SLC

Independent Expert Final Determination of Additional Compensation ‘Package 2’ Directions Between February 2nd and February 9th 2020

Final Public Report and Assessment Prepared for AEMO

Sam Lovick Consulting
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www.lovickconsulting.com

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1. Introduction

This report is prepared for the Australian Energy Market Operator (AEMO) in accordance with the requirements of clause 3.12.3 of the National Electricity Rules[i] (NER).

Sam Lovick Consulting (SLC) was appointed by AEMO as an independent expert to determine clause 3.15.7B additional compensation owing for 'package 2' claims by *Directed Participants* arising from *directions* in South Australia between Friday, 31 January 2020 and Sunday, 9 February 2020. This related to seven *directions* covering periods between 2 February 2020 to 9 February 2020:

- to remain synchronised, follow dispatch targets and enable lower 6 second and lower 60 second frequency control ancillary services (FCAS) from 08:00 hrs 4 February 2020 to 15:10 hrs 4 Feb 2020[ii] ('Claim A');

- to synchronise, follow dispatch targets and enable raise 6 second, lower 6 second and lower 60 second FCAS from 06:30 hrs 2 February 2020 until 16:30 hrs 2 February 2020 ('Claim 1');

- to remain synchronised and follow dispatch targets from 20:00 hrs 2 February 2020 until 10:30 hrs 3 February 2020 ('Claim 2');

- to synchronise and follow dispatch targets from 04:30 hrs 8 February 2020 until 16:30 hrs 9 February 2020 ('Claim 3');

- to remain synchronised, follow dispatch targets and enable raise 6 second, lower 6 second and lower 60 second FCAS from 08:30 hrs 2 February 2020 until 16:30 hrs 2 February 2020 ('Claim 4');

- to remain synchronised and follow dispatch targets from 11:30 hrs 4 February 2020 until 16:30 hrs 9 February 2020 ('Claim 5'); and

- to remain synchronised, follow dispatch targets and enable raise 6 second, lower 6 second and lower 60 second FCAS from 08:00 hrs 2 February 2020 until 16:30 hrs 2 February 2020 ('Claim 6').

AEMO determined that these were *directions* for *system strength services* and FCAS necessary to maintain the system in a secure operating state. The 7 *directions* covered two different generation companies.

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i National Electricity Rules Version 132 in operation from 1 January 2020 to 4 March 2020, available at https://www.aemc.gov.au/sites/default/files/2019-12/NER%20v132%20full.pdf (last viewed 7 June 2020). Unless otherwise stated, references to clauses within this report refer to this version of the NER.

ii In the Directions Information provided by AEMO, the cancellation time for one of the *directions* was erroneously reported as 15:10 hours 2 February 2020 leading. The directed services were also erroneously described as raise 6 second and raise 60 second respectively.

1.1. Circumstances of the *Directions*

On Friday 31st January 2020, the Heywood Interconnector tripped when a storm caused the collapse of several 500 KV transmission towers in Western Victoria on the Moorabool to Mortlake and Moorabool to Tarrone transmission lines. As a result of this transmission failure, SA operated as an island with no connection to the rest of the National Electricity Market (NEM). Islanded operation persisted for approximately two weeks until AusNet installed and energised a temporary transmission line allowing SA to re-synchronise with the remainder of the NEM. AEMO was required by its standard operating procedures to issue multiple *directions* to secure the operation of the SA island during this period including those identified above.

1.2. Compensation for the *Directed Participants*

AEMO determined compensation for these *directions* under clause 3.15.7, which defines a formula for compensating *Directed Participants* for the provision of *energy* and *market ancillary services* based on the 90th percentile *spot price* or *ancillary service price* over the preceding year. Two of the *directions* extended over two billing weeks. AEMO calculated clause 3.15.7 amounts separately for each billing week. AEMO informed the *Directed Participants* of these compensation amounts.

System strength services are neither *energy* nor *market ancillary services* within the NER so there is no formulaic mechanism for determining compensation for its provision. Clause 3.15.7A sets out how compensation to *Directed Participants* for services other than *energy* or *market ancillary services* should be determined. However, clause 3.15.7A(a1) excludes services where the *direction* would have been unnecessary had the *Directed Participants* made a *dispatch bid*.

Energy, *system strength services* and, to some degree, FCAS are joint products. Accordingly, had *dispatch bids* for *energy* or FCAS been made for these directed units, there would not have been a need for *directions* for *system strength services*. Accordingly, clause 3.15.7A is not enlivened. (See endnote 1)

The *Directed Participants* sought additional compensation under clause 3.15.7B in respect of the foregoing *directions*. All these claims met the thresholds set out in clause 3.15.7B(c)(1) for referral to an independent expert.

1.3. Draft and Final reports

In accordance with clause 3.12.3 (c), we published a draft public report on 15th June 2020 and provided draft determinations of compensation to the *Directed Participants* on the same date. We invited the *Directed Participants* to make further submissions. We received several submissions which are addressed in this report. In addition, AEMO provided some revised figures on settlement amounts already paid to *Directed Participants*.

2. *Directed Participants'* claims

AEMO provided SLC with details of the clause 3.15.7 compensation to and correspondence with the *Directed Participants* concerning their clause 3.15.7B claims. In addition, SLC called for submissions from the *Directed Participants* as required by clause 3.12.3(c)(2) prior to preparing this report. The *Directed Participants* submitted additional information in support of their claims.

2.1. Clause 3.15.7B claims

There were three cost elements to claims related to six of the *directions* (Claims 1-6):

- the costs of purchasing fuel to provide the directed services;
- in two of the claims, the costs of having to start the directed units to be able to provide the directed services; and
- a share of the charges levied by AEMO *market generators* to recover the costs of Contingency Raise FCAS.

For each *direction* they claimed these costs minus the amount of compensation received for directed *energy* calculated according to clause 3.15.7.

There was no claim for start costs in Claim A. In addition, Claim A deducted compensation for directed FCAS, directed *energy*, and revenue from non-directed FCAS from their costs in their final claim.

2.2. Initial submissions

Both *Directed Participants* provided within the prescribed time limit in respect of each *direction*, a letter summarising the compensation that was sought, signed by an officer, certifying that data supplied was true and correct as required by clause 3.15.7B(b)(3). They also provided spreadsheets detailing the calculations made to determine the amount of additional compensation. The *Directed Participants* also supplied copies of invoices for fuel supplied covering the periods of the *directions.*

2.3. Further submissions

Both *Directed Participants* made submissions in response to the draft report. The submissions did not relate to the calculations of the amounts of compensation but to shortcomings in the requirements of the NER for determining additional compensation in these circumstances.

One *Directed Participant* stated that '*system strength should also be compensated for as well as the associated costs of providing the service*', noting that as '*there is currently no system strength market in the NEM that would allow pricing to be transparently determined [the* ***Directed Participant****] believes that the pricing should be based on the cost of provisioning the service in an efficient manner.*'

The *Directed Participant* suggested that the compensation should be linked to the costs of synchronous condensers in South Australia, citing the Australian Electricity Regulator's final decision on the ElectraNet Main Grid System Strength Project contingent funding from

August 2019.[iii] If *system strength services* could be compensated under clause 3.15.7A, the approach suggested by the *Directed Participant* would be apt. Unfortunately, for the reasons set out in section 1.2, clause 3.15.7A(a1) precludes this approach.

The *Directed Participant* also noted that in FY2020 there 2,371 hours of *directions* in South Australia. For close to a quarter of the year, *directions* were in place, many of which were needed to ensure system strength. It clearly is not desirable for the NEM to operate under *directions* for such a large proportion of the time. If *directions* are required so often, it is not appropriate that the rules limit compensation under the additional compensation provisions for *directed services* to what is, in effect, marginal cost. That is the effect of the rules as regards system strength.

Endnote 1, which was included in the draft report, elaborates on this issue. We have sympathy with the position of the *Directed Participant* and would support future rule changes in respect of system strength which address their concerns.

A second *Directed Participant* noted the practical difficulties in complying with the evidentiary requirements of clause 3.15.7B, particularly fuel costs when fuel may be supplied under a portfolio of different supply contracts, and where fuel supply contracts may be subject to confidentiality agreements. They suggested that a short-term spot price for fuel may be a more sensible metric in additional compensation claims.

It is, of course, important to minimise the costs of making compensation determinations. For the *Directed Participant* that made this observation, the costs of independent expert determination plus the compliance costs incurred by the *Directed Participant* are large in comparison with the overall amount of compensation. However, allowing spot prices as a proxy for fuel costs would run counter the objectives of clause 3.15.7B that aim only to ensure that *Directed Participants* do not incur operating losses. We note their concerns.

iii https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20ElectraNet%20-%20SA%20system%20strength%20contingent%20project%20-%2016%20August%202019.pdf

3. Clause 3.15.7B compensation provisions of the NEM

Clause 3.15.7B compensates *Directed Participants* for (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 3.14.5A(g), clause 3.15.7(e) 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*.

3.1. Net direct costs

Neither generator made a claim for lost revenue under clause 3.15.7B(a)(1), only for additional net direct costs incurred.

'Net direct costs' is not a defined term in the NER, but clause 3.15.7B(a3) sets out, without limitation, seven examples of net direct costs including fuel costs. It is clear from these examples that the term 'net direct costs' encompasses all costs incurred by the *Directed Participant* that would not have been incurred absent the *direction*, and this is the interpretation that has been adopted in the past by independent experts making clause 3.15.7B determinations.

Fuel costs and start costs (which are predominantly fuel related) clearly meet this definition. None of the seven examples of net direct costs in clause 3.15.7B(a3) exactly matches Contingency Raise FCAS recovery charges. Clause 3.15.7B(a3)(6) perhaps comes closest:

> other costs incurred in connection with the relevant *generating unit* or *scheduled network services*, where such costs are incurred to enable the *generating unit* or *scheduled network services* to comply with the *direction*.

But it cannot be said that Contingency Raise FCAS recovery charges as such '*enable* the generating unit… to comply with the direction' (emphasis added).

Nevertheless, due to the *direction*, the *Directed Participants* became liable for *trading amounts* under clause 3.15.6A(f) proportional to their *generator energy* in SA as a share of aggregate *generator energy* in SA. There is no exception in clause 3.15.6A(f) for generators that are directed to provide services. If the generators had not been directed, they would not have produced any *generator energy* and would not have been charged for Contingency Raise FCAS recovery. Accordingly, Contingency Raise FCAS recovery is an additional net direct cost; it would not have been incurred absent the *direction*.

AEMO provided settlement data on Contingency Raise FCAS recovery charges which the *Directed Participants* used to determine their compensation claims.

3.2. Adjustment for revenues received

To determine total compensation, clause 3.15.7B(a)(2) requires that compensation for the directed services calculated according to clauses 3.15.7 and 3.15.7A is deducted from net direct costs. Clause 3.15.7B(a)(3) requires that revenues defined in clause 3.15.6(c) are also deducted, specifically revenue earned by the *Directed Participant* during the *direction* 'from any service, other than the service the subject of the *AEMO intervention event*'.

3.2.1 Revenues from non-directed services

One *Directed Participant* made no clause 3.15.7B(a)(3) deductions. In contrast, the other deducted the revenue the *trading amounts* they received for the non-directed *market ancillary services* that they provided, specifically fast raise, slow raise, delayed raise, delayed lower and regulation raise.

In our view, the latter approach is correct. Revenue from non-directed *market ancillary services* should be deducted. The purpose of clause 3.15.7B is to ensure that *Directed Participants* do not make operating losses as a result of being directed. It is therefore appropriate to take account of all revenues that the *Directed Participant* receives during the *direction*. The plain language of the NER supports this view; the *Directed Participant* is entitled to the revenue from any other service which is not the subject of the *direction* (clause 3.15.6(c)), and that must be deducted from any claim (clause 3.15.7B(a)(3)). If revenue from the other sources (plus the revenue from the directed services) is greater than the net direct costs, then no additional compensation can be claimed.

3.2.2 Revenues from directed *market ancillary services*

The directed services in four of the claims, the Claim A and Claims 1, 4 and 6, were for *market ancillary services* (FCAS). Compensation for directed *market ancillary services* under clause 3.15.7 is based on the 90th percentile of *ancillary services prices* over the preceding year. AEMO determined the 90th percentile price and provided settlement data on compensation accordingly.

3.2.3 Defining revenues related to *system strength services*

The directed services in the other three claims were for *system strength services* only. This is not a *market ancillary service*. The NER makes no provision for determining a compensation amount for directed *system strength services*. Compensation cannot be based on clause 3.15.7A because, as noted in section 1.2, AEMO would not have had to make a *direction* had the *Directed Participants* made *dispatch bids* for *energy* or FCAS. This may not be the case for other generating technologies. Hence, in this instance the NER makes no payment for directed *system strength services* as such.

AEMO determined that compensation for *energy* generated while providing the *system strength services* should be calculated in accordance with clause 3.15.7 as if *energy* was the directed service. *Energy* compensation is therefore based on 90th percentile *spot price* over the preceding year. AEMO also calculated compensation for *energy* in this way for the *directions* for FCAS, indicating perhaps that these units were also providing directed *system strength services*. We follow this approach in determining additional compensation in these claims but note that the NER are somewhat ambiguous as regards compensation for *energy* under directions for *system strength services*.(See endnote 2)

4. Calculations of the claimed amounts

4.1. Clause 3.15.7B(a)(1) claims for loss of revenue

The *Directed Participants* did not seek additional compensation for loss of revenue under clause 3.15.7B(a)(1).

4.2. Clause 3.15.7B(a)(1) claims for additional net direct costs

The *Directed Participants* sought compensation for additional net direct costs under clause 3.15.7B(a)(1), for fuel costs, start costs and Contingency Raise FCAS recovery charges.

4.2.1 Fuel consumption

For each of six claims, Claims 1 to 6, the *Directed Participants* provided an Excel spreadsheet setting out aggregate fuel consumption in TJ across a group of generating units. This was evidenced with matching metering data. Fuel consumption for each *direction* in each period was based on the trading load under the *direction* in that period divided by the sum of all trading loads (to which the metered fuel data applied) in that same period. Specific metered fuel consumption was supplied for Claim A.

The approach used in Claims 1-6 implicitly assumed that all the generating units involved had the same heat rate. We investigated whether adjusting fuel consumption to take account of differences in heat rates would materially change the amount of compensation. We determined that the differences would be small. Furthermore, accurate and up to date heat rates were not available. Considering this and the small impact that the heat rate adjustment has on fuel consumption estimates for individual claims (smaller still across all claims in aggregate), we determined that the claimant's approach is appropriate.

Claim A included an incorrect estimate of fuel consumption in one settlement period of the *direction.* This was corrected.

Otherwise, the data and calculations submitted by the *Directed Participants* were sufficient to substantiate the claims in respect of fuel consumption.

4.2.2 Fuel costs

Both *Directed Participants* provided invoices for fuel purchases in February 2020 indicating the unit cost in $/GJ. In all cases, the quantity of fuel referenced in the invoices was enough to supply the *Directed Participants* across all the claims. This was appropriate evidence that the *Directed Participants* had incurred costs of at least the invoiced amounts for fuel used to supply the directed services.

One of the *Directed Participants* initially estimated their claim for fuel costs using the spot price for fuel at the time of the *direction*. They submitted that the spot price was the appropriate metric irrespective of the actual cash cost. We do not agree; in our view, the appropriate cost to use is the actual cash cost of the fuel incurred by the *Directed Participant*. The spot price would only be an appropriate metric if it were the cash cost paid. As a result, their compensation claim was adjusted to reflect the invoiced cost of fuel. The same party presented an invoice for fuel delivery costs which include both capacity and energy related components.

The former did not change with the amount of fuel consumed and was therefore excluded from the claim.

4.2.3 Start costs

Claims 1 and 3 included start costs. The *Directed Participant* submitted a spreadsheet for each claim detailing the type of start required delineated in terms of the duration of the prior off-time. Claim 1 might be described as a hot start after a short off-time. Claim 3 might be described as a warm start after a longer off-time. For each start they set out

- electricity consumption in MWh required to start and synchronise the unit;
- the quantity of fuel required to start and synchronise the unit;
- a fixed start cost; and
- the time taken to synchronisation.

As evidence in support of these costs, other than fixed start costs, they submitted an extract from a technical description of the plant contained in an Information Memorandum. This was sufficient to substantiate their claims except in respect of the fixed start cost component.

Total electricity costs were based on the arithmetic average SA regional reference price over the time taken to synchronise ($46.82/MWh for Claim 1, $38.04/MWh for Claim 3). Start fuel costs were calculated using the fuel cost set out in section 4.2.2. The fuel and electricity costs for starts meet the requirements of clause 3.15.7B for additional net direct costs.

The *Directed Participant* also included an estimate of fixed start costs in their claim for start costs. In discussion they submitted that this was to cover additional operating and maintenance (O&M) costs that are not fuel costs or electricity costs that would not arise absent the start. They were not able to evidence specific component costs as they do not routinely assemble this information.

Despite the lack of additional supporting data, we are reluctant to exclude fixed start costs from the claims as generators certainly incur start-related non-energy O&M costs. They have been recognised in prior clause 3.15.7B determinations of additional net direct costs for open cycle gas turbines. Furthermore, the *Directed Participant* submitted that AEMO itself recognises variable O&M costs in their forecasting and planning[iv] denominated in $/MWh although these are not, in our view, an exact parallel of fixed start costs.

There are studies of non-energy variable costs from plant cycling. For example, in 2012 Kumar et al[v] estimated the non-energy-related cycling costs for similar US-based plant as between US$25 and US$42 per MW (25th and 75th percentiles) for hot starts and US$36 and US$87 per MW for warm starts. At current exchange rates, the *Directed Participant's* claims for fixed start costs are below the lower bounds of these estimates and are small, representing between 2%

[iv] See, for example, https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-input-and-assumptions-workbook-v1-3-dec-19.xlsx?la=en

[v] Kumar N, Besuner , Lefton S, Agan D and Hilleman D (2012) Power Plant Cycling Costs, *National Renewable Energy Laboratory* available at https://www.nrel.gov/docs/fy12osti/55433.pdf (last viewed 10 June 2020).

and 4% of the claimed additional net direct costs. On this basis, we determine that the claims for fixed start costs should be accepted.

4.2.4 Charges for Contingency Raise FCAS recovery

The *Directed Participants* submitted spreadsheets detailing AEMO charges for Contingency Raise FCAS recovery separated into 6 second, 60 second and 5 minute classes. The spreadsheets allocated the sum of those charges in proportion to trading load (i.e. using essentially the same approach used to allocate fuel consumption to each unit, as set out in section 4.2.1). This reflects the allocation principles set out in clause 3.15.6A(f).

The approach is appropriate, and the data and calculations submitted were sufficient to substantiate their claims in respect of Contingency Raise FCAS recovery.

4.3. Revenue deductions

For the reasons set out in section 3.2, clause 3.15.7B requires that compensation for directed services and entitlements to *trading amounts* from non-directed services be deducted from costs to determine additional compensation. Table 1 summarise which services were and were not directed in these claims; non-directed services are market 'TA' indicating an entitlement to a *trading amount* for the service if it was provided by the *Directed Participant*.

Table 1. Directed and non-directed services

	Energy	6 Second Raise	60 Second Raise	5 Minute Raise	6 Second Lower	60 Second Lower	5 Minute Lower	Regulation Raise	Regulation Lower
Claim A	Directed	TA	TA	TA	Directed	Directed	TA	TA	TA
Claim 1	Directed	Directed	TA	TA	Directed	Directed	TA	TA	TA
Claim 2	Directed	TA	TA	TA	TA	TA	TA	TA	TA
Claim 3	Directed	TA	TA	TA	TA	TA	TA	TA	TA
Claim 4	Directed	Directed	TA	TA	Directed	Directed	TA	TA	TA
Claim 5	Directed	TA	TA	TA	TA	TA	TA	TA	TA
Claim 6	Directed	Directed	TA	TA	Directed	Directed	TA	TA	TA

4.3.1 Compensation for directed services

The *Directed Participants* provided spreadsheets detailing the compensation for each *direction* for directed *energy* and, where relevant, directed *market ancillary services*. The 90^{th} percentile prices, quantum of services provided, and compensation payments determined under clause 3.15.7(c) for these services were provided to them by AEMO in accordance with clause 3.15.7(f).

These compensation amounts need to be deducted from net direct costs under clause 3.15.7B(a)(2). One generator appropriately deducted compensation for directed *energy* and FCAS. The other generator appropriately deducted compensation for *energy* but failed to deduct compensation for directed FCAS in three of their claims. This was corrected.

4.3.2 Revenue for services that are not directed

In its initial claim, one generator did not deduct revenues to which it was entitled for non-directed services supplied during the *directions*. For the reasons set out in section 3.2.1, it was entitled to *trading amounts* for *market ancillary services* other than directed FCAS in accordance with clause 3.15.6(c). These must be deducted from any claim for additional compensation under clause 3.15.7b(a)(3). We estimated the *trading amounts* for all the services marked TA for each of the *directions* where this deduction was omitted and deducted them from net direct costs in order to assess the additional compensation. We based these adjustments on data supplied by AEMO.

The other generator deducted revenues for non-directed *market ancillary services* from its claim. However, their estimates of these revenues had calculation errors relating to the last 10-minute period of the *direction*. Their additional compensation claim was adjusted accordingly.

4.4. Total additional compensation

Based on the foregoing and in accordance with clause 3.12.3(c)((1)(B), we have determined that the total amount of clause 3.15.7B compensation payable to the *Directed Participants* in respect of the 7 *directions* in 'package 2' is $560,316 for billing week 6 and $83,691 for billing week 7.

End notes

1 A service such as system strength is not compensated under clause 3.15.7A (payment for services other than energy and market ancillary services) when, as in this case, system strength is a by-product of energy or market ancillary services supply. This is the effect of clause 3.15.7A(a1). This approach may be problematic if AEMO frequently resorts to directions to secure system strength services from conventional spinning generators.

When regions of the NEM become unbalanced — for example, the case when SA becomes islanded and there is insufficient system strength in the absence of local synchronised generators — and there is also surplus energy from renewable generation, spot energy prices (including 90th percentile prices over the previous year) are likely to below the cost of fossil, particularly gas, fired energy generation. These generators will prefer not to run absent a direction to do so. Accordingly, system strength will be insufficient absent a direction.

In such cases, the value of system strength services from, say, gas generation is higher, perhaps considerably so, than the value of energy. However, the price paid for the directed system strength services ends up being capped at the net direct costs of provision of the *energy* that is generated while the service is provided (under clause 3.15.7B). The gas-fired generators therefore earn nothing from providing the valuable system strength services. NEM participants that do not supply system strength services but rely upon their availability free-ride upon, particularly, fossil fuel-fired spinning generators that do provide them.

As the NEM's technological mix changes, the relative value of system strength services and energy/market ancillary services can be expected to change. If AEMO considers that directions will become increasingly necessary to secure the supply of system strength services, it might consider transitioning to some form of market mechanism to ensure supply.

2 There is some ambiguity in the NER concerning compensation when dealing with directed services that may have by-products, as in this case. AEMO determined that the *directions* were for *system strength services* and FCAS. The NER states in clause 3.15.6(c) that:

> A *Directed Participant* is entitled to the *trading amount* resulting from any service, other than the service the subject of the *AEMO intervention event*, rendered as a consequence of that event.

This recognises that generators will often have to supply or render one service, say *energy*, as a by-product of a *direction* to provide another service, say a *market ancillary service*. In which case, they are entitled to the revenue from that by-product. In these claims, the *Directed Participants* were able to supply *directed* FCAS and different non-directed FCAS services at the same time as joint products.

In these cases, *energy* could be viewed as a by-product of the *direction* to provide *system strength services*, and the *Directed Participants* would be entitled to the *trading amount* therefrom. If the revenue is less than the net direct costs of provision, then the *Directed Participant* can seek additional compensation under 3.15.7B taking account of that revenue from other services.

In discussions, AEMO stated that all the *directions* required that the *Directed Participants* synchronise [or remain synchronised} and follow dispatch targets. In so doing, they must perforce supply *energy*. Clause 3.15.7(a) states that:

> Subject to paragraphs (b) and (d1), *AEMO* must pay compensation to *Directed Participants* calculated in accordance with clauses 3.15.7, 3.15.7A and 3.15.7B, as the case may be, for any service which the *Directed Participant* was required to provide in order to comply with the *direction*.

AEMO indicated that by synchronising and following dispatch to supply *system strength services* the *Directed Participants* necessarily had to supply *energy*. The *Directed Participant* was therefore 'required' to provide *energy* to comply with the *direction*. As a result, *energy* supplied during the direction is compensated using clause 3.15.7(c) rather than clause 3.15.6.

This does not reconcile well with clause 3.15.6(c). Any generator directed to supply a service that necessitates synchronisation must supply *energy*. Should that *energy* always be compensated through the 90th percentile rule? A less constrained construction would be that clause 3.15.7(a) requires AEMO to compensate *Directed Participants* for the service for which the *direction* was issued, in this case *system strength services* not *energy*. The compensation for *system strength services per se* is zero. But the *Directed Participant* would be entitled to *spot prices* for any energy they produce. If this is insufficient to cover net direct costs, they can make a clause 3.15.7B claim.