# AEMO Direction to a NSW Participant on 24 Jan 2019 to Operate a Unit as a Synchronous Condenser

AEMO

17 July 2019

**FINAL REPORT**

IES Advisory Services

# Disclaimer

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# Executive Summary

IES has been appointed by AEMO as the Independent Expert pursuant to NER clause 3.15.7A to determine the fair payment price for services provided under direction by AEMO. *Directed Participant*

*Directed Participant* was directed to synchronise a generator at 1639 hrs on 24 January 2019 and to remain in service as a synchronous condenser. AEMO has advised the direction was needed to increase the power flow into Victoria on the Victoria to New South Wales interconnector to reduce the amount of load shedding that took place in Victoria on that day.

A draft determination of the fair payment price was published in a draft report. In fulfilment of clause 3.15.7A(c)(2)(iv), *Directed Participant* was invited to make a submission on the matters contained in the draft report. *Directed Participant*'s received submission contained new information that was not available to IES at the draft report stage on confidentiality grounds.

In determining the final fair payment price in accordance with clause 3.15.7A of the NER, IES has considered methodologies in Australia and overseas markets, relevant contractual arrangements and took into account the submission received.

The submission refers to an offer that *Directed Participant* made in response to an invitation to tender by AEMO for services comparable to the directed service. The offer contains a pricing mechanism the details of which are confidential. However, the offer did not result in a contractual arrangement between *Directed Participant* and AEMO and therefore, there was no contractual obligation on *Directed Participant* to provide the service.

The NER contemplates compensation to a directed participant, under similar circumstances, based on additional net direct costs, which is broadly consistent with the overseas markets reviewed. The services provided under direction are described in an agreement between *Directed Participant* and AEMO from 2013 to 2018. The agreement, which expired in July 2018, a few months before the direction on 24 January 2019, describes an a pricing mechanism different from that contained in the offer. In the opinion of IES, the pricing mechanism described in the agreement is a suitable basis for determining the fair payment price based on additional net direct costs. The final determination of the fair payment price is $16,874.30, the same amount arrived at in the draft determination.

The submission makes important points worthy of consideration outside the scope of this report. The report contains more detail and analysis.

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# Appendices

# 1 Introduction

IES has been appointed by the Australian Energy Market Operator (AEMO) as the Independent Expert to determine a fair payment price for services provided by a *Directed Participant*, in accordance with NER clause 3.15.7A.[1] The fair payment price relates to the period on 24 January 2019 when *Directed Participant* was directed to synchronise a generator in order to maintain power system security. Operating the directed generation unit in synchronous mode allowed increased power to flow securely from NSW into Victoria and reduced the amount of load shedding in Victoria on that day.

## 1.1 Background and direction to *Directed Participant*

AEMO has published a report relating to the load shedding incident in Victoria and provided the following background information regarding the events leading to the direction to *Directed Participant*.

On 24 January 2019, south-eastern Australia experienced hot temperatures and high operational demands. These elevated temperatures, coupled with expected supply conditions and limitations on southern flows through the Snowy – VIC cutset, resulted in consistent forecasts of low reserves on the afternoon of 24 January 2019 in South Australia and Victoria. Insufficient market response was provided to alleviate the forecast reserve shortfalls. Subsequently, AEMO managed the reserve shortfalls by:

- Between DI ending 1605 hrs and DI ending 2230 hrs on 24 January 2019, AEMO activated Reliability and Emergency Reserve Trader (RERT) contracts in South Australia and Victoria.
- Between DI ending 1640 hrs and DI ending 2115 hrs on 24 January 2019, AEMO issued a direction to a New South Wales Market Participant to maintain power system security. The aim of the direction was to maximise southern flows through the Snowy – VIC cutset, and to relax the relevant voltage collapse constraint (N^^V_NIL_1) to maintain the power system in a secure operating state. The direction event is summarised in Table 1.
- Between 1810 hrs and 2000 hrs on 24 January 2019, AEMO directed Ausnet to shed load as a result of a shortfall in available capacity reserves.

**Table 1 Summary of the New South Wales direction on 24 January 2019**

| Direction | Directed Participant | Issue time | Cancellation time | Explanation |
|---|---|---|---|---|
| **A generator** | *Directed Participant* | 1639 hrs, 24 January 2019 | 2115 hrs, 24 January 2019 | To synchronise a generator at 1639 hrs on 24 January 2019 and remain in service as a synchronous condenser. |

[1] Refer to AEMO's operating incident report for the NEM, Load Shedding in Victoria on 24 and 25 January 2019, 16 April 2019.

The remainder of the report contains the description of services and final determination, methodology and conclusion. Appendices A and B contain the constraint formulation and relevant excerpts from v117 of the NER respectively.

# 2 Description of services and final determination

## 2.1 Description of services provided

Clause 3.15.7A(c)(3)(i) requires the services provided to be described. AEMO's direction, as set out in Table 1, required *Directed Participant* '[t]o synchronise a generator at 1639 hrs on 24 January 2019 and remain in service as a synchronous condenser'. The issue and cancellation times of the direction are 16:39 and 21:15 on 24 January 2019. *Directed Participant* complied with AEMO's direction.

## 2.2 Final determination of the fair payment price for the services

Clause 3.15.7A(c)(3)(ii) requires the Independent Expert to set out its final determination of the fair payment price for the services provided.

The circumstances leading to the direction entitle *Directed Participant* to compensation. IES has determined the final payment price in accordance with 3.15.7A including taking into account the submission received as required by 3.15.7A(c)(3). The amount has been determined with reference to a relevant contract. There are ten trading intervals during the period of the direction, 16:40 to 21:15. IES has determined the total fair payment price amount pursuant to this direction to be $16,874.30. This amount does not include GST nor does it include interest payable in accordance with 3.15.7(b). The analysis and details are provided in the report below. Some of the details are referred to in general terms to protect commercially sensitive information.

# 3 Methodology

Clause 3.15.7A, Payment to *Directed Participants* for services other than energy and market ancillary services, sub-clause (c) requires the following:

> that the independent expert must, in determining the fair payment price of the relevant service for the purposes of clause 3.15.7A(c)(1), take into account:
>
> (i) other relevant pricing methodologies in Australia and overseas, including but not limited to:
>
> (A) other electricity markets;
>
> (B) other markets in which the relevant service may be utilised; and
>
> (C) relevant contractual arrangements which specify a price for the relevant service;
>
> (ii) the following principles:
>
> (A) the disinclination of Scheduled Generators, Semi-Scheduled Generators, Market Generators, Scheduled Network Service Providers or Market Customers to provide the service the subject of the direction must be disregarded;
>
> (B) the urgency of the need for the service the subject of the direction must be disregarded;
>
> (C) the *Directed Participant* is to be treated as willing to supply at the market price that would otherwise prevail for the directed services the subject of the direction in similar demand and supply conditions; and
>
> (D) the fair payment price is the market price for the directed services the subject of the direction that would otherwise prevail in similar demand and supply conditions;
>
> Additionally, 3.15.7A(c)(3) requires the independent expert to take the submissions received into account.

IES has observed these principles in arriving at its determination contained in this report.

## 3.1 Pricing methodology in Australia

IES has relied on v117 of the NER, the relevant version at the time of the direction. The direction was for a service to be provided in order to maintain system security in the event of a voltage collapse at Darlington Point on loss of the largest Vic generating unit or Basslink as documented in constraint N^^V_NIL_1 (see Appendix B ). According to this constraint, by synchronising this additional unit, which would provide reactive power in the event of a contingency event in Victoria, the power flow from NSW to Victoria could be increased securely. Such a contingency did not occur on the day although this fact is not relevant to this determination.

### 3.1.1 AEMO compensation to a *Directed Participant* under 3.15.7A

3.15.7A(a) specifies that '…AEMO must compensate a *Directed Participant* for the provision of services pursuant to a direction other than energy and market ancillary services, at the fair payment price of the services determined in accordance with this clause 3.15.7A.'

In order for a direction to be classified as a direction for services other than energy and market ancillary services it must satisfy subsequent clause 3.15.7A(a1) '…the need for the direction could not have been avoided by the central dispatch process had there been a dispatch bid, dispatch offer or rebid made consistent with the requirements [of specified clauses] for dispatch of plant relevant to that direction for one or more of…' energy and a market ancillary service.

AEMO has informed IES that '[i]nsufficient market response was provided to alleviate the forecast reserve shortfalls.' Based on the above, AEMO's direction is consistent with clause 3.15.7A(a1).

We turn to what the compensation should be based upon. The NER contemplates the compensation to comprise the loss of revenue, additional net direct costs and a reasonable return on the capital employed to provide the service, clause 3.15.7B(a). A *Directed Participant* may rely on this clause to claim additional costs in the case where they believe they are entitled to an amount larger than the determined compensation. This clause provides relevant guidance as to the compensation a *Directed Participant* is entitled to in the absence of relevant market-based benchmarks for the fair payment price. Since there is no loss of revenue to the *Directed Participant* in this case, the remaining components are the additional net direct costs and reasonable rate of return. Clause 3.15.7B(a3) provides detail on the cost components that can be reasonably included in arriving at the additional net direct cost.

## 3.2 Pricing methodologies in overseas markets

The report considers two large established markets in the continental USA. While the market design is not identical to the NEM, the methodologies applied in these markets are relevant to the service subject of the direction of this report. Matching international markets design to the NEM would have been material in other situations such as a service involving dispatch of energy or FCAS.

### 3.2.1 PJM

PJM is a Regional Transmission Organization (RTO) and market operator in the USA. According to their website, PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.[2]

PJM publishes rules for compensating generators for the provision of services. Compensation is based on the type of service and characteristics of the generator. Compensation in PJM for operating a generating unit in the condensing mode is based on costs incurred. Participants

[2] https://www.pjm.com/about-pjm/who-we-are/territory-served.aspx (accessed on 10 May 2019).

claiming such costs are required to document how these costs were arrived at and to present these records upon request. [3]

### 3.2.2 CAISO

The California Independent System Operator (CAISO) is an established market in the USA. Section 8 of the tariff relates to ancillary services. 8.2.3.3 Voltage Support 'If the CAISO requires additional Voltage Support, it shall procure this either through Reliability Must-Run Contracts or, if no other more economic sources are available, by instructing a Generating Unit to move its MVar output outside its mandatory range. Only if the Generating Unit must reduce its MW output in order to comply with such an instruction will it be eligible to recover its opportunity cost in accordance with Section 11.10.1.4.' [4]. The approach by CAISO indicates that a directed participant is entitled to compensation only if the generating unit reduces its dispatched quantity.

## 3.3 Other NEM markets in which the relevant service may be utilised

There are no other NEM markets in which this service may be utilised. This service is a Network Support and Control Ancillary Services (NSCAS) which is a non-market ancillary service.[5] The unit in question was not scheduled to operate in any other market.

## 3.4 Relevant contractual arrangements

In determining the fair price payment relating to the direction, 3.15.7A(c)(1)(i)(C) requires the Independent Expert to take into account 'relevant contractual arrangements which specify a price for the relevant service;'. A contract for the provision of NSCAS was in place between *Directed Participant* and AEMO between February 2013 and June 2018. NSCAS is a non-market ancillary service that may be procured to maintain system security or power transfer capability.

IES has reviewed this contract and found it relevant to determining a fair payment price for the service provided pursuant to the direction. The contract includes various performance obligations. The contract covers a number of power stations for the provision of the NSCAS service. Parameters relevant to a specific power station and its generating units are specified in the schedules. Schedule 3 of the agreement pertains to the relevant Power Station including generating unit 2, the unit involved in the direction. Clause 2 of Schedule 3, Description of NSCAS, describes the service in terms comparable to the explanation contained in AEMO's direction on 24 January to *Directed Participant* 'To synchronise a generator at 1639 hrs on 24 January 2019 and remain in service as a synchronous condenser.'

[3] PJM Manual 15: Cost Development Guidelines, Section 2.7 Synchronized Reserve. Revision 31, Effective Date February 15 2019

[4] http://www.caiso.com/Documents/Section8-AncillaryServices-asof-Nov6-2018.pdf (accessed on 13 may 2019). Note that this is the current version at the time of writing of this report.

[5] Refer to AEMO's website https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/Network-support-and-control-ancillary-services-procedures-and-guidelines (accessed 24 May 2019)

## 3.5 Submissions received

In determining the fair price payment relating to the direction, 3.15.7A(c)(3) requires the independent expert to take submissions received into account.

Following the publication of the independent expert draft report on the direction by AEMO to *Directed Participant*, *Directed Participant* made a confidential submission on 19 June 2019 in accordance with the intervention settlement timetable. There were no submissions from other parties.

IES had requested all relevant information from *Directed Participant* and AEMO on 13 May 2019. The information received from AEMO 23 May 2019 in response to this request, with *Directed Participant* copied in, consisted of the NSCAS Agreement between *Directed Participant* and AEMO dated February 2013 ("NSCAS Agreement") that expired in July 2018. In accordance with the NER IES must take the submission into account in determining the fair payment price. The submission is summarised in this report in accordance with 3.15.7A(c)(3)(iv).

- *Directed Participant* considers the NSCAS Agreement that expired in July 2018 not to be relevant for the determination. The reasons provided cannot be quoted due to confidentiality.

*Directed Participant* provided information about an offer ("The Offer") it made in response to an invitation to tender by AEMO. *Directed Participant* considers the fair payment price should be based upon The Offer as the services in AEMO's invitation to tender are more relevant to the services which AEMO directed *Directed Participant* to provide on 24 January 2019.

The pricing in The Offer contained a pricing mechanism the details of which are withheld due to confidentiality. *Directed Participant* expressed the view that should the NSCAS Agreement be relied upon then the fair payment price should be a higher amount.

## 3.6 Discussion

In determining the fair payment price IES must make its determination in accordance with NER clause 3.15.7A. The NER does not require the independent expert to determine whether AEMO could have avoided this direction had it entered into this or other arrangements. It is not within the scope of this report for IES to review AEMO's planning and the implications of entering or not entering into this contract along with other measures it took or could have undertaken.

Irrespective of whether The Offer can be considered as a relevant contractual arrangement, since there is no contract between AEMO and *Directed Participant* to provide this service, *Directed Participant* was not under a contractual obligation to incur costs mentioned in the submission. The *Directed Participant* did not have to incur costs contained in the Offer to carry out a contractual obligation. Therefore, it is not reasonable to include such amounts as compensation for additional net direct costs associated with complying with the direction. Since the additional net direct costs related to this direction do not include capital investment, there is no amount associated with the rate of return on capital employed to provide this service during the period of direction. Consequently, the only component remaining is the net additional direct cost component which we have based on the NSCAS Agreement that expired in July 2018.

Clause 2 of Schedule 3, Description of NSCAS, in the NSCAS Agreement, describes the service in terms comparable to the explanation contained in AEMO's direction on 24 January to *Directed Participant* 'To synchronise a generator at 1639 hrs on 24 January 2019 and remain in service as a synchronous condenser.' The NSCAS Agreement which expired in July 2018, a few months before the direction by AEMO, on 24 January 2019 contains a pricing mechanism aimed at recovering costs incurred when the unit is enabled in synchronous condenser mode. The pricing mechanism in Schedule 3 of the NSCAS Agreement is a reasonable basis for determining the fair payment price, based on additional net direct costs, to which *Directed Participant* is entitled under NER clause 3.15.7A for complying with the direction.

The amount payable by AEMO to *Directed Participant* for each trading interval during which the service is enabled is described in the NSCAS Agreement.

- The average intervention price during the period that the direction was in effect is $126.47 per MWh. TLF being the 2018-19 MLF for the relevant unit.[6]

IES has calculated the amount payable following the NSCAS Agreement pricing mechanism (adjusted for inflation) to be $16,874.30 for the ten trading intervals during the period of the direction. IES has determined that the fair payment price in respect of this direction is $16,874.30. This amount does not include GST nor interest payable under 3.15.7(b).

The submission by *Directed Participant* makes important points but they are outside the scope of this report.

[6] Refer to AEMO's report 'REGIONS AND MARGINAL LOSS FACTORS: FY 2018-19' published 13 July 2018 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2018/Marginal-Loss-Factors-for-the-2018-19-Financial-Year---updated-11-July-2018.pdf (accessed 24 May 2019)

# 4 Conclusion

IES has considered various approaches available and took the received submission into account in determining the fair payment price for the service provided pursuant to the direction. The NER contemplates compensation for the service provided based on additional net direct costs incurred by the *Directed Participant* in addition to a reasonable return on capital. This approach is consistent with that followed in overseas markets surveyed in this report. PJM rules compensate directed participants based on the additional net direct cost while CAISO rules do not compensate the directed participant.

IES has determined the fair payment price based on clause 3.15.7A of the NER to comprise additional net direct costs incurred in complying with the direction to operate the directed unit in synchronous condenser mode. The total fair payment price amount is **$16,874.30**. This amount does not include GST nor interest.

# Appendix A Formulation of Constraint

This appendix contains the formulation of the RHS of constraint N^^V_NIL_1 which is central to the direction. The term in the RHS of the constraint relating to the unit subject of the direction is not highlighted to maintain confidentiality.

**Constraint: N^^V_NIL_1**

**Constraint type:** LHS<=RHS
**Effective date:** 19/12/2018
**Author:** TLIU
**Version No:** 1
**Weight:** 35
**Constraint active in:** Dispatch and DS PASA, Predispatch and PD PASA, ST PASA, MT PASA
**5 Min Predispatch RHS:** Dispatch
**Active in PASA for:** LRC & LOR

**Constraint description:** Out = Nil, avoid voltage collapse at Darlington Point for loss of the largest Vic generating unit or Basslink
**Impact:** Vic - NSW Interconnector + Generators
**Source:** AEMO
**Limit type:** Voltage Stability
**Reason:** Avoid voltage collapse at Darlington Point for loss of the largest Vic generating unit or Basslink
**Modifications:** Updated based on latest limit advice
**Additional Notes:** Limit advice 23/11/2018. CCR4315

**RHS**
**Default RHS value=** 300

**Dispatch RHS=**
0.874 x **(** 1709 {Constant}
- 0.9578 x **( (** Max
**(**
MW flow north on the Basslink DC Interconnector,
Vic largest unit output MW
**) ) )**
- 0.8576 x [Summated MW loads at Yass, Wagga, Jindera, Darlington Pt & Broken Hill]
- 0.02102 x [Sum of NSW scheduled regional load plus non-scheduled wind generation]
+ 0.02102 x [Summated MW loads at Yass, Wagga, Jindera, Darlington Pt & Broken Hill]
+ 0.0959 x [SCADA MW output of Cullerin Range Windfarm]
+ 0.0959 x [SCADA MW output of Capital Hill Windfarm]
+ 17.01 x [Number of Tumut 1 Syn Cons In Service]

+ 17.01 x [Number of Tumut 2 Syn Cons In Service]
+ 60.31 x [Number of Tumut 3 Syn Cons In Service]
+ 54.52 x [Number of Murray 11-14 Syn Cons In Service]
+ 47.745 x [On status of the Woodonga 330kV Cap Bank]
+ 32.1 x [On status of the Dederang #1 220kV Cap Bank]
+ 70.3575 x [On status of the Dederang #1 330kV Cap Bank]
+ 70.3575 x [On status of the Dederang #2 330kV Cap Bank]
+ 32.472 x [On status of Wagga No. 1 132 kV capacity bank (80 MVAr)]
+ 20.295 x [On status of Wagga No. 2 132 kV capacity bank (50 MVAr)]
+ 32.472 x [On status of Wagga No. 3 132 kV capacity bank (80 MVAr)]
+ 23.76 x [On status of the Canberra #1 (120MVar) Cap Bank]
+ 15.84 x [On status of the Canberra #2 (80MVar) Cap Bank]
+ 23.76 x [On status of the Canberra #3 (120MVar) Cap Bank]
+ 23.76 x [On status of the Canberra #4 (120MVar) Cap Bank]
+ 16.688 x [On status of the Yass #1 (80MVar) capacitor bank]
- 15.124 x [On status of Darlington_Pt 33 MVAR #1(X5) shunt reactor]
- 7.333 x [On status of Darlington_Pt 16 MVAR #3 shunt reactor]
- 7.333 x [On status of Darlington_Pt 16 MVAR #4 shunt reactor]
+ 8.708 x [On status of Darlington_Pt 19 MVAR #1 shunt capacitor]
+ 9.166 x [On status of Darlington Pt No. 2 132 kV capacity bank (20 MVAr)]
+ 9.166 x [On status of Darlington Pt No. 3 132 kV capacity bank (20 MVAr)]
+ 0.3339 x [MVAr of Murray No. 1 330 kV 150 MVAr reactor. Value is negative when reactor in service]
+ 0.3339 x [MVAr of Murray No. 2 330 kV 150 MVAr reactor. Value is negative when reactor in service]
+ 0.3339 x [MVAr of Murray No. 3 330 kV 150 MVAr reactor. Value is negative when reactor in service]
+ 0.1945 x [MVAr of Yass No. 1 330 kV 150 MVAr reactor. Value is negative when reactor in service]
+ 0.1945 x [MVAr of Yass No. 2 330 kV 150 MVAr reactor. Value is negative when reactor in service]
+ 0.1945 x [MVAr of Yass No. 3 330 kV 150 MVAr reactor. Value is negative when reactor in service]
+ 11.216 x [On status of Queanbyn No.1 66kV capacitor]
+ 11.216 x [On status of Queanbyn No.2 66kV capacitor]
+ 3.342 x [MVAr of Cooma 132kV capacitor]
- 12.875 x [On status of Bannaby No.1 33kV reactor]
- 12.875 x [On status of Bannaby No.2 33kV reactor]
+ 9.719 x [Number of Eildon PS Units In Service]
+ 25.11 x [Number of Murray 1 (units 1 to 10) Units online (as Generators or Syncons)]
+ 20.95 x [Number of Dartmouth PS unit in service]
+ 12.24 x [Number of Bogong PS unit in service]
+ 3.044 x [Number of McKay Creek PS unit in service]
+ 7.96 x [Number of West Kiewa PS unit in service]
+ 0.5918 x [MW load on Pumps at Jindabyne]
- 84.43 {Statistical Margin}
- 45 {Operating Margin}**)**

# Appendix B Related excerpts from the NER

This appendix contains relevant excerpts from Chapter 3 of the NER v117, the current version of the NER at the time of writing of this report.

3.15.7….

(d) If at the time AEMO issues a direction:

(1) the *Directed Participant* had submitted a dispatch bid, dispatch offer or rebid acknowledged by AEMO in accordance with clause 3.8.8 for dispatch of the service that is to be dispatched in accordance with the direction; and

(2) the direction was issued because AEMO was prevented from dispatching the *Directed Participant*'s plant in accordance with that dispatch bid, dispatch offer or rebid due to a failure of the central dispatch process,

the *Directed Participant* is entitled to receive compensation for the provision of that service at a price equal to the price in that dispatch bid, dispatch offer or rebid acknowledged by AEMO in accordance with clause 3.8.8, as the case may be.

3.15.7A…

'(a) Subject to clause 3.15.7(d) and clause 3.15.7B, AEMO must compensate each *Directed Participant* for the provision of services pursuant to a direction other than energy and market ancillary services, at the fair payment price of the services determined in accordance with this clause 3.15.7A.

(a1) In this clause 3.15.7A, a *direction* is a *direction* for services other than *energy* and *market ancillary services* to the extent that the need for the *direction* could not have been avoided by the *central dispatch* process had there been a *dispatch bid*, *dispatch offer* or *rebid* made consistent with the requirements of clauses 3.8.6, 3.8.6A, 3.8.7, 3.8.7A or 3.8.8(d) (whichever is applicable) for *dispatch* of *plant* relevant to that *direction* for one or more of the following services:

(1) energy; and

(2) any one service of the market ancillary services.'

'(a2) For the avoidance of doubt, any component of a direction that satisfies clause 3.15.7A(a1) is to be considered for compensation under this clause 3.15.7A and clause 3.15.7B, as the case may be. Any other component of the direction that does not satisfy clause 3.15.7A(a1) is to be considered for compensation under clause 3.15.7 and clause 3.15.7B, as the case may be.'

3.15.7B Claim for additional compensation by *Directed Participants*

'(a) Subject to clauses 3.15.7B(a1) and 3.15.7B(a4), a *Directed Participant* entitled to compensation pursuant to clause 3.14.5A(d), clause 3.15.7 or clause 3.15.7A may, in accordance with the intervention settlement timetable, make a written submission to AEMO claiming an amount equal to the sum of:

(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(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.'

…

'(a2) Subject to clause 3.15.7B(a4), if a *Directed Participant* entitled to compensation pursuant to clause 3.15.7(d) considers that the amount notified pursuant to clauses 3.15.7(e) is less than the amount it is entitled to receive pursuant to that clause, the *Directed Participant* may, in accordance with the intervention settlement timetable, make a written submission to AEMO requesting compensation from AEMO for that difference.

(a3) For the purposes of the calculation of additional net direct costs pursuant to paragraphs (a)(1) and (a1)(1), the additional net direct costs incurred by the *Directed Participant* in respect of that scheduled generating unit, semi-scheduled generating unit or scheduled network services (as the case may be) includes without limitation:

(1) fuel costs in connection with the relevant generating unit or scheduled network services;

(2) incremental maintenance costs in connection with the relevant generating unit or scheduled network services;

(3) incremental manning costs in connection with the relevant generating unit or scheduled network services;

(4) acceleration costs of maintenance work in connection with the relevant generating unit or scheduled network services, where such acceleration costs are incurred to enable the generating unit or scheduled network services to comply with the direction;

(5) delay costs for maintenance work in connection with the relevant generating unit or scheduled network services, where such delay costs are incurred to enable the generating unit or scheduled network services to comply with the direction;

(6) 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; and

(7) any compensation which the *Directed Participant* receives or could have obtained by taking reasonable steps in connection with the relevant generating unit or scheduled network services being available.'