IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE

(Constituted for a determination as to compensation under Rule 3.16.2 of the National Electricity Rules)

JOINT SUBMISSION TO THE DISPUTE RESOLUTION PANEL

The Claimants listed in Schedule 1 (**Claimants**)

and

Australian Energy Market Operator Limited (**AEMO**)
(ABN 94 072 010 327)

A. Introduction

1. The italicised terms used in this submission are defined in the National Electricity Rules (***Rules***).[1]
2. Other terms and acronyms are defined in bold where they are first used in this submission. For convenience, they are also listed in **Schedule 2**.

B. Application

3. The Claimants are and were, at all material times, registered as *Market Generators* for the *generating systems* listed in **Schedule 1** (**Generating Systems**).
4. In February 2016, AEMO declared that two *scheduling errors* had occurred that affected the Generating Systems from the *dispatch interval* ending 0215 hr on 14 March 2012 to the *dispatch interval* ending 1800 hr on 7 April 2016 (**Scheduling Error Period**).[2]
5. Clause 3.16.2(a) of the *Rules* permits any *Market Generator* affected by a *scheduling error* to apply to the *dispute resolution panel* (**DRP**) for a determination as to compensation in respect of the *scheduling error*. The matters to be determined by the DRP are:
   (a) whether compensation is payable;
   (b) the amount of compensation to be paid to each Claimant from the *Participant compensation fund*;[3] and
   (c) the manner and timing of that payment.[4]
6. The Claimants seek compensation in respect of *spot market* losses.

C. National Electricity Rules

7. The applicable versions of the *Rules* and the dates during which each version was in effect during the Scheduling Error Period, are set out in **Schedule 3**.

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[1] Section C addresses the question of which versions of the *Rules* are relevant to the period during which the *scheduling errors* impacted the Claimants.
[2] AEMO may declare a *scheduling error* under clause 3.8.24(a)(2) of the *Rules*.
[3] Clause 3.16.2 (b) and (d).
[4] Clause 3.16.2(i).

8. The amendments made to the *Rules* during the Scheduling Error Period do not alter the effect of the provisions cited in this submission in a manner that is material to the matters relevant to the DRP's determination of compensation as a result of the *scheduling errors*.

D. AEMO and the National Electricity Market (NEM)

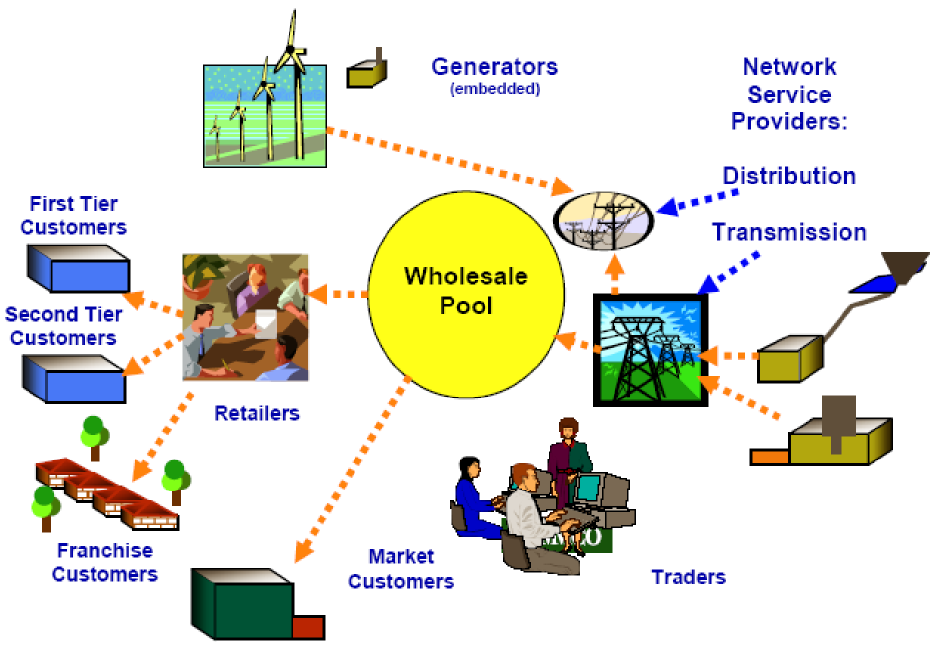
9. Sections D to H set out background information regarding the operation of the *NEM* and how *Scheduled Generators* and *Semi-Scheduled Generators* are *dispatched* in the *NEM*. This is included to provide context to the DRP.

10. AEMO operates and manages the *NEM*. The *NEM* is essentially two things: the physical infrastructure that keeps electricity flowing from producers to consumers, and a notional wholesale pool (or *spot market*) to which producers sell, and from which purchasers buy, electricity.

11. Electricity is dynamically produced to satisfy demand that varies instantaneously. The *NEM* facilitates the instantaneous matching of supply and demand through a centrally coordinated process managed by AEMO, called *central dispatch*.

12. Figure 1 depicts the relationships between different participants in the *NEM*.

Figure 1 – The National Electricity Market



13. The *NEM* is a gross pool. This means that all *Generators* whose power output enters the grid must 'sell' their output via the *market* conducted by AEMO, unless they are embedded in a *distribution network* and have already sold their output to the *local retailer* or to a consumer located at the same *connection point*.

14. In geographic terms, the *NEM* covers the supply of electricity to southern and eastern Australia. It operates on one of the world's longest *interconnected power systems*, a distance of more than 4,000 kilometres.

15. The *NEM* is divided into five *regions* for *market* pricing purposes:

(a) Queensland;

(b) New South Wales (incorporating the Australian Capital Territory);

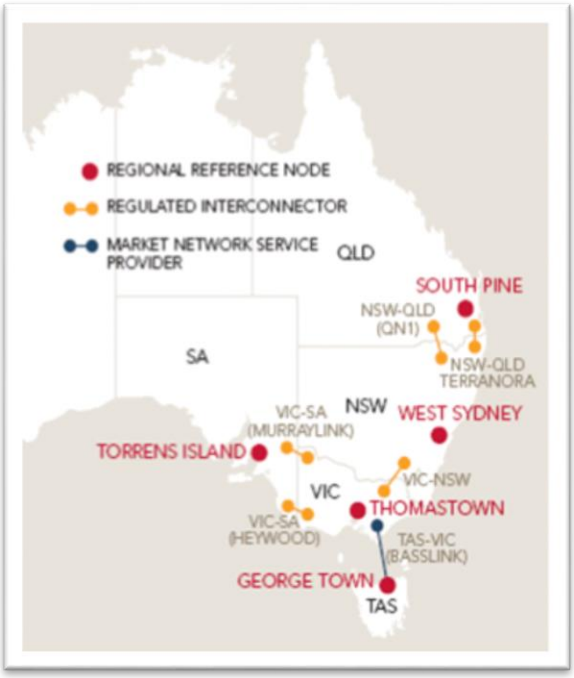
(c) Victoria;

(d) South Australia; and

(e) Tasmania.

16. Each *region* is connected to its adjacent *regions* by *interconnectors*, which are a series of *transmission lines* that facilitate the flow of electricity between *regions*. Figure 2 shows the *interconnectors*:

Figure 2 – Interconnectors in the NEM



17. A number of different types of organisations can participate in the *NEM*. These are called *Registered Participants*. Some are registered in their capacity as providers of infrastructure, such as *Network Service Providers* (**NSPs**) while others participate in the wholesale electricity exchange as *Market Participants*, buying and selling electricity.

18. The *Rules* allow producers of electricity in the *NEM* to register in a number of different categories. For example:

(a) *Scheduled Generators* participate in the *central dispatch* process. Generally, these are *Generators* with *generating units* whose *nameplate rating* is greater than 30 MW.

(b) *Non-Scheduled Generators* are typically *Generators* with *generating units* whose *nameplate rating* is less than 30 MW and do not participate in the *central dispatch* process.

(c) *Semi-Scheduled Generators* are *Generators* in respect of which a *generating unit* is classified as a *semi-scheduled generating unit*. Typically, this occurs where:

(i) a *generating unit* has a *nameplate rating* greater than 30 MW, or a group of generating units *connected* at a common *connection point* have a combined *nameplate rating* greater than 30 MW; and

(ii) the output of the relevant *generating unit* is *intermittent* (such as for wind farms).

(d) *Generators* that sell all of their electricity into the *spot market* are registered as *Market Generators*. *Market Generators* are paid the *spot price* applicable at their *network connection* for each *trading interval* during which they supply electricity to the *market*. A *Generator* that sells its entire output to either a *Local Retailer* or consumer located at the same *connection point* is classified as a *Non-Market Generator*.

E. The Regulatory Framework

19. The *NEM* is regulated by the National Electricity Law (**NEL**), a schedule to the *National Electricity (South Australia) Act 1996* (SA) that applies in each of the *participating jurisdictions* through a co-operative legislative scheme. The *Rules* are made and enforced under the NEL.

20. Under the NEL, AEMO has two core functions: power system operator, and wholesale market operator.

21. As *power system* operator, AEMO is concerned primarily with meeting standards of security and *reliability*. *Power system security* refers to the *power system's* capacity to continue operating within defined technical limits even in the event of the *disconnection* of a major *power system* element, such as an *interconnector* or large *generating unit*. *Power system reliability* refers to the *power system's* capacity to supply sufficient energy to meet consumer demand.

22. As wholesale *market* operator, AEMO facilitates the wholesale trading of electricity through a centrally co-ordinated *dispatch* process (*central dispatch*).

F. Central Dispatch

23. *Central dispatch* refers to the AEMO-managed process of *dispatching* electricity to meet demand in accordance with Chapter 3 of the *Rules*.

24. *Central dispatch* should aim to maximise the value of *spot market* trading on the basis of *dispatch offers* and *dispatch bids* (that is, the lowest cost *generating units* needed for electricity supply to meet demand are *dispatched*) subject to a number of matters, such as *network constraints* and *power system security* requirements.[5]

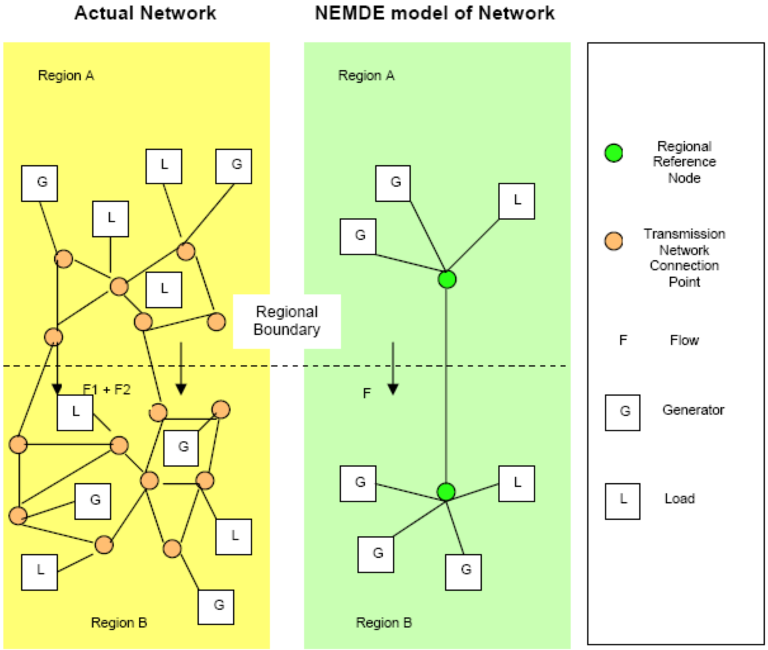
25. A *Generator* can own one or more *generating units*. Unless AEMO approves an application to aggregate these into a single entity for bidding purposes, AEMO receives bids for, and then determines loading levels (*dispatch instructions*) on an individual *generating unit* basis.

26. *Dispatch offers* are processed by a computer system called the National Electricity Market Dispatch Engine (**NEMDE**).

27. NEMDE is based on a constrained optimisation program that uses linear programming techniques that represent the *power system* as reflected in Figure 3:

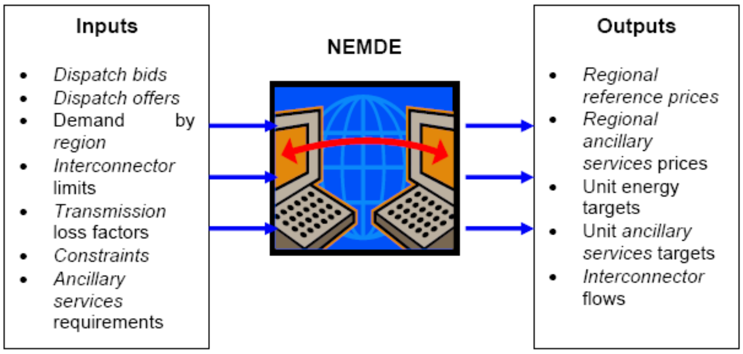
[5] Clause 3.8.1(b).

Figure 3 – How NEMDE Represents the Interconnected Network



28. AEMO forecasts electricity consumption in each *region*, identifies the capability of each *transmission network* to transmit electricity and captures the present state of the *power system* from information provided by *Transmission Network Service Providers* (**TNSPs**). AEMO then determines the *generation* outputs for each *Generator* according to an optimisation process that is specified in the *Rules* and, in practice, performed by NEMDE. This process is repeated for every *dispatch interval*. A simplified form of this optimisation process, as it applies at a general level, is depicted in Figure 4.

Figure 4 – NEMDE Optimisation Process



29. The *central dispatch* process attempts to maximise the value of electricity traded and produces a *dispatch price* in each *region* that represents the marginal price of producing the next increment of electricity at that location.

G. Scheduled Generation and Central Dispatch

30. To participate in *central dispatch*, *Scheduled Generators* must submit *dispatch offers* to AEMO to generate electricity[6]. In each *dispatch offer*, *Scheduled Generators* must make an offer to provide a certain number of megawatts (**MW**) of electricity for each of the 48 *trading intervals* in a *trading day* and may make offers for up to ten *price bands* for each *generating unit*.[7] All prices in *price bands* are locked in at 12:30 EST on the day before trading commences, but MW quantities associated with those *price bands* can be modified at any time prior to *dispatch*.

31. The highest price *Scheduled Generators* can offer is $14,000 per MWh (*market price cap*) and the lowest is -$1,000 per MWh (*market floor price*).[8] *Scheduled Generators* must specify other technical matters in their *dispatch offers*, such as their rate of change for increasing or decreasing their output in MW/minute (*ramp rate*).

32. AEMO sends *Scheduled Generators* a *pre-dispatch schedule* every 30 minutes. A *pre-dispatch schedule* is essentially a forecast that gives *Scheduled Generators* an indication of when they will be *dispatched*, and for what level of output they will be *dispatched* for the *trading intervals* in the next two days. *Scheduled Generators* have an opportunity to *rebid* the MW capacity that they can produce and other technical aspects of their capacity right up to five minutes before the event, but cannot change the prices for the *price bands* they have offered.

33. NEMDE sends *Scheduled Generators* electronic *dispatch instructions* to increase or reduce the quantity of electricity they produce for each *dispatch interval*.

34. NEMDE will process all the data it has available to achieve the lowest cost and most efficient outcome taking into account *power system* limitations. In general, and without considering the impact of *constraints*, *ramp rate* and other limitations for each *dispatch interval, Scheduled Generators* will be *dispatched* in ascending *price band* order until enough electricity has been produced to meet demand in that *dispatch interval*.

35. The *spot price* for a *trading interval* is the average of the six *dispatch interval* prices within that *trading interval*.

36. All of the *Scheduled Generators dispatched* during that *trading interval* will be paid the *spot price* times their *loss factor* for the energy they produced in that *trading interval*, even if their *dispatch offers* were for a lower price. Any *Scheduled Generators* whose offers were too expensive and were not needed to meet demand are not *dispatched* and, consequently, do not get paid. In this way, the wholesale exchange encourages competition between *Scheduled Generators*.

H. Semi-Scheduled Generation and Central Dispatch

37. A *Semi-Scheduled Generator* must operate a *semi-scheduled generating unit* in accordance with the *central dispatch* process under Chapter 3 of the *Rules*.[9]

38. The *Rules* distinguish between two different forms of *dispatch interval* for *semi-scheduled generating units,* which are treated differently in the *central dispatch* process:

    (a) *semi-dispatch intervals*; and

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[6] Clause 3.8.2(a).
[7] Clause 3.8.6(a).
[8] Clauses 3.9.4(b) and 3.9.6(b).
[9] Clause 2.2.7(h).

(b) *dispatch intervals* that are not *semi-dispatch intervals*.

39. Under the *Rules*, a *semi-dispatch interval* is a *dispatch interval* for which either:

(a) a *network constraint* would be violated if the *semi-scheduled generating unit*'s *generation* were to exceed the *dispatch level* specified in the related *dispatch instruction* at the end of the *dispatch interval*; or

(b) the *dispatch level* specified in a *dispatch instruction* is less than the *unconstrained intermittent generation forecast* (**UIGF**) at the end of the *dispatch interval*,

and which is notified by AEMO in a *dispatch instruction* to be a *semi-dispatch interval*.

40. *Semi-Scheduled Generators* participate in the *central dispatch* process by submitting offers, but effectively operate as though they were *Non-Scheduled Generators* (and need not respond to *dispatch instructions*) unless AEMO declares a *semi-dispatch interval* for a *semi-scheduled generating unit*. During a *semi-dispatch interval,* the output for that *semi-scheduled generating unit* must not exceed a *dispatch level* specified by NEMDE.

41. In operating the *central dispatch* process under clause 3.8 of the *Rules*, AEMO's obligation in clause 3.8.1(b) to aim to maximise the value of *spot market trading* is subject to a number of matters, including, *non-scheduled load* requirements in each *region*[10] and, in respect of *semi-scheduled generating units*, *constraints* identified by the UIGF.[11]

42. The requirement for AEMO to develop a UIGF is established in clause 3.7B of the *Rules*, which provides that AEMO must prepare a forecast of the *available capacity* of each *semi-scheduled generating unit* (to be known as the UIGF) for the purposes of, amongst other things, *dispatch*.[12]

43. In preparing a UIGF under clause 3.7B, AEMO must take into account the following matters:[13]

(a) the maximum *generation* of the *semi-scheduled generating unit* provided by the *Semi-Scheduled Generator* as part of its *bid and offer validation data*;[14]

(b) the *plant availability* of the *semi-scheduled generating unit* submitted by the *Semi-Scheduled Generator* under clause 3.7B(b);

(c) the information obtained for the *semi-scheduled generating unit* from the *remote monitoring equipment* in clause S5.2.6.1;

(d) the forecasts of the energy available for input into the electrical power conversion process for each *semi-scheduled generating unit*;

(e) the *energy conversion model* for each *semi-scheduled generating unit*;

(f) the assumption that there are no *network constraints* otherwise affecting the *generation* from that *semi-scheduled generating unit*; and

(g) the timeframes of, amongst other things, *dispatch.*

44. A UIGF should, therefore, forecast the total electrical *power* output from available *semi-scheduled generating uni*ts, based solely on the forecast *power* input to its

[10] Clause 3.8.1(b)(3).
[11] Clause 3.8.1(b)(2)(ii).
[12] Clause 3.7B(a)(2).
[13] Rule 3.7B(c).
[14] Rule 3.7B(c)(1), which was inserted in version 42 of the Rules, effective from 24 March 2011.

intermittent energy conversion process and ignoring any *constraints* on its electrical *power* output, such as *network* limitations.

45. The data that is used to produce *dispatch instructions* for *semi-scheduled generation* is processed by a number of systems. The UIGF data for wind generators is determined by the Australian Wind Energy Forecasting System (**AWEFS**) and for solar generators by the Australian Solar Energy Forecasting System (**ASEFS**).

46. The manner in which AEMO *dispatches semi-scheduled generating units,* and its use of AWEFS and ASEFS in preparing a UIGF is set out in AEMO's 'Dispatch' procedure, which is a *power system operating procedure* for the purposes of clause 4.10 (**Dispatch Procedure**) of the *Rules*.[15]

47. The Dispatch Procedure provides that specified SCADA inputs are to be used by AWEFS in preparing a UIGF. Version 72 of the Dispatch Procedure applied at the commencement of the Scheduling Error Period and version 81 applied at the end. Attachment 3, dealing with the *dispatch* of *semi-scheduled generation*, was substantially amended in version 79, which applied from 30 May 2014, to include the SCADA data requirements for ASEFS and to expand on the range of SCADA data required by AWEFS.[16]

I. The Scheduling Errors

48. Clause 3.8.24(a) of the *Rules* provides that a *scheduling error* is any one of the following circumstances:

    (a) the DRP determines under clause 8.2 that AEMO has failed to follow the *central dispatch* process set out in clause 3.8;[17]

    (b) AEMO declares that it failed to follow the *central dispatch* process set out in clause 3.8;[18] or

    (c) AEMO determines under clause 3.9.2B(d) that a *dispatch interval* contained a manifestly incorrect input.[19]

49. In February 2016, AEMO declared that it failed to follow the *central dispatch* process by:

    (a) producing UIGFs that did not reflect each Generating System's available capacity, causing some Generating Systems' *dispatch levels* to oscillate and, in some cases, reduce to zero (**Scheduling Error 1**); and

    (b) failing to accept the UIGFs produced by AWEFS or ASEFS (as applicable) in NEMDE because the nominated dispatch quantities were greater than each relevant Generating System's *nameplate rating* and limiting their output to their *nameplate rating*, which was less than their *generation* capacity (**Scheduling Error 2**).

50. AEMO has *published* a report titled 'Scheduling Error Report – AWEFS and ASEFS Unconstrained Intermittent Generation Forecast (UIGF) Scheduling Errors – 2012-

[15] Current version available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/2016/SO_OP_3705---Dispatch.pdf
[16] The *dispatch* of *semi-scheduled generation* is now covered in Appendix C.
[17] Clause 3.8.24(a)(1).
[18] Clause 3.8.24(a)(2).
[19] Clause 3.8.24(a)(3).

2016' (**Report**).[20] The Report describes the occurrence of the *scheduling errors* and a copy is provided in **Schedule 4**.

J. Dispatch Intervals affected by each Scheduling Error

51. In its Report, AEMO confirms that:

    (a) Scheduling Error 1 affected the output from a number of *Market Generators* during a number of *dispatch intervals* between 0215 hr on 14 March 2012 and 1800 hr on 7 April 2016; and

    (b) Scheduling Error 2 affected the output from a number of *Market Generators* during a number of *dispatch intervals* between 0445 hr on 30 June 2012 and 1120 hr on 24 March 2016.

K. 2012 UIGF Scheduling Error

52. As detailed in section 5 of the Report, a number of *Market Generators* received compensation in respect of a *scheduling error* declared by AEMO in June 2012 (**2012 Scheduling Error**), which resulted in AWEFS not being able to detect *semi-dispatch intervals* and, consequently, calculate the UIGF correctly.

53. While the underlying issue that gave rise to the *scheduling error* was resolved in 2013, it did not fully resolve the problem of AWEFS not being able to detect *semi-dispatch intervals* every time it should have.

54. Consequently, AEMO has approached the calculation of compensation differently for *Market Generators* who received compensation as a result of the 2012 Scheduling Error and those who didn't.

55. Appendix D of the Report details the start dates from which AEMO has calculated the impact of Scheduling Error 1 and Scheduling Error 2.

L. Calculation of Compensation

56. Clause 3.16.2 of the *Rules* provides that where a *scheduling error* occurs:

    (a) a *Market Participant* may apply to the DRP for a determination as to compensation;[21] and

    (b) the DRP may determine that compensation is payable to *Market Participants* and the amount of any such compensation payable from the *Participant compensation fund*.[22]

57. A *Scheduled Generator* or *Semi-Scheduled Generator* who receives an instruction in respect of a *scheduled generating unit* or *semi-scheduled generating unit* (as applicable) to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling errors* not occur is entitled to receive in compensation an amount determined by the DRP.[23]

58. The DRP must, therefore, determine the compensation payable in respect of any *scheduled generating unit* or *semi-scheduled generating unit* that, as a result of the

[20] The Report was *republished* in December 2016 after a number of matters leading to the *scheduling errors* were resolved.
[21] Clause 3.16.2(a).
[22] Clause 3.16.2(b).
[23] Clause 3.16.2(d).

scheduling errors, was *dispatched* at a lower level than it would have been had the *scheduling errors* not occur.[24]

59. To determine the amount of compensation payable to each Claimant, it is necessary to establish the following values for each affected *dispatch interval* and *semi-dispatch interval*:

    (a) the actual output of each Generating System;

    (b) the *dispatch instruction* that would have been issued by AEMO in the absence of the *scheduling errors*;

    (c) the applicable *intra-regional loss factor* for each Generating System; and

    (d) the applicable *spot price*.[25]

60. The calculation of losses affecting *Semi-Scheduled Generators* also requires AEMO to identify affected *semi-dispatch intervals*. AEMO's assumptions and methodology in identifying affected *semi-dispatch intervals* arising out of Scheduling Error 1 and Scheduling Error 2 are detailed in Appendix E and F of the Report, respectively.

61. The following compensation principles have been agreed by the parties for the purposes of quantifying each Claimant's *spot market* losses:

    (a) Calculate the difference (in MWh) between the actual output of a *generating unit* and the output that would have occurred in the absence of the *scheduling error*;

    (b) Multiply the quantity calculated in accordance with paragraph (a) by the *intra-regional loss factor* to give the compensable quantity (in MWh).

    (c) The *spot market* loss is the compensable quantity calculated in accordance with paragraph (b) multiplied by the applicable *spot price*.

    (d) If the applicable *spot price* for an affected *dispatch interval* or *semi-dispatch interval* is negative, the calculation in accordance with paragraph (c) will result in a payment to the *market* (that is, a credit).

62. Further details of AEMO's assumptions and methodology in calculating the *constrained-off energy* for *Scheduled Generators* and *Semi-Scheduled Generators* is detailed in Appendix G of the Report.

M. Compensation Amounts

63. AEMO has calculated the amount of compensation that would be payable to each Claimant, based on the principles and methodology referred to in Part L.

64. The calculations are agreed by each Claimant. The total compensation due to each Claimant are set out below:

Claimant	Compensation
AGL Hydro Partnership	$ 1,765,722.30
Lake Bonney Wind Power Pty Ltd	$ 883,153.25
Hydro-Electric Corporation (trading as Hydro Tasmania)	$ 167,585.65
Mt Mercer Windfarm Pty Ltd	$ 162,722.01
Boco Rock Wind Farm Pty Ltd	$ 70,988.34

[24] Clause 3.16.2(d)

[25] Clause 3.16.2(h)(3) requires the *dispute resolution panel* to use the *spot price* determined under Clause 3.9 in determining compensation.

Claimant	Compensation
Pacific Hydro Clemens Gap Pty Ltd	$ 46,464.31
AGL SA Generation Pty Limited	$ 36,944.04
Woodlawn Wind Pty Ltd	$ 30,881.77
Gunning Wind Energy Developments Pty Ltd	$ 28,520.96
Origin Energy Electricity Limited	$ 14,148.64
CS Energy	$ 11,722.31
AGL Macquarie Pty Limited	$ 9,269.41
Stanwell Corporation Limited	$ 7,682.52
EnergyAustralia Pty Ltd	$ 7,642.83
Taralga Wind Farm Nominees No 2 Pty Ltd	$ 3,113.38
AGL Loy Yang Marketing Pty Ltd	$ 2,676.58
Origin Energy Uranquinty Power Pty Ltd	$ 426.51
EnergyAustralia Yallourn Pty Ltd	$ 156.69

N. Participant Compensation Fund

65. AEMO is required by clause 3.16.1 of the *Rules* to 'maintain, in the books of the corporation, a fund called the *Participant compensation fund* for the purpose of paying compensation ... as determined by the *dispute resolution panel* for *scheduling errors*…'.

66. AEMO is required to pay to the *Participant compensation fund* the component of *Participant fees* attributable to the *Participant compensation fund*. The overall funding requirement for each financial year is the lesser of:

(a) $1,000,000; and

(b) $5,000,000 minus the amount that AEMO reasonably estimates will be the balance of the *Participant compensation fund* at the end of the *financial year*.[26]

67. Any interest paid on money held in the *Participant compensation fund* also accrues to and forms part of the *Participant compensation fund*.[27]

Participant Fee Determination

68. AEMO must prepare and *publish* before the beginning of each *financial year* a budget of the revenue requirements for AEMO for that *financial year*.[28] The budget must take into account and separately identify projected revenue requirements in respect of the funding requirements of the *Participant compensation fund* in accordance with clause 3.16.[29] The projected revenue requirements in respect of the funding requirements of the *Participant compensation fund* must only be recovered from *Scheduled Generators*, *Semi-Scheduled Generators* and *Scheduled Network Services Providers*.[30]

69. AEMO must also develop, review and *publish* the structure (including the introduction and determination) of *Participant fees* for such periods as AEMO considers

[26] See clause 3.16.1(c).
[27] Clause 3.16.1(e).
[28] Clause 2.11.3(a).
[29] Clause 2.11.3(b)(8).
[30] Clause 2.11.3(b)(8).

appropriate.[31] The *Participant fees* should recover the budgeted revenue requirements for AEMO determined under clause 2.11.3.[32]

70. AEMO has determined the structure of *Participant fees* for the period 1 July 2016 to 30 June 2021.[33] AEMO determined that the budgeted revenue requirements in respect of the *Participant compensation fund* will be allocated to *Scheduled Generators, Semi-Scheduled Generators* and *Scheduled Network Service Providers* and levied using a combination of historical capacity and historical energy scheduled, where:

    (a) 50% will be collected on the basis of MWh of energy scheduled or *metered* in the previous calendar year; and

    (b) 50% will be collected on the basis of the higher of the greatest registered capacity and highest notified maximum capacity in the previous calendar year.

71. AEMO may charge a *Registered Participant* the relevant components of *Participant fees* by giving the *Registered Participant* a statement setting out the amount payable by that *Registered Participant* and the date for payment.[34] In the case of *Market Participants*, AEMO may, alternatively, include the relevant amount in the f*inal statements* described in clause 3.15.15.[35] A *Registered Participant* must pay to AEMO the net amount stated in the relevant statement by the date specified by AEMO.[36]

Matters to be taken into account by DRP

72. The *Participant compensation fund* balance as at 15 March 2017 is $5,115,450.

73. As a consequence, the funding requirement for the *Participant compensation fund* is nil until 30 June 2017.

74. Since the commencement of the *market* there have been 29 payments made from the *Participant compensation fund*. These are as follows:

Market Participant	Date of Scheduling Error	Compensation
Snowy Hydro Limited	31 Oct 2005	$438,892.00
Macquarie Generation	22 Oct 2007	$4,544,638.00
AGL Hydro Partnership	19 & 20 Nov 2009	$571,935.06
Synergen Power Pty Ltd	19 May 2009 - 14 Jan 2010	$246,858.78
AGL Hydro Partnership Infigen Trustpower Pacific Hydro EnergyAustralia	Various	$78,585.00 $1,178,290.00 $12,031.00 $29,999.00 $11,891.00
Hydro-Electric Corporation (trading as Hydro Tasmania) AGL Loy Yang Marketing Pty Ltd CS Energy Limited AGL Hydro Partnership Origin Energy Electricity Limited AGL Macquarie Pty Limited Callide Power Trading Pty Limited	2 May 2014 - 6 Jun 2014	$296,661.14 (in total)

[31] Clause 2.11.1(a).
[32] Clause 2.11.1(b)(2).
[33] See http://www.aemo.com.au/Datasource/Archives/Archive595.
[34] Clause 2.11.2(a).
[35] Clause 2.11.2(b).
[36] Clause 2.11.2(c).

Market Participant	Date of Scheduling Error	Compensation
AGL SA Generation Pty Limited		
Delta Electricity		
Snowy Hydro Limited		
Stanwell Corporation Limited		
Hazelwood Power		
EnergyAustralia Pty Ltd		
Aurora Energy (Tamar Valley) Pty Ltd (trading as AETV Power)		
Flinders Operating Services Pty Ltd		
EnergyAustralia Yallourn Pty Ltd		
IPM Australia Limited		
Braemar Power Project Pty Ltd		
Origin Energy Uranquinty Power Pty Ltd		
Pelican Point Power Limited		

O. Other Applications for Compensation

75. No further *scheduling errors* have been declared since the last payment.

76. There are three other outstanding claims for compensation in respect of three separate *scheduling errors*:

(a) The first was declared by AEMO as a result of the application of incorrect ratings to three 66kV *transmission lines* in Victoria, which were then used in *constraint* equations that were subsequently used in *central dispatch*. If all submitted claims are accepted by the DRP, the total to be paid is $5,554,203.90.

(b) The second was declared by AEMO as a result of the application of incorrect directional ratings to manage the flow on the two *transformers* at South East Substation in South Australia. If all submitted claims are accepted by the DRP, the total paid to the claimants will be $221,890.52.

(c) The third was declared by AEMO as a result of the application of incorrect SCADA readings from Feeder 7145 in Queensland, which was then used in *constraint* equations that were subsequently used in *central dispatch*. If all submitted claims are accepted by the DRP, the total paid to the claimants will be $178,505.43.

77. Taking all claims into consideration, the total amount to be paid out of the *Participant compensation fund* in the current *financial year* will exceed the total amount currently deposited in it.

78. In making its determination, the DRP must:

(a) consider the claim for compensation by reference to the reduction in the *loading level* at which a *generating unit* operated due to the *scheduling error*; [37]

(b) use the *spot price* determined under clause 3.9;[38]

(c) take into account the current balance of the *Participant compensation fund* and the potential for further liabilities to arise during the year;[39] and

(d) recognise that the aggregate liability in any year in respect of *scheduling errors* cannot exceed the balance of the *Participant compensation fund* that would

[37] Clause 3.16.2(d).
[38] Clause 3.16.2(h)(3).
[39] Clause 3.16.2(h)(4).

have been available at the end of the year if no compensation payments for *scheduling errors* had been made during that year.[40]

79. In a decision of the DRP dated 24 April 2008 in a claim for compensation from the *Participant compensation fund* by Macquarie Generation, it was held that the reference to 'the potential for further liabilities to arise during the year' in clause 3.16.2(h)(4) is a reference to 'the possibilities of further actual liabilities during the financial year' that will have created a clear balance in the *Participant compensation fund*.[41] The DRP also accepted that the reference to 'year' in clause 3.16.2(h) is a reference to a *financial year*.[42]

80. In a decision of the DRP dated 9 November 2016, the DRP described the further liabilities referenced in clause 3.16.2(h)(4) as 'future contingent liabilities'. Specifically in reference to a claim for compensation for losses arising from the AWEFS scheduling error, the DRP commented that the impending claim had been advised to the WEMDRA and was well known to the market. The DRP stated: 'it is more likely than not that the wind scheduling error matter will result in a liability to be met by the Participant compensation fund; and while the timing is unclear the liability may crystallise before 30 June 2017'.[43]

P. The Need for Apportionment

81. There are insufficient funds in the *Participant compensation fund* to cover all current claims for compensation, let alone any prospective claim.

82. Full payment of the loss of the Claimants should not be made, as this would defeat all other known claims for compensation that would be payable by the end of the current *financial year*.

83. A more equitable distribution of the balance of funds in the *Participant compensation fund* is necessary so as not to defeat the spirit of clause 3.16.2(h) of the *Rules*.

84. The DRP must consider how to allocate available funds.

85. Most of the case law around the distribution of limited funds to claimants with claims that, in total, exceed the balance of available funds are in the areas of insolvency,[44] or breach of trust[45], but only a limited sub-set of these would appear to have any application in the present circumstances.

86. Of these, the parties submit that the most appropriate approach is allocation on a pari passu, or on a pro rata basis – the advantage of this type of allocation is that each Claimant receives some compensation based on the following formula:

$$C * \frac{B}{S}$$

Where: C = the amount of compensation sought by a claimant

B = the balance in the *Participant compensation fund*

S = Sum of all amounts of compensation sought by all claimants

[40] Clause 3.16.2(h)(5).
[41] See paragraphs 24 and 25 of the decision.
[42] See paragraph 15 of the decision.
[43] See paragraph 41 of the decision.
[44] See for example, *Australian Securities and Investments Commission v Letten* (No7) [2010] FCA 1231.
[45] See for example, *Hannan v Zindilis* [2016] VSC 723.

87. Australian case law suggests that the pari passu rule is the preferred mode of allocating funds.[46]

Q. Costs

88. For the purposes of this claim, the costs of these proceedings (other than the legal costs of the parties) will be as agreed between the Claimants and summarised by the *Adviser*. Each party will bear its own legal costs.

DATED: 21 March 2017

[46] See *Hannan v Zindilis* [2016] VSC 723, at paragraph 25.

SCHEDULE 1 - CLAIMANTS

Affected Generator	ABN	Affected Generating System	Classification	DUID
AGL Hydro Partnership	86 076 691 481	The Bluff Wind Farm	Semi-Scheduled	BLUFF1
		Broken Hill Solar Plant	Semi-Scheduled	BROKENH1
		Dartmouth Power Station	Scheduled	DARTM1
		Eildon Power Station	Scheduled	EILDON1 & EILDON2
		Hallett 1 Wind Farm	Semi-Scheduled	HALLWF1
		Hallett 2 Wind Farm	Semi-Scheduled	HALLWF2
		Macarthur Wind Farm	Semi-Scheduled	MACARTH1
		Bogong/Mckay Power Station	Scheduled	MCKAY1
		North Brown Hill Wind Farm	Semi-Scheduled	NBHWF1
		Nyngan Solar Plant	Scheduled	NYNGAN1
		Oaklands Hill Wind Farm	Semi-Scheduled	OAKLAND1
		Somerton Power Station	Scheduled	AGLSOM
		Townsville Gas Turbine	Scheduled	YABULU & YABULU2
		West Kiewa Power Station	Scheduled	WKIEWA1 & WKIEWA2
AGL Loy Yang Marketing Pty Ltd	19 105 758 316	Loy Yang A Power Station	Scheduled	LYA1, LYA2, LYA3 & LYA4
AGL Macquarie Pty Ltd	18 167 859 494	Bayswater Power Station	Scheduled	BW01, BW02, BW03 & BW04
		Liddell Power Station	Scheduled	LD01, LD02, LD03 & LD04
AGL SA Generation Pty Ltd	84 081 074 204	Torrens Island Power Station "A"	Scheduled	TORRA1, TORRA2, TORRA3, TORRA4
		Torrens Island Power Station "B"	Scheduled	TORRB1, TORRB2, TORRB3 & TORRB4
Boco Rock Wind Farm Pty Ltd	49 137 886 750	Boco Rock Wind Farm	Semi-Scheduled	BOCORWF1
CS Energy Limited	54 078 848 745	Callide B Power Station	Scheduled	CALL_B_1 & CALL_B_2
		Gladstone Power Station	Scheduled	GSTONE1, GSTONE2, GSTONE3, GSTONE4, GSTONE5, GSTONE6
		Kogan Creek Power Station	Scheduled	KPP_1
		Wivenhoe Power Station	Scheduled	W/HOE#2
EnergyAustralia Pty Ltd	99 086 014 968	Mt Piper Power Station	Scheduled	MP1
		Tallawarra Power Station	Scheduled	TALWA1
		Wallerawang Power Station	Scheduled	WW7 & WW8
		Hallett Power Station	Scheduled	AGLHAL
EnergyAustralia Yallourn Pty Ltd	47 065 325 224	Yallourn Power Station	Scheduled	YWPS1, YWPS2, YWPS3 & YWPS4
Gunning Wind Energy Developments Pty Ltd	28 145 164 478	Gunning Wind Farm	Semi-Scheduled	GUNNING1
Hydro-Electric Corporation (Trading as Hydro Tasmania)	48 072 377 158	Musselroe Wind Farm	Semi-Scheduled	MUSSELR1

Affected Generator	ABN	Affected Generating System	Classification	DUID
Lake Bonney Wind Power Pty Ltd	48 104 654 837	Lake Bonney Stage 2 Windfarm	Semi-Scheduled	LKBONNY2
		Lake Bonney Stage 3 Wind Farm	Semi-Scheduled	LKBONNY3
Mt Mercer Windfarm Pty Ltd	86 118 169 421	Mt Mercer Wind Farm	Semi-Scheduled	MERCER01
Origin Energy Electricity Limited	33 071 052 287	Eraring Power Station	Scheduled	ER01, ER02, ER03 & ER04
		Darling Downs Power Station	Scheduled	DDPS1
		Ladbroke Grove Power Station	Scheduled	LADBROK1 & LADBROK2
		Mortlake Power Station Units	Scheduled	MORTLK11 & MORTLK12
		Mt Stuart Power Station	Scheduled	MSTUART1, MSTUART2 & MSTUART3
		Osborne Power Station	Scheduled	OSB-AG
		Quarantine Power Station	Scheduled	QPS1, QPS2, QPS3, QPS4 & QPS5
Origin Energy Uranquinty Power Pty Ltd	26 120 384 938	Uranquinty Power Station	Scheduled	URANQ11, URANQ12, URANQ13 & URANQ14
Pacific Hydro Clements Gap Pty Ltd	87 109 911 097	Clements Gap Wind Farm	Semi-Scheduled	CLEMGPWF
Stanwell Corporation Limited	37 078 848 674	Barron Gorge Power Station	Scheduled	BARRON-1 & BARRON-2
		Stanwell Power Station	Scheduled	STAN-1, STAN-2, STAN-3 & STAN-4
		Swanbank E Gas Turbine	Scheduled	SWAN_E
		Tarong North Power Station	Scheduled	TNPS1
		Tarong Power Station	Scheduled	TARONG#1, TARONG#2, TARONG#3 & TARONG#4
		Kareeya Power Station	Scheduled	KAREEYA1, KAREEYA2, KAREEYA3 & KAREEYA4
Taralga Wind Farm Nominees No 2 Pty Ltd (ATF Taralga Wind Farm Operating Trust)	31 159 439 522	Taralga Wind Farm	Semi-Scheduled	TARALGA1
Woodlawn Wind Pty Ltd	38 139 165 610	Woodlawn Wind Farm	Semi-Scheduled	WOODLWN1

SCHEDULE 2 - GLOSSARY

TERM	MEANING
2012 Scheduling Error	See paragraph 52.
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
Dispatch Procedure	AEMO's 'Dispatch' procedure, SO_OP_3705.
DRP	*dispute resolution panel*
DUID	Dispatchable unit ID
EST	*Eastern Standard Time*
Generating Systems	See paragraph 3.
MW	megawatt
MWh	megawatt hour
NEL	*National Electricity Law*
NEMDE	*NEM* dispatch engine
NSP	*Network Service Provider*
Scheduling Error 1	See paragraph 49(a).
Scheduling Error 2	See paragraph 49(b).
Scheduling Error Period	See paragraph 4.
TNSP	*Transmission Network Service Provider*
UIGF	*unconstrained intermittent generation forecast*

SCHEDULE 3 - APPLICABLE VERSIONS OF THE RULES

Version	Start Date	End Date
49	5 April 2012	1 July 2012
50	2 July 2012	1 August 2012
51	2 August 2012	31 October 2012
52	1 November 2012	28 November 2012
53	29 November 2012	31 December 2012
54	1 January 2013	6 March 2013
55	7 March 2013	3 July 2013
56	4 July 2013	14 August 2013
57	15 August 2013	25 September 2013
58	26 September 2013	30 October 2013
59	31 October 2013	31 December 2013
60	1 January 2014	12 March 2014
61	13 March 2014	16 April 2014
62	17 April 2014	30 June 2014
63	1 July 2014	31 July 2014
64	1 August 2014	30 September 2014
65	1 October 2014	30 November 2014
66	1 December 2014	01 February 2015
67	2 February 2015	18 February 2015
68	19 February 2015	28 February 2015
69	1 March 2015	25 March 2015
70	26 March 2015	8 April 2015
71	9 April 2015	30 June 2015
72	1 July 2015	19 August 2015
73	20 August 2015	21 October 2015
74	22 October 2015	4 November 2015
75	5 November 2015	25 November 2015
76	26 November 2015	16 December 2015
77	17 December 2015	3 February 2016
78	4 February 2016	9 March 2016
79	10 March 2016	25 May 2016

SCHEDULE 4 - SCHEDULING ERROR REPORT

http://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Market_Event_Reports/2016/AWEFS-UIGF-Scheduling-error_2012-to-2016_Republished_FINAL.pdf