructed to provide up to 10 MW of Fast Raise FCAS between 00:15 hrs and 5:00 hrs on 1 December 2016. As such, they are entitled to compensation under clause 3.15.7, which sets out compensation based upon:

- the amount of the relevant *market ancillary service* which the *Directed Participant* has been enabled to provide in response to the *direction*; and
- the 90th percentile price of the relevant *market ancillary service* over the preceding 12 months.

A *Directed Participant* that is entitled to compensation under clause 3.15.7 may make a claim for additional compensation under clause 3.15.7B, which confines compensation to (clause 3.15.7B (a)):

(1) the aggregate of the loss of revenue and additional net direct costs incurred by the *Directed Participant* in respect of a *scheduled generating unit*, *semi-scheduled generating unit* or *scheduled network services*, as the case may be, as a result of the provision of the service under *direction*; less

(2) the amount notified to that *Directed Participant* pursuant to clause 3.15.7(c) or clause 3.15.7A(f); less

(3) the aggregate amount the *Directed Participant* is entitled to receive in accordance with clause 3.15.6(c) for the provision of a service rendered as a result of the *direction*.

In broad terms, clause 3.15.7B (a) entitles a *Directed Participant* to compensation to cover loss of revenue and net direct costs minus *trading amounts* for *energy* and *market ancillary services* and minus any compensation for directed services that has been determined.

The *Directed Participant* has not made a claim for compensation for additional net direct costs pursuant to clause 3.15.7B (a) (1), so this is not considered further. It has made a claim for loss of revenue.

3.1 Circumstances of the *direction*

Prior to the direction to provide up to 10 MW of Fast Raise FCAS (notice 55973), the generator that is the subject of the claim chose not to offer FCAS Raise into the relevant ancillary services market. It rebid FCAS Raise as unavailable at 01:05 hrs on 1 December 2016. The whole of its generation capacity was therefore available to the energy market. All of this capacity was bid into this market at the -$1,000/MWh price band in the expectation that all of its capacity would be dispatched into the energy market. Hence, at the time of the separation event, the generator was not available to provide FCAS Raise. The generator was therefore not available to be constrained down so as to ensure that the 6 second constraint in SA was not violated.

AEMO issued a *direction* to the generator at 01:15 hrs to provide the FCAS Raise. This was needed to maintain system security. As a result of the *direction*, the generator was constrained down to a level of dispatch in the energy market consistent with being able to supply the FCAS service.

The claimant asserts that, as a result of the *direction*, its generator sold less energy into the energy market than would have been the case had the *direction* not been in place, resulting in a loss of revenue, and that the additional revenue from the provision of the directed FCAS was less than the loss of energy market revenue.

AEMO has determined that the affected period for the purpose of compensation is from DI ending at 01:15 hrs on 1 December 2016 to DI ending at 05:00 hrs on 1 December 2016. Intervention pricing was not implemented in this period.

3.2 Meaning of 'loss of revenue' in clause 3.15.7B (a) (i)

The term 'loss of revenue' is not a defined term in the NER, nor is there any elaboration on its meaning within the clauses relating to compensation for services from *Directed Participants*. Nor is it a term if art in economics or related fields. Nor is Synergies aware of any prior independent determinations of clause 3.15.7B compensation that have addressed its meaning. Hence, the plain meaning of the term should be used.

The plain meaning of the term 'revenue'[33] in this context is usually given by 'income'[34] in the sense of periodic receipts of money by a business for the provision of a service, as might typically be determined as the product of the price of the service and the volume of service provided. In the NEM this is usually the sum of *trading amounts* due to a participant. The term 'revenue' is not qualified in any way by terms such as 'net' so should be interpreted to mean all income from a service without any deductions such as for the costs of provision.

Support for this meaning can be derived from the use of the term in the NER where it is commonly found as a component of defined terms such as *annual revenue requirement*. In this usage, it refers to the total amount of money a distribution business requires in each year to provide its services, which is almost exclusively derives from payments for the provision of

[33] Oxford English Dictionary (OED). Revenue is defined as 'an individual source or item of (private or public) income; (also) the amount of income deriving from this.'

[34] OED. Income is defined as 'that which comes in as the periodical produce of one's work, business, lands, or investments (considered in reference to its amount, and commonly expressed in terms of money); annual or periodical receipts accruing to a person or corporation; revenue.'

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services.[35] It is also used as a qualifier in distinction to costs such as '…the increase in costs in the provision of… (as opposed to the revenue impact of that event)…'[36] The term appears to be qualified when it does not refer to total income, for example by 'net' in clause 3.8.6A (g) where it refers to the difference between two total amounts.

The plain meaning of loss is disadvantage from being deprived of something or a change in conditions.[37] We therefore interpret the term 'loss of revenue' to mean the failure to get some or all of the revenue that that the *Directed Participant* would have been able to secure had it not been directed to provide a service.

3.3 What revenue sources should be considered

There is nothing within clause 3.15.7B that indicates that loss of revenue relates solely to revenue for the directed service. Rather, it uses the term 'as a result of the provision of the service' indicating that revenue that could have been earned from any services that the generator is precluded from providing as a result of the *direction* can be considered in a claim for additional compensation.

In Synergies' view, in so far as the *direction* to provide FCAS in ***Claim 1*** precluded the *Directed Participant* from providing energy, the loss of revenue from the foregone provision of energy can be considered in a claim for additional compensation.

3.4 Estimating loss of revenue

While clause 3.15.7B appears to allow compensation for loss of revenue from reduced provision of energy resulting from the provision of the directed service, it does not set out how the amount of compensation should be empirically determined.

3.4.1 Applicant's approach

The approach adopted by the claimant is based on the assumption that, absent the *direction*, it would have been dispatched into the energy market at its full capacity, and that the prices that would have prevailed in the energy market under those circumstances would have been the same as those that actually prevailed. That is, they assumed that the total expected

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35 There may also be other revenue sources such as interest on current assets (such as cash at bank), but they are typically small in comparison with payments for services.

36 Contained in the definition of *eligible pass through event* in the NER.

37 OED. Loss is defined as 'diminution of one's possessions or advantages; detriment or disadvantage involved in being deprived of something, or resulting from a change of conditions; an instance of this.' Where 'loss' is used within NER defined terms, it typically refers to power losses in transmission or distribution in terms such as *average loss factor*.

revenue was equal to the product of their total offered capacity and the energy spot price that actually prevailed.[38]

To estimate the loss, they calculated the anticipated additional settlement revenue earned from the energy market had they not been directed (as the product of dispatched generation and the prevailing energy market price) and then deducted settlement revenue from Fast Raise FCAS.

3.5 Discussion

3.5.1 Characterisation of a counterfactual

Loss must be assessed by reference to a counterfactual. The approach set out by the claimant essentially compares actual settlement revenues with the hypothetical settlement revenues assuming it had not been directed. In so far as these hypothetical revenues are above actual settlement revenues and the hypothetical properly represents the market had the *direction* not been made, then it is reasonable to characterise the difference between them as a loss of revenue for the purposes of clause 3.15.7B (a) (1).

The difficulty that would normally arise in these circumstances is the characterisation of the hypothetical and, in particular, the assumption that the prices in the hypothetical are the same as those that actually arose and that the directed generator would be dispatched in the hypothetical at its full offered capacity.

3.5.2 Hypothetical prices

In this instance, AEMO declared that all of the relevant time periods were *intervention price dispatch intervals* and that intervention prices would apply. Under clause 3.9.3 (b) AEMO must:

> …set the *dispatch price* and *ancillary service prices* for an *intervention price dispatch interval* at the value which AEMO, in its reasonable opinion, considers would have applied as the *dispatch price* and *ancillary service price* for that *dispatch interval* in the relevant region had the *AEMO intervention event* not occurred.

As a practical matter, AEMO conducts a second run of system software, but without the *direction*, in order to estimate these prices.[39] Hence, the assumption that *dispatch prices* and

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38 With appropriate adjustments for transmission loss factors.

39 In the periods in question, 01:35 hrs and 05:00 hrs, intervention pricing prevailed. Settlements for other than directed services were based on actual quantities supplied whereas prices were based on estimates of the prices that would have applied absent the intervention.

ancillary services prices in the hypothetical are the same as the prices that actually prevailed is reasonable in this instance.

As a result, the loss of revenue equates to the product of the reduction in generation in MWh as a result of the *direction* and the actual *dispatch price*. If intervention pricing was not in operation, this assumption might not be reasonable, but the circumstances of ***Claim 1*** mean that this does not need to be resolved in this determination.

3.5.3 Hypothetical quantities

Given that the whole of the capacity of the directed generator was bid into the energy market in the -$1,000/MWh band, it is reasonable to assume that, absent the *direction*, it would have been dispatched into the energy market at its full capacity. That is certainly the expectation in the absence of constraints and limiting demand.

In support of this, the *directed participant* presented evidence that various other generating units in SA that also offered their capacity into the energy market but did not provide FCAS were dispatched at the volumes they offered at -$1,000/MWh.

3.5.4 Concerns with the counterfactual prices and revenues

Any hypothetical that is based on the assumption that the *direction* had not taken place is troubling in so far as it necessarily represents a system that is not operating in a secure state,[40] or must assume that some binding constraints are no longer binding, or must assume that the directed services are supplied by some other party.

If, in reality, the *direction* was not made, the islanded SA system would be operating in an insecure state giving rise to a high likelihood of a system failure (including a possible system collapse) that could well necessitate the shutdown of the directed generator.[41] An event of this type would undoubtedly have a revenue impact. It is also possible that with the directed generator dispatched at full capacity into an insecure system, that energy prices would be depressed. These are complex matters to resolve.

Noting these difficulties, the NER accepts to a degree the artificiality of such a hypothetical in its approach to determining intervention prices under clause 3.9.3. For that reason, we apply a similar approach to the assessment of lost revenues.

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40 In so far as the direction was needed to maintain system security.

41 Or some other direction would need to be issued, which clearly does not resolve the difficulty.

3.5.5 Estimating counterfactual quantities

Rather than accepting the counterfactual given by the *directed participant*, that the generator would have operated at its offered capacity, Synergies asked AEMO to determine the level of generation that would be expected but for the *direction* using the NEMDE.

The energy generation in this 'but for' simulation was lower than the level of offered capacity, even though the *direction* to supply R6 FCAS was removed. This was not the outcome that Synergies had initially anticipated.

Discussions with AEMO confirmed that the lower than expected level of energy generation was a result of the way in which the NEMDE manages FCAS R6/R60 provision. In the absence of the direction, there was insufficient offered R6/R60 FCAS. NEMDE manages such insufficiencies by reducing *the requirement for* R6/R60 FCAS, to the extent that it can given other constraints, by lowering the dispatch level of the largest units in operation at the time in the relevant region. This reduces the maximum size of any credible contingency that has to be accommodated, thereby reducing R6/R60 requirements.

This optimisation resulted in the 'but for' level of generation being considerably lower than the offered capacity and, it transpires, only modestly higher than the actual level of generation.

3.5.6 Determination

Based on the foregoing, Synergies considers that the application for additional compensation under clause 3.15.7B in respect of ***Claim 1*** is appropriate and that the approach used by the claimant to estimate the amount is consistent with the requirements of the clause. However, the claimants estimation of the generation level but for the *direction* was excessive. Synergies used AEMO's determination of the 'but for' generation levels in this final determination.

Clause 3.15.7B requires that the amount of compensation is equal to the loss of revenue, less the amount of compensation under 3.15.7 (c) for directed *energy* or *market ancillary services*, less the *trading amount* for *spot market transactions* under 3.15.6 (c). That is, additional compensation is only made if the aggregate amount of compensation is greater than settlement revenues for directed *energy* or *market ancillary services* and *trading amounts* from market activities (i.e. *energy* and *market ancillary services* that are supplied but not under direction).

It is important to note that the deduction related to *trading amounts* from market activities relates only to *trading amounts* that accrued to the capacity that was dedicated to providing the *directed* services. In this instance, in order to provide the *directed* services, the generator in question had to back down below the level at which it had expected to operate. This backed down amount was the capacity that was used to provide the R6 FCAS; it is only the *trading amounts* earned by this capacity that are to be deducted from the lost revenue to determine compensation.

Under 3.15.7B (a4) no compensation is payable for a single *intervention price trading interval* where the resultant amount is less than or equal to $5,000.

3.6 Conclusion

For the reasons set out above, we have determined that the claim for additional compensation under clause 3.15.7B in respect of ***Claim 1*** for Raise FCAS in SA should be allowed.

In reaching this determination, we are concerned about the difficulty of estimating loss of revenue under clause 3.15.7B because of the need to establish a counterfactual against which to assess revenue loss.

Clause 3.15.7B provides a detailed but not exhaustive set of factors that can be considered in determining additional net direct costs, but is silent on the issue of loss of revenue. The task of determining loss of revenue under this clause would be made easier if it were to give qualitatively similar guidance.

Finally, we note that complexities arise in the NEM when caps on settlement prices for substitute services (in this case, R6 FCAS and energy) apply differently such that suppliers have strong incentives to prefer making offers in uncapped markets in preference to those in which caps are in operation. At times this is likely to result in shortages of supply of the capped services, perhaps necessitating greater reliance on AEMO intervention and compensation arrangements to secure the system than would otherwise be the case.

4 Claim under clause 3.12.2

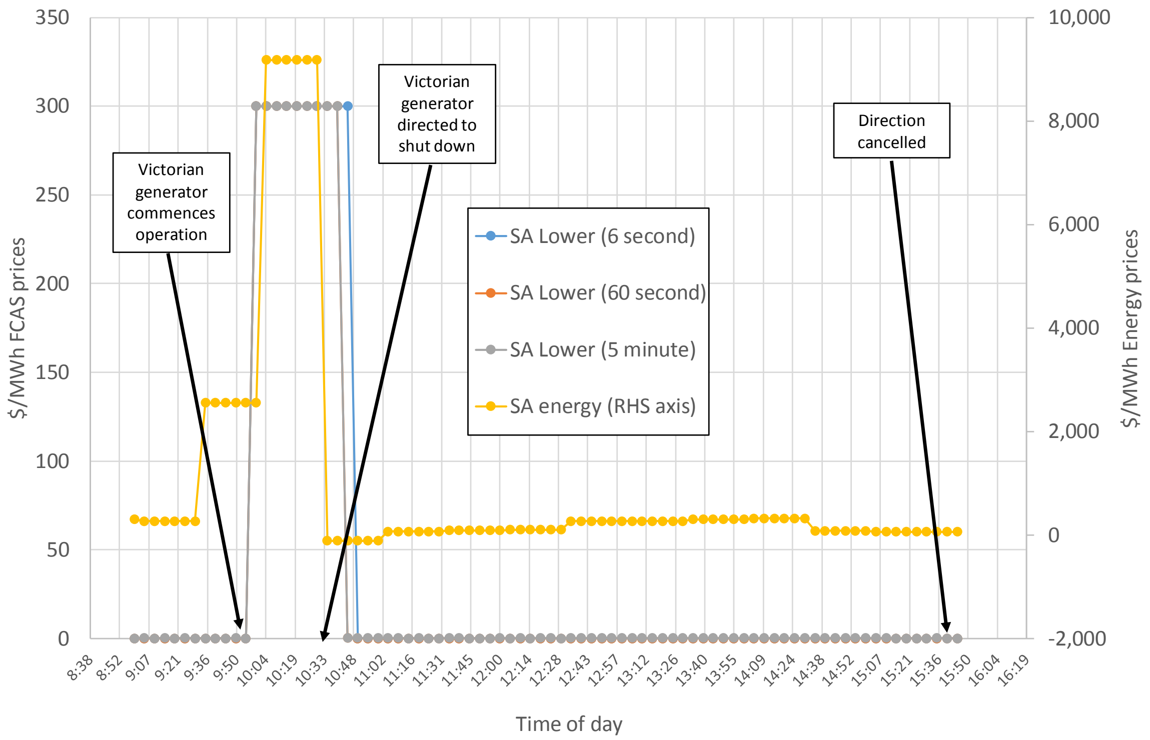
Clause 3.12.2 entitles *Affected Participants* to compensation in the event that they are affected by an *AEMO intervention event*, specifically in this case by a *direction* given by AEMO to a third party in accordance with clause 4.8.9. The direction giving rise to this claim (summarised in 2.1.2 above) was made pursuant to clause 4.8.9. As a result, the trading intervals to which this claim applies are *intervention pricing trading intervals*.

AEMO determined compensation but then received a claim for compensation by the *Affected Participant* in excess of that determination. AEMO, pursuant to clause 3.12.2 (l), has referred ***Claim 4's*** *Affected Participants adjustment claim* to an independent expert as this claim is greater than $100,000.

4.1 Circumstances of the claim

The *Affected Participant* in ***Claim 4*** was affected by a direction issued to a VIC generator at 10:30 hrs on 1 December 2016, as set out in section 2.1.2 above. During the brief period of operation of the directed participant in VIC, FCAS Lower prices in SA rose from close to zero to very high levels. When the directed generator complied with the direction, FCAS Lower prices in SA fell back to close to zero (see Figure 1).

Figure 1. FCAS Lower and energy prices in SA during direction to VIC generator



Note: FCAS prices were capped at $300 because the *cumulative price threshold* in SA had been met. FCAS prices absent this cap would have been considerably higher.

Synergies understands that this price change arose because of a shortage of available FCAS Lower in SA when the directed participant was generating and certain system constraints were binding.

AEMO has determined that the period for the purpose of compensation is from DI ending at 10:35 hrs on 1 December 2016 to DI ending at 15:45 hrs on 1 December 2016. Intervention pricing was not implemented in this period. AEMO has indicated that the *direction* was required to maintain power system security in VIC.

4.2 AEMO requirements

Under clause 3.12.2 (c), AEMO is required to inform the *Affected Participant* of the level of *dispatch* that would have occurred but for the intervention event, and the amount it would have received based on this hypothetical level of dispatch, less the actual *trading amounts*[42] due to the *Affected Participant*.

On 30 December 2016, AEMO provided to the *Affected Participant*, by email: the estimated levels of dispatch in MW that the scheduled generating unit would have been dispatched at had the direction not occurred; and amounts equal to the estimated trading amounts that would have been received had the direction not occurred, based on the estimated level of dispatch, less the relevant *trading amounts* applicable to the *Affected Participant's* final settlement statement. Based on these figures, AEMO estimated a total compensation for the *Affected Participant*. AEMO stated that:[43]

> The compensation amounts were calculated using a 'What-If' simulation to determine the What-If Dispatch Instructions for all generators in the NEM, had the Direction not occurred. The What-If simulation involved removing the Direction constraint from the Dispatch files between 01/12/2016 1035 hrs and 01/12/2016 1545 hrs and rerunning the files through the NEM Dispatch Engine (NEMDE).

AEMO's determination for compensation was based on the *trading amount* that the *Affected Participant* would have received from energy sales into the *spot market* absent the intervention (determined using the foregoing what-if simulation) minus the actual *trading amount* earned. In some of the *trading intervals* the *trading amounts* actually paid was in excess of the amounts in the what-if simulations. AEMO removed these negative figures from the compensation. Synergies considers this to be reasonable and that AEMO's determination of compensation in respect of energy under clause 3.12.2 is correct.

42 But excluding any compensation that may have been awarded due to the application of an administered price cap or floor pursuant to clause 3.14.6. Synergies is not aware of any claim having been made under this clause in respect of the relevant periods.

43 AEMO email dated 30 December 2016.

AEMO did not, however, take account of *market ancillary services* in its determination, the subject of the claim by the *Affected Participant*.

4.3 Submission of the affected party

On 3 January the *Affected Participant* issued a further claim for compensation under clause 3.12.2 (f). They supplied additional information on the claim for compensation on 21 March 2017. The claim related to revenue from *market ancillary services*. For expositional clarity we refer to the claim as 'compensation for foregone ancillary services revenue'.

The *Affected Participant* was in a positon to supply FCAS Lower at the time of the *direction*. Based on the foregoing circumstances, the *Affected Participant* in SA made a claim for compensation on the following basis:

- as a result of the *direction*, prices for FCAS Lower in SA were considerably lower than the prices of FCAS Lower that would have arisen without it, falling from $300/MWh to close to zero;[44]
- the FCAS pricing and dispatch conditions that persisted in SA in settlement period 21 of 1 December 2016, when the directed generator was operating, would also have persisted across settlement periods 22-25 had AEMO not made the *direction*; and
- the amount of compensation payable for periods 22-25 should therefore reflect these hypothetical pricing and dispatch conditions for FCAS Lower that would have applied but for the *direction*, less actual payments for those services over the same period.

In the absence of information from AEMO on the estimated level and price of FCAS Lower in SA but for the *direction*, the SA claimant proposed an approach whereby the quantity of FCAS Lower supplied by the claimant and the price for FCAS Lower in settlement periods 22 to 25 would be the same as the quantity and price in settlement period 21 when the directed generator was in fact in generating.

4.4 Discussion

In order to evaluate the claim of the *Affected Participant* for additional compensation, it is necessary to determine whether clause 3.12.2 allows for compensation for foregone ancillary services revenues.

[44] At the time, the *cumulative price threshold* in SA had been met for FCAS Lower, so FCAS Lower prices were capped at $300/MWh. Had the cumulative price threshold not been met, FCAS Lower prices would have exceeded $10,000/MWh between 10:00 hrs and 10:40 hrs absent the *Direction*.

4.4.1 Objective of clause 3.12.2

Clause 3.12.2 sets out how compensation should be determined for *Affected Participants*. It states, in clause 3.12.2 (a) (1) that the compensation:

> will put the *Affected Participant* in the position that the *Affected Participant* would have been in regarding the *scheduled generating unit*… had the *AEMO intervention event* not occurred.

This points towards an assessment based on a comparison of the actual position of the *Affected Party* with the position they would have been in 'but for' the *direction*. This is supported by clause 3.12.2 (c) which requires AEMO to provide information to the *Affected Participant* on *dispatch* in MW that would have occurred but for the *direction*, the *trading amount* for that level of *dispatch* but for the *direction*, and the actual *trading amount*. AEMO complied with this requirement in respect of the *spot market* on 30 December 2017.

Clause 3.12.2 (a) (1) does not precisely codify which of the various possible sources of hypothetical revenue should be considered (i.e. revenue that might have been available to the *Affected Participant* from the different markets operated by AEMO had the intervention not occurred). Clause 3.12.2 (c) can be construed to require AEMO to supply the estimated level of dispatch of *market ancillary services* and the estimated *trading amount* for those ancillary services, but for the *direction*. For example, the term *dispatch* used in clause 3.12.2 (c) applies equally to energy or ancillary services, being defined thus:

> The act of initiating or enabling all or part of the response specified in a *dispatch bid*, *dispatch offer* or *market ancillary service offer* in respect of a *scheduled generating unit*, *semi-scheduled generating unit*, a *scheduled load*, a *scheduled network service*, an *ancillary service generating unit* or an *ancillary service load* in accordance with rule 3.8, or a direction or operation of capacity the subject of a *reserve contract* or an instruction under an *ancillary services agreement* as appropriate.

To assess whether clause 3.12.2 also extends compensation for foregone ancillary services revenue, it is necessary to examine the specific factors that must be considered in assessing compensation.

4.4.2 Factors that must be considered

The broad objective of clause 3.12.2 set out above would appear to be consistent with compensating *Affected Participants* for ancillary services revenues they may have foregone as the result of the direction.

However, clause 3.12.2 exhaustively sets out the factors that must be considered in restoring the *Affected Participant's* position. Specifically, clause 3.12.2 (a)(1) states that 'solely' those items listed in clause 3.12.2 (j) can be considered in an assessment of compensation. The term 'solely' expressly directs that no other factors can be considered in an assessment of compensation. Clause 3.12.2 (j) sets out the that the following must, as appropriate, be taken into account:

> (1) the direct costs incurred or avoided by the *Affected Participant* in respect of that *scheduled generating unit* or *scheduled network service*, as the case may be, as a result of the *AEMO intervention event* including:
>
> > (i) fuel costs in connection with the *scheduled generating unit* or *scheduled network service*;
> >
> > (ii) incremental maintenance costs in connection with the *scheduled generating unit* or *scheduled network service*; and
> >
> > (iii) incremental manning costs in connection with the *scheduled generating unit* or *scheduled network service*;
>
> (2) any amounts which the *Affected Participant* is entitled to receive under clauses 3.15.6 and 3.15.6A; and
>
> (3) the *regional reference price* published pursuant to clause 3.13.4(m).

There is no provision in clause 3.12.2 (j) for AEMO or the independent expert to consider any other factors that they may consider relevant to determining the position of an *Affected Participant* but for the direction.

We review each of these factors in turn.

4.4.3 Direct costs

In the current instance, clause 3.12.2 (j) (1) is not relevant as no claim has been made by the *Affected Participant* as regards these costs. Accordingly, it is not appropriate to consider direct costs in this determination.

4.4.4 Entitlements under clauses 3.15.6 and 3.15.6A

Clause 3.15.6 sets out the calculation of the *trading amount* for actual *spot market* transactions based on the *adjusted gross energy*, *intra-regional loss factor* at a *connection* point, and *regional reference price* in $/MWh. Essentially, it sets out the amounts owing for generation into the energy spot market within a *trading interval*. Clause 3.15.6A refers to the calculations of the *trading amount* for ancillary services, similarly setting out the amounts owing for ancillary services provided by the generator (in this instance) into the ancillary services markets in a *trading interval*.

Clause 3.15.6A applies to ancillary services. Notwithstanding, Synergies does not consider that reference to this clause can be considered, on its own, to establish that clause 3.12.2

allows for the compensation of foregone ancillary services revenue. We base this on the wording of clause 3.12.2 (j) (2) which refers to any amounts which the *Affected Participant* is entitled to receive.

The entitlement for amounts under clauses 3.15.6 and 3.15.6A derives from the actual provision of energy or ancillary services, not from some hypothetical provision of services as might be estimated in a 'but for' test. Clauses 3.15.6 and 3.15.6A determine *trading amounts* which result from a *transaction*. The AEMO's calculation of an estimated *trading amount* under clause 3.12.2 (c) (1) (ii) (A) does not meet the definition of a *transaction*. No *transaction* can reasonably have been said to have taken place as the result of a simulation of a hypothetical set of transactions for the purposes of a 'but for' test. A 'but for' estimation is therefore not an entitlement under clause 3.12.2 (j) (2), so clause 3.12.2 (j) (2) does not extend compensation for foregone ancillary services provision.

In our view, clause 3.12.2 (j) refers to clauses 3.15.6 and 3.15.6A in so far as they are necessary in order to determine the *trading amounts* that the *Affected Party* are entitled to from the energy and ancillary services they provided, so as to then determine whether any compensation in excess of these entitlements is warranted. This is particularly important when a claim for compensation indicates that *trading amounts* under clauses 3.15.6 and 3.15.6A are less than cost incurred as set out in 3.12.2 (j) (1).

4.4.5 The regional reference price

The *regional reference price* is the *spot price* at the *regional reference node*, being the price for electricity in a *trading interval* at a *regional reference node* or a *connection point* as determined in accordance with clause 3.9.2. AEMO is obliged to publish this price within 5 minutes of the actual trading interval. *Spot price* is expressly not an *ancillary services price* for a *market ancillary service*, the prices of which are determined in accordance with a different clause 3.9.2A.

Clause 3.12.2 requires consideration of the *regional reference price* in determining compensation or an *Affected Participant*, and therefore requires that the spot price for energy is considered. It does not require consideration of *ancillary services prices*. This indicates that compensation under clause 3.12.2 is confined to foregone *spot market* revenue or circumstances where costs as defined in clause 3.12.2 (j) (1) are greater than *trading amounts* under cls 3.15.6 and 3.15.6A.

Furthermore, because the factors set out in clause 3.12.2 (j) must be taken into account and are the sole factors that can be considered, clause 3.12.2 should be read to exclude consideration of *ancillary services prices* in determining compensation.

4.4.6 Other considerations

If clause 3.12.2 was construed to allow compensation for foregone ancillary services revenues, AEMO would need to supply the estimated level of *dispatch* and estimated *trading amount* for each of the relevant market ancillary services that would have arisen absent the direction. Synergies is not aware of these having been supplied, but understands that AEMO can provide them if required.

Furthermore, even if clause 3.12.2 did allow for such compensation, the approach for estimating such compensation presented by the claimant does not appear to be consistent with the factors that must be solely considered in determining compensation. In particular, it refers to *market ancillary services* prices which are not included within clause 3.12.2 (j), and does so for periods that were not *intervention pricing trading intervals.*

4.4.7 Determination

There is some ambiguity in clause 3.12.2 as to whether it allows for compensation for foregone ancillary services revenue. We conclude that it does not, for the following reasons:

- the set of criteria that must be considered and which can solely be considered make no express reference to *ancillary services prices* but do expressly reference *spot market prices* in the form of the *regional reference price*. This indicates that compensation is intended to be confined to foregone energy *spot market* revenues;
- in so far as clause 3.12.2 alludes to ancillary services, it does not do so in a way that indicates an intention to allow for the compensation of foregone ancillary services revenue; and
- the approach that the claimant set out for determining its claim is not confined solely to the factors set out in clause 3.12.2.

4.5 Conclusion

For the reasons set out above, we have determined that AEMO's determination under clause 3.12.2 for compensation for the *Affected Participant* in SA as a result of the direction in VIC appears to be correct from the information that AEMO has supplied. We do not consider that clause 3.12.2 allows for compensation for foregone ancillary services revenue nor, if it did so, that the method put forward by the *Affected Participant* for estimating that compensation is consistent with the requirements of clause 3.12.2. We therefore consider that the *Affected Participant's* claim for additional compensation should not be allowed.

In reaching this determination, we are mindful that there are ambiguities in clause 3.12.2 that we have had to resolve. It is difficult to determine whether the purpose of clause 3.12.2 is to compensate more generally for foregone revenues or, consistent with other some other compensation clauses in the NER, to ensure that revenues earned by an *Affected Participant* are not less than the costs that it incurs. If it is the former, it is difficult to determine whether it refers to all possible sources of foregone revenue.

If the intention of the NER was to allow or disallow for compensation of *Affected Participants* for foregone ancillary services revenues, then simple changes to clause 3.12.2 in the form of an express inclusion or exclusion of such compensation would remove any doubt that market participants may face.

Although it has not been a consideration in this determination, we are also concerned that compensation to *Affected Participants* for foregone ancillary services revenue could create problems for the NEM. The prices for market ancillary services have the potential to be quite sensitive to changes in network status and to changes in participant behaviour (and possibly 'gaming')[45] due to their relatively small volumes and more concentrated supply. This is particularly likely at times when AEMO has to make directions.

Synergies does not consider that, as currently written, the NER allow for compensation of *Affected Participants* for foregone *market ancillary services* revenues. It does allow compensation for foregone energy revenues. There is no clear rationale within the NER (or driven by the objectives of the NEM) for this differential treatment other than, perhaps, the complexities that might arise in compensating foregone *market ancillary services* revenues. This may be a matter that should be considered in any future review of the compensation framework.

45 Synergies notes that it is not uncommon for generators to change their ancillary services offers and availability at short notice.

5 Concluding remarks

Based on the foregoing, we have determined that the fair payment prices for ***Claim 2*** and ***Claim 3*** under clause 3.17.7A are both zero, that ***Claim 4*** for compensation as an *Affected Participant* for foregone ancillary services revenues should not be accepted, that ***Claim 4*** for compensation for foregone spot market revenue is appropriate, and that ***Claim 1*** for additional compensation for loss of revenue under clause 3.15.7B should be accepted. The total amount of compensation for these *directions* is $32,948.59 in respect of clause 3.12.2 and $125,552.29 in respect of 3.15.7B.

The *Directed* and *Affected Participants* have been individually informed of these determinations, the reasons for them, and the amount of compensation.

5.1 Comments on compensation for *directions* in the NER

In the course of making these determinations, we have identified a number of difficulties with the compensation provisions of the NER which we believe should be noted.

The four clauses, 3.12.2, 3.15.7, 3.15.7A and 3.15.7B do not have a clear common set of principles. They can be construed to refer to, *inter alia:* costs, opportunity costs, foregone revenue, average prices or fair prices. Synergies believes that the compensation rules for *direction* within the NEM would benefit from a clearer articulation of purpose, such as whether they are designed to compensate *directed participants* for the revenue foregone, any avoidable costs incurred, some other definition of costs arising as a result of the *direction*, or the value of the directed services.

Synergies does not view compensation for constrained off generation by *direction* as being consistent with the overall NEM design, in part because we do not consider that the use of a *direction* rather than standard dispatch instructions is a sufficient basis for distinction. If it were deemed a sufficient basis for compensation, clause 3.15.7A is poorly suited. The overall reduction in generation that results from a *direction* can be determined using approaches that are already set out in the NER, and the value of the lost generation is similarly amenable to estimation. Accordingly, it would be straight forward to include within the NER:

- an express indication of whether generators *directed* to reduce output should be compensated; and if so
- a precise calculation of the compensation based on *regional reference prices*, offer prices and the size of the reduction in generation.

In previous independent determinations, Synergies noted that clause 3.15.7B is not ideal for compensating peaking gas turbines directed to operate due to transmission constraints within a region (in that case, Queensland).[46] Clause 3.15.7B does not recognise that peaking gas turbines need to recover their fixed costs over the small number of hours in which they are required to operate, a significant share of which might arise under *directions*. In these instances, clause 3.15.7B only compensates to a ceiling of avoidable costs.

This is related to clause 3.15.7 which compensates for directed *energy* or *market ancillary services*. The compensation is based on the 90th percentile price over the previous year for that same service, yet this may be insufficient to cover operating costs for some generators. The compensation rules together may immunize directed generators from operating losses but do not obviously compensate the directed generators for the value they provide to the system. They can also give rise to difficulties when market prices for the different services are regulated inconsistently.

Clause 3.15.7B also provides for compensation for loss of revenue that results from a *direction*. ***Claim 1*** set out in section 3 above provides an example of its application. However terms such as 'loss of revenue' are not well defined in the clause, in marked contrast to the quite detailed exposition of the meaning of costs. Estimation of 'loss of revenue' also requires that a counterfactual is established. It would be helpful if the NER elaborated on both aspects.

Synergies also notes the ambiguities in clause 3.12.2, particularly whether it applies to *market ancillary services* as well as *energy*. Based on the text of the rules, Synergies does not consider that it extends to foregone *market ancillary services* revenue, but this is not a position founded in clear economic or efficiency principles. The differential treatment may be deliberate, or may be have arisen because the language of clause 3.12.2 has not been adapted as *market ancillary services* were introduced.

In Synergies view, some types of *directions* might be better managed through other arrangements such as reliability contracts. These might extend to peaking gas turbines in far north Queensland during tropical storms or to the management of SA islanding.

Finally, in so far as these compensation arrangements are triggered by *directions*, we had some difficulty in determining whether *directions* were essential, preferred or merely convenient standard practice, and whether the distinction would be relevant to compensation arrangements. Similarly, it is not clear how intervention pricing, which is not mandatory when *directions* are in operation, should affect compensation.

These are matters that AEMO and the AEMC may wish to consider in any future review of the compensation arrangements for *directed* and *Affected Participants*.

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46 Synergies (July 2015) *Additional Compensation for Directions to North Queensland Generators on 20th February 2015 - FINAL REPORT*