IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE
(Constituted for determinations as to compensation under clause 3.16.2 of the National Electricity Rules)

Applicants for compensation in relation to the *scheduling error* declared by *AEMO* in August 2015 in relation to 1 December 2014 to 13 January 2015 incorrect 66kV line ratings in Victoria **(Victorian matter):**

AGL Hydro Partnership (ABN 86 076 691 481) and others

(identified in Schedule 1 hereto)

Applicants for compensation in relation to the *scheduling error* declared by *AEMO* in November 2015 in relation to incorrect South East Transformer ratings in South Australia **(SA transformers matter):**

AGL Hydro Partnership (ABN 86 076 691 481) and others

(identified in Schedule 2 hereto)

Applicants for compensation in relation to energy losses from the *scheduling errors* declared by *AEMO* in February 2016 in relation to AWEFS Unconstrained Intermittent Generation Forecasts – 2012 to 2016 **(AWEFS matter):**

AGL Hydro Partnership (ABN 86 076 691 481)

AGL SA Generation Pty Ltd (ABN 84 081 074 204)

AGL Macquarie Pty Ltd (ABN 18 167 859 494)

AGL Loy Yang Marketing Pty Ltd (ABN 19 105 758 316)

Lake Bonney Wind Power Pty Ltd (ABN 48 104 654 837)

Woodlawn Wind Pty Ltd (ABN 38 139 165 610) and

Hydro-Electric Corporation trading as Hydro Tasmania (as the intermediary registered for Musselroe Wind Farm Pty Ltd) (ABN 48 072 377 158)

(together, the **AWEFS Alliance**)

and others (identified in Schedule 3 hereto)

Applicants for compensation in relation the *scheduling error* declared by *AEMO* in February 2017 in relation to 5 August 2016 to 17 August 2016 – incorrect SCADA for 7145 Feeder in Queensland **(Queensland matter):**

AGL Hydro Partnership (ABN 86 076 691 481) and others

(identified in Schedule 4 hereto)

and

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

DETERMINATION
(National Electricity Rules, clause 3.16.2)

In the Victorian matter, the Dispute Resolution Panel determines that:

1. Compensation is payable to each of the entities referred to in Schedule 1 hereto in respect of the *scheduling error* declared by *AEMO* in August 2015 in its report entitled “NEM scheduling error 1 December 2014 to 13 January 2014 – incorrect 66kV line ratings in Victoria” (the **Victorian *scheduling error***).

2. The following amounts of compensation (expressed exclusive of GST) are payable from the *Participant compensation fund* in respect of the revenue for the sale of electricity on the *spot market* that was lost by each entity by reason of the Victorian *scheduling error*:

Applicant	Compensation
Snowy Hydro Limited	$1,162,944.02
CS Energy Limited	$612,476.83
Stanwell Corporation Limited	$395,211.76
AGL SA Generation Pty Ltd	$169,778.18
Hydro-Electric Corporation (trading as Hydro Tasmania)	$94,567.13
Origin Energy Electricity Limited	$77,013.94
Callide Power Trading Pty Limited	$75,047.07
AGL Macquarie Pty Ltd	$73,640.02
EnergyAustralia Pty Ltd	$71,151.62
ERM Power Retail Pty Ltd	$53,521.84
Braemar Power Project Pty Ltd	$46,596.81
Pelican Point Power Limited	$46,392.81
Flinders Operating Services Pty Ltd	$46,032.19
Arrow Southern Generation Pty Ltd and Arrow Braemar 2 Pty Ltd	$40,218.34
Millmerran Energy Trader Pty Ltd	$31,307.08
AGL Hydro Partnership	$33,667.33
Synergen Power Pty Limited	$22,036.38
IPM Australia Limited	$12,993.79

AGL Loy Yang Marketing Pty Ltd	$9,048.90
EnergyAustralia Yallourn Pty Ltd	$5,966.73
Hazelwood Power	$5,806.04
Origin Energy Uranquinty Power Pty Ltd	$1,141.98
AETV Power	$243.58

In the SA transformers matter, the Dispute Resolution Panel determines that:

3. Compensation is payable to each of the entities referred to in Schedule 2 hereto in respect of the *scheduling error* declared by *AEMO* in November 2015 in its report entitled "NEM scheduling error – incorrect South East Transformer rating in South Australia", as updated in December 2016, (the **SA transformers *scheduling error***)

4. The following amounts of compensation (expressed exclusive of GST) are payable from the *Participant compensation fund* in respect of the revenue for the sale of electricity on the *spot market* that was lost by each entity by reason of the SA transformers *scheduling error*:

Applicant	**Compensation**
Snowy Hydro Limited	$28,215.23
AGL Macquarie Pty Ltd	$21,215.00
Callide Power Trading Pty Limited	$18,580.59
Origin Energy Electricity Limited	$13,387.14
Stanwell Corporation Limited	$8,419.89
Hydro-Electric Corporation (Trading as Hydro Tasmania)	$8,251.80
CS Energy Limited	$6,909.31
EnergyAustralia Pty Ltd	$6,700.48
Lake Bonney Wind Power Pty Ltd	$6,011.70
IPM Australia Limited	$2,707.73
AGL Loy Yang Marketing Pty Ltd	$765.99
EnergyAustralia Yallourn Pty Ltd	$558.58
Pelican Point Power Limited	$372.81
Milmerran Energy Trader Pty Ltd	$364.46
AGL Hydro Partnership	$338.07

Hazelwood Power	$286.56
AGL SA Generation Pty Ltd	$187.11
Origin Energy Uranquinty Power Pty Ltd	$45.42

In the AWEFS matter, the Dispute Resolution Panel determines that:

5. Compensation is payable to each of the entities referred to in Schedule 3 hereto in respect of the *scheduling errors* declared by *AEMO* in February 2016 in its "scheduling error report" entitled "AWEFS Unconstrained Intermittent Generation Forecast (UIGF) scheduling errors – 2012 to 2016", as updated in December 2016 (the **AWEFS *scheduling errors***).

6. The following amounts of compensation (expressed exclusive of GST) are payable from the *Participant compensation fund* in respect of the revenue for the sale of electricity on the *spot market* that was lost by each entity by reason of the AWEFS *scheduling errors*:

Applicant	**Compensation**
AGL Hydro Partnership	$981,317.83
Lake Bonney Wind Power Pty Ltd	$490,821.25
Hydro-Electric Corporation (trading as Hydro Tasmania)	$93,137.40
Mt Mercer Windfarm Pty Ltd	$90,434.38
Boco Rock Wind Farm Pty Ltd	$39,452.48
Pacific Hydro Clemens Gap Pty Ltd	$25,823.00
AGL SA Generation Pty Ltd	$20,532.02
Woodlawn Wind Pty Ltd	$17,162.85
Gunning Wind Energy Developments Pty Ltd	$15,850.81
Origin Energy Electricity Limited	$7,863.25
CS Energy Limited	$6,514.79
AGL Macquarie Pty Ltd	$5,151.57
Stanwell Corporation Limited	$4,269.64
EnergyAustralia Pty Ltd	$4,247.58

Taralga Wind Farm Nominees No 2 Pty Ltd	$1,730.29
AGL Loy Yang Marketing Pty Ltd	$1,487.54
Origin Energy Uranquinty Power Pty Ltd	$237.04
EnergyAustralia Yallourn Pty Ltd	$87.08

In the Queensland matter, the Dispute Resolution Panel determines that:

7. Compensation is payable to each of the entities referred to in Schedule 4 hereto in respect of the *scheduling error* declared by *AEMO* in February 2017 in its report entitled “NEM scheduling error 5 August 2016 to 17 August 2016 – incorrect SCADA for 7145 Feeder in Queensland” (the **Queensland *scheduling error***).

8. The following amounts of compensation (expressed exclusive of GST) are payable from the *Participant compensation fund* in respect of the revenue for the sale of electricity on the *spot market* that was lost by each entity by reason of the Queensland *scheduling error*:

Applicant	**Compensation**
CS Energy Limited	$63,420.80
Origin Energy Electricity Limited	$10,328.03
Hydro Electric Corporation (Hydro Tasmania)	$8,374.75
AGL SA Generation Pty Ltd	$6,034.58
Hazelwood Power	$5,665.55
AGL Macquarie Pty Ltd	$2,294.63
AGL Loy Yang Marketing Pty Ltd	$1,686.56
AGL Hydro Partnership	$1,157.81
Synergen Power Pty Limited	$144.84
AETV Power	$33.05
Origin Energy Uranquinty Power Pty Ltd	$28.03
Pelican Point Power Limited	$24.99
IPM Australia Limited	$12.57

In all four matters, the Dispute Resolution Panel determines by consent of the parties that:

9. The costs of the dispute resolution processes, comprising the costs of the *Adviser* and of the *DRP* (but excluding the legal costs of the parties), are to be borne by the applicants on a pro rata basis, whereby each applicant is to bear the proportion of those costs which corresponds to the ratio of that applicant's total compensation as determined under orders 2, 4, 6 and 8 above to $5,115,450.

10. For each applicant, *AEMO* is to deduct the amount referred to in order 9 from the total amount payable to that applicant pursuant to orders 2, 4, 6 and 8 above, and the balance is to be paid by *AEMO* to the applicant through Austraclear within 7 days of the date of this determination (together with any GST payable in respect of each such amount).

Date: 8 May 2017

Peter Gray

Peter R D Gray QC

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under professional standards legislation

Schedule 1 – applicants in Victorian matter

Applicant	ABN
AGL Hydro Partnership	86 076 691 481
AGL Loy Yang Marketing Pty Ltd	19 105 758 316
AGL Macquarie Pty Ltd	18 167 859 494
AGL SA Generation Pty Ltd	84 081 074 204
Arrow Southern Generation Pty Ltd And Arrow Braemar 2 Pty Ltd	27 245 692 985
Aurora Energy (Tamar Valley) Pty Ltd (Trading as AETV Power)	29 123 391 613
Braemar Power Project Pty Ltd	54 113 386 600
Callide Power Trading Pty Limited	80 082 468 719
CS Energy Limited	54 078 848 745
EnergyAustralia Pty Ltd	99 086 014 968
EnergyAustralia Yallourn Pty Ltd	47 065 325 224
ERM Power Retail Pty Ltd	87 126 175 460
Flinders Operating Services Pty Ltd	36 094 130 837
Hazelwood Power	40 924 759 557
Hydro-Electric Corporation (Trading as Hydro Tasmania)	48 072 377 158
IPM Australia Limited	87 055 563 785
Millmerran Energy Trader Pty Ltd	23 084 923 973
Origin Energy Electricity Limited	33 071 052 287
Origin Energy Uranquinty Power Pty Ltd	26 120 384 938
Pelican Point Power Limited	11 086 411 814
Snowy Hydro Limited	17 090 574 431
Stanwell Corporation Limited	37 078 848 674
Synergen Power Pty Limited	66 092 560 819

Schedule 2 – applicants in SA transformers matter

Applicant	ABN
AGL Hydro Partnership	86 076 691 481
AGL Loy Yang Marketing Pty Ltd	19 105 758 316
AGL Macquarie Pty Ltd	18 167 859 494
AGL SA Generation Pty Ltd	84 081 074 204
Callide Power Trading Pty Limited	80 082 468 719
CS Energy Limited	54 078 848 745
EnergyAustralia Pty Ltd	99 086 014 968
EnergyAustralia Yallourn Pty Ltd	47 065 325 224
Hazelwood Power	40 924 759 557
Hydro-Electric Corporation (Trading as Hydro Tasmania)	48 072 377 158
IPM Australia Limited	87 055 563 785
Lake Bonney Wind Power Pty Ltd	48 104 654 837
Millmerran Energy Trader Pty Ltd	23 084 923 973
Origin Energy Electricity Limited	33 071 052 287
Origin Energy Uranquinty Power Pty Ltd	26 120 384 938
Pelican Point Power Limited	11 086 411 814
Snowy Hydro Limited	17 090 574 431
Stanwell Corporation Limited	37 078 848 674

Schedule 3 – applicants in AWEFS matter

Applicant	ABN
AGL Hydro Partnership	86 076 691 481
AGL Loy Yang Marketing Pty Ltd	19 105 758 316
AGL Macquarie Pty Ltd	18 167 859 494
AGL SA Generation Pty Ltd	84 081 074 204
Boco Rock Wind Farm Pty Ltd	49 137 886 750
CS Energy Limited	54 078 848 745
EnergyAustralia Pty Ltd	99 086 014 968
EnergyAustralia Yallourn Pty Ltd	47 065 325 224
Gunning Wind Energy Developments Pty Ltd	28 145 164 478
Hydro-Electric Corporation (Trading as Hydro Tasmania)	48 072 377 158
Lake Bonney Wind Power Pty Ltd	48 104 654 837
Mt Mercer Windfarm Pty Ltd	86 118 169 421
Origin Energy Electricity Limited	33 071 052 287
Origin Energy Uranquinty Power Pty Ltd	26 120 384 938
Pacific Hydro Clements Gap Pty Ltd	87 109 911 097
Stanwell Corporation Limited	37 078 848 674
Taralga Wind Farm Nominees No 2 Pty Ltd (ATF Taralga Wind Farm Operating Trust)	31 159 439 522
Woodlawn Wind Pty Ltd	38 139 165 610

Schedule 4 – applicants in Queensland matter

Applicant	ABN
AGL Hydro Partnership	86 076 691 481
AGL Loy Yang Marketing Pty Ltd	19 105 758 316
AGL Macquarie Pty Ltd	18 167 859 494
AGL SA Generation Pty Ltd	84 081 074 204
Aurora Energy (Tamar Valley) Pty Ltd (Trading as AETV Power)	29 123 391 613
CS Energy Limited	54 078 848 745
Hazelwood Power	40 924 759 557
Hydro-Electric Corporation (Trading as Hydro Tasmania)	48 072 377 158
IPM Australia Limited	87 055 563 785
Origin Energy Electricity Limited	33 071 052 287
Origin Energy Uranquinty Power Pty Ltd	26 120 384 938
Pelican Point Power Limited	11 086 411 814
Synergen Power Pty Limited	66 092 560 819

REASONS FOR DETERMINATION
(National Electricity Rules, clause 3.16.2)

1. There are four matters before me, each of which involves multi-party applications for compensation pursuant to clause 3.16.2 of the National Electricity Rules (***Rules***)[1] in relation to *scheduling errors* payable from the *Participant compensation fund* established under clause 3.16.1 of the *Rules*.

The *scheduling errors* declared by *AEMO*

2. Relevantly, under clause 3.8.24(a)(2) of the *Rules*, a *scheduling error* occurs if *AEMO* declares that it failed to follow the *central dispatch* process set out in rule 3.8.

3. I am satisfied that *AEMO* has done so in relation to each of the four matters before me.

(1) The Victorian *scheduling error*

4. In August 2015, *AEMO* declared in its report entitled "NEM scheduling error 1 December 2014 to 13 January 2014 – incorrect 66kV line ratings in Victoria" that "a scheduling error has occurred because incorrect ratings were applied for three 66kV transmission lines connecting Ballarat and Horsham in Victoria" (page 4).

5. *AEMO* said later in its report (page 11), referring to clause 3.8.24(a)(2) of the *Rules*, that a *scheduling error* occurs when *AEMO* determines that it has failed to follow the *central dispatch* process set out in rule 3.8.

6. In the report (page 11), *AEMO* said that it:

> … has determined that its procedures for applying ratings in dispatch were not correctly followed and … declares that a scheduling error has occurred from 1 December 2014 to 13 January 2015.

7. The error in question arose as follows. On 1 August 2014 the relevant *TNSP*, Powercor, duly notified *AEMO* of changed winter and summer ratings for the three transmission lines. The summer ratings were for materially lower MVA values than the winter ratings, presumably because of the effect of anticipated ambient summer temperatures on the lines. Shortly afterwards, *AEMO* manually altered ("hand-dressed") the ratings for the three lines by setting the ratings for those lines to the newly notified winter ratings. *AEMO*, after a quality assurance review, also loaded the newly notified winter and summer ratings onto its EMS (Energy Management System) data base. However, when the time came for summer ratings to apply (on and from 1 December), the hand-dressed winter ratings continued to apply in the *network constraints* used in the *central dispatch* process, rather than the summer ratings that had been entered on the EMS data base. This error was not corrected until after the 09:05 *dispatch interval* on 13 January 2015, by which time (as *AEMO* later determined) market outcomes in 1,995 *dispatch intervals* had been affected, resulting in various *Generators* across all *regions* of the *NEM* having been

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[1] Italicised expressions in these reasons and the accompanying determination have the meanings defined in Chapter 10 of the *Rules*. Version 91 of the *Rules* is in force at the time of this determination. The *Rules* are made under Part 7 of the *National Electricity Law* and have the force of law in the jurisdictions relevant to these matters by reason of s 9 of *National Electricity Law* as applied in those jurisdictions by s 6 of the *National Electricity (South Australia) Act 1996* (SA), s 6 of the *National Electricity (Victoria) Act 2005* (Vic), and s 6 of the *Electricity – National Scheme (Queensland) Act 1997* (Qld).

constrained off in various of those *dispatch intervals*. AEMO conducted simulated reruns of the National Electricity Market Dispatch Engine (**NEMDE**) to calculate the amounts by which the outputs of the various *generating units* were affected.

8. In light of the above facts, and the declaration of a *scheduling error* in its report, *AEMO* was clearly of the view that its failure to apply the duly notified summer ratings for the three transmission lines, being a failure to follow its procedures for applying ratings to be applied in *dispatch*, constituted a failure to follow the *central dispatch* process set out in rule 3.8.

9. I think this view was open to *AEMO*.

10. In this regard, I note that clause 3.8.1 of the *Rules* relevantly provides that *AEMO* must operate a *central dispatch* process meeting the description in paragraph (a) of that clause, and that the *central dispatch* process "should aim to maximise the value of *spot market* trading" as described in that paragraph, "<u>subject to</u> … (5) *network constraints*".

11. Clause 3.8.10, entitled "Network constraints", relevantly (in paragraph (b)) requires *AEMO* to determine and represent *network constraints* in *dispatch* which may result from limitations on *intra-regional* or *inter-regional* power flows. These *network constraints* are to be formulated in accordance with *network constraint* formulation guidelines that *AEMO* must develop and *publish* in accordance with the *Rules consultation procedures*, which are to address such matters as the construction of *network constraint* equations and the circumstances under which changes will be made to them.

12. The applicable version of these guidelines is *AEMO's* "Constraint Formulation Guidelines" version 10.1, 10 December 2013. In those guidelines, section 6.2 deals with "How AEMO Receives Information", relevantly in the following terms:

> TNSPs are responsible for supplying AEMO with information on the limitations of their part of the transmission network. …
>
> Limit advice is most often supplied when there are changes to the capability of the power system …
>
> Upon receiving limit advice from TNSPs AEMO performs due diligence … to ensure that the advice is reasonable and that the power system remains in a stable operation state following the credible contingency indicated in the limit advice. Due diligence is a check only and is not used to recalculate the limit.

13. Section 7.1, entitled "General Formulation Principles" includes the following:

> Network constraint equations are used by AEMO to manage flows across one or more transmission elements (either transformers or transmission lines) by dispatching generation, loads or interconnectors in the energy market.
>
> As described in section 6.2 network service providers provide AEMO with limit equations and/or transmission element ratings. …

14. An implication that is available from these passages of the guidelines is that *AEMO* will, at least once it has performed the due diligence mentioned in section 6.2, implement a transmission element rating that has been provided by the relevant

Network Service Provider in accordance with the information provided by that *Network Service Provider*. This implication is consistent with AEMO's "Constraint Implementation Guidelines for the National Electricity Market" dated June 2015, pp 38-39, which also refers to seasonal rating timing changes.

15. Clause 3.8.10(d) provides:

> (d) *AEMO* must at all times comply with the *network constraint* formulation guidelines issued in accordance with paragraph (c).

16. Thus, on my reading of *AEMO's* report, *AEMO* has described an error that can reasonably be regarded as a failure to follow the *central dispatch* process set out in rule 3.8, and thus can reasonably be declared to be a *scheduling error*.

(2) The SA transformers *scheduling error*

17. In November 2015, *AEMO* declared in its report entitled "NEM scheduling error – incorrect south east transformer rating in South Australia", as updated in December 2016, that *AEMO* had determined that "a scheduling error has occurred because it applied incorrect directional ratings to manage flow on the No.1 and No.2 South East 275/132kV transformers in South Australia" an error that occurred in 5,192 *dispatch intervals* over 18 days, from *dispatch interval* 09:45 on 11 December 2014 to *dispatch interval* 10:20 on 29 December 2014 (page 5).

18. *AEMO* noted in its report (page 6), by reference to the criteria of clause 3.8.24(a)(2) of the *Rules*, that a *scheduling error* occurs when *AEMO* determines that it has failed to follow the *central dispatch* process set out in rule 3.8. On the same page, *AEMO* said that it:

> … has determined that its procedures for applying ratings in dispatch were not correctly followed and … declares that a scheduling error has occurred from DI 0945 hrs on 11 December 2014 to DI 1020 hrs on 29 December 2014.

19. The error in question arose as follows. On 1 September 2014 the relevant *TNSP*, Electranet, duly notified *AEMO* of new directional ratings for the transformers, with a load shed rating of 208MVA to apply when the power flow across them was from low to high and a lower rating, of 160MVA, to apply when power flows were from high to low. These new ratings were loaded into the EMS data base and duly implemented. However, an unrelated EMS data base loading on 11 December 2014 resulted in the directional ratings implemented in September 2014 no longer applying, and in a load shed rating of 160MVA applying for both high to low, and low to high, power flows. Thus the rating for low to high power flows across these transformers was 48MVA lower than the correct rating that had been notified by Electranet. This error was not corrected until after *dispatch interval* 10:20 on 29 December 2014, by which time (as *AEMO* later determined) market outcomes in 244 *dispatch intervals* had been affected, resulting in various *Generators* across all *regions* of the *NEM* having been *constrained off* in various of those *dispatch intervals*. AEMO conducted simulated reruns of NEMDE to calculate the amounts by which the outputs of the various *generating units* were affected.

20. In light of the above facts, and the declaration of a *scheduling error* in its report, *AEMO* was clearly of the view that its failure to apply the duly notified directional ratings for the transformers, being a failure to follow its procedures for applying ratings to be applied in *dispatch*, constituted a failure to follow the *central dispatch*

process set out in rule 3.8. For similar reasons to those outlined above in relation to the Victorian *scheduling error*, I think this view was open to *AEMO*. On my reading of *AEMO's* report, *AEMO* has described an error that can reasonably be regarded as a failure to follow the *central dispatch* process set out in rule 3.8, and thus can reasonably be declared to be a *scheduling error*.

(3)* The AWEFS *scheduling errors

21. In February 2016, *AEMO* declared in its "scheduling error report" entitled "AWEFS unconstrained intermittent generation forecast (UIGF) scheduling errors – 2012 to 2016", as updated in December 2016, that two *scheduling errors* had occurred "because the Australian Wind Energy Forecasting System (AWEFS) produced incorrect unconstrained intermittent generation forecasts (UIGFs) in some circumstances" (page 5), that is:

(a) "Scheduling Error 1", which *AEMO* described as follows:

> During consecutive semi-dispatch intervals, in some circumstances, the UIGFs produced by AWEFS or ASEFS were incorrect, being less than a wind or solar farm's generation capability based on prevailing wind or solar irradiance conditions. For such periods, the UIGFs used in the National Electricity Market Dispatch Engine (NEMDE) caused the Dispatch levels to oscillate and, in some cases, erode to zero.
>
> This scheduling error began at Dispatch Interval (DI) ending 0215 hrs on 14 March 2012 … and was resolved by DI ending 1800 hrs on 07 April 2016. All semi-scheduled wind farms and two solar farms, Broken Hill and Nyngan, in the National Electricity Market (NEM) were affected by this scheduling error.

(b) "Scheduling Error 2", which *AEMO* described as follows:

> When the UIGF produced by AWEFS or ASEFS for wind farms or solar farms exceeded their maximum capacity, the UIGF values were rejected by the UIGF validation logic within the central dispatch system. The wind farm's or solar farm's Initial MW was applied instead. When this occurred for semi–dispatch intervals, the Dispatch levels for the relevant wind farm or solar farm were less than its generation capability (after consideration of network constraints and other limitations) at the time.
>
> This scheduling error began at DI ending 0445 hrs on 30 June 2012 and was resolved by DI ending 1120 hrs on 24 March 2016. Oaklands Hill, Hallett Hill, Boco Rock and North Brown Hill Wind Farms, and Broken Hill Solar Farm were affected by this scheduling error.

22. Later in the report, *AEMO* identified the criteria in clause 3.8.24(a)(2) for declaring a *scheduling error* (page 9), that is, when *AEMO* determines it has failed to follow the *central dispatch* process set out in rule 3.8.

23. On 27 November 2012, a *DRP* determined a multi-party application for compensation from the *Participant compensation fund* relating to the UIGFs produced by AWEFS. The *DRP's* reasons for determination in that matter explain the general function of AWEFS and UIGFs in *central dispatch*.

24. As outlined in *AEMO's* report in February 2016, updated in December 2016 (page 6):

> Clause 3.7B(a) of the NER requires AEMO to prepare and make available at all times a UIGF of each semi-scheduled generating unit's available capacity. When preparing a UIGF, AEMO must take into account the real-time information provided by the semi-scheduled generating units in accordance with their energy conversion model and the assumption that no network constraints affect their generation.
>
> The UIGFs are then applied in the central dispatch process as an upper limit on each unit's Dispatch level (calculated by NEMDE), as required by clause 3.8.1 (b)(2)(ii) of the NER. For a semi–dispatch interval, the relevant generating unit must cap its output at, or below, this NEMDE-calculated Dispatch level by the end of the relevant dispatch interval (DI) if its semi–dispatch flag is also set for that DI. Otherwise the generating unit is free to operate at any level.

25. By reason of each of the two errors outlined in *AEMO's* report, *AEMO* formed the view that purported UIGF values, which were not the correct and applicable UIGFs meeting the requirements of rule 3.7B of the *Rules* for the relevant *Semi-Scheduled Generators,* were used in *central dispatch* in affected *semi-dispatch intervals*.

26. In those circumstances, it was open to *AEMO* to conclude that *scheduling errors* had occurred.

27. *AEMO* described the approach it took to assessing the energy market impact of the *scheduling errors* in the report, as follows (page 12):

> Following discussions with some affected Market Participants, AEMO was made aware of the potential for lost energy (MWh) not just in the affected DIs, but also in the subsequent DIs. To allow for compensation for lost energy in the subsequent DIs, AEMO also estimated lost MWh for one subsequent DI immediately following each affected DI.
>
> There were 45,730 DIs affected by Scheduling Errors 1 or 2. With one subsequent DI for each affected DI, the total number of affected and subsequent DIs increased to 65,423 DIs.
>
> AEMO conducted a simulated rerun of the NEMDE Dispatch files for the affected and subsequent intervals for Scheduling Errors 1 or 2 by replacing the original UIGF with the correct UIGF. …
>
> Based on the simulated rerun, total generation from semi-scheduled wind farms and solar farms was 86,492 MWh lower (constrained-off) due to Scheduling Errors 1 and 2.

28. In my view, this was a reasonable approach that was open to *AEMO*.

(4) The Queensland *scheduling error*

29. In February 2017, *AEMO* declared in its report entitled "NEM scheduling error 5 August 2016 to 17 August 2016 – incorrect SCADA for 7145 Feeder in Queensland" that "a scheduling error occurred from 05 August 2016 to 17 August 2016 because of incorrect Supervisory Control and Data Acquisition (SCADA) readings received for Feeder 7145 (Boyne Island – Calliope River 132 kV line) in Queensland" and that the incorrect data "resulted from a faulty transducer at the Boyne Island sub-station" (page 4).

30. *AEMO* explained in its report that the incorrect SCADA readings were used in a constraint equation used in *central dispatch* that bound in 409 *dispatch intervals*, resulting in *generation* being *constrained off* at various levels in all *regions* of the NEM (pages 6-9). AEMO conducted simulated reruns of NEMDE to calculate the amounts by which the outputs of the various *generating units* were affected.

31. *AEMO* noted (page 10 of the report):

> Under NER clause 3.8.24(a)(2), a scheduling error occurs when AEMO determines that it has failed to follow the central dispatch process set out in rule 3.8.
>
> In this case, incorrect SCADA inputs for the 7145 feeder resulted in incorrect representation of the flow on the feeder and unreasonably constrained-off generation.

32. Clause 3.8.1 of the *Rules* relevantly provides that *AEMO* must operate a *central dispatch* process "<u>subject to</u> … (inter alia) (5) *network constraints*".

33. In my view, in circumstances where *AEMO* had identified that incorrect SCADA inputs resulted in incorrect *network constraints* being identified, it was open to *AEMO* to conclude that a *scheduling error* had occurred.

Procedural steps

34. From early 2016 the *Adviser* received various communications and notices in relation to various of the matters now before me, and assisted in discussions to facilitate agreement between the affected *Market Participants* and *AEMO* as to the calculation of lost revenue attributable to *constrained off* or otherwise reduced *generation* resulting from the *scheduling errors* declared by *AEMO*, and related procedural issues. The procedural issues that arose were of some complexity, given that multiple *scheduling errors* fell to be considered at the same time, that so many *Market Participants* were affected, and that it appeared from an early stage that the aggregate of those losses would exceed the balance of the *Participant compensation fund*. It appears that, by late October 2016, those discussions had progressed to an advanced stage.

35. On 27 October 2016, Snowy Hydro Limited submitted to the *Adviser* an application for a determination as to compensation from the *Participant compensation fund* in relation to the Victorian *scheduling error*.

36. On 8 November 2016, the *Adviser* published a market notice to the effect that Snowy Hydro had applied for a determination as to compensation in relation to the Victorian *scheduling error*, that a compensation methodology had been agreed between Snowy Hydro and *AEMO*, that this *DRP* was established in the Victorian matter, and that there were at least two other *scheduling errors* that had been declared by *AEMO* for which *Market Participants* may be eligible for compensation from the *Participant compensation fund*, namely the SA transformers *scheduling error* and the AWEFS *scheduling errors*. I accepted the appointment as the *DRP* established in the Victorian matter on 9 November 2016.

37. The *Adviser* sought timely applications from any other *Market Participants* applying for determinations as to compensation in the Victorian matter, and a directions hearing was scheduled for 14 December 2016 before me as the *DRP* in the Victorian matter.

38. On 8 December 2016, the solicitor acting for the AWEFS Alliance foreshadowed that the AWEFS Alliance would seek determinations as to compensation for "energy losses" in relation to the AWEFS *scheduling error*, and sought leave to appear at the directions hearing in the Victorian matter, foreshadowing an application for a stay of the determination of the Victorian matter pending certain events.

39. I understand "energy losses" in this sense to be the energy (in MWh) attributable to the output of *generating units* being at lower levels than the levels to which they would otherwise have been *dispatched*, as a result of the relevant *scheduling errors*.

40. On 9 December 2016, the AWEFS Alliance applied for determinations as to compensation for lost revenue relating to energy losses in relation to the AWEFS *scheduling error*. In a covering letter dated 9 December 2016, the solicitor for the AWEFS Alliance said that:

> There is also the possibility of a claim for compensation being made by one or more of the Alliance members in respect of the impact of the AWEFS Scheduling Error on causer pays factors and associated regulation frequency control ancillary service cost allocations, but any such claim would be pursued separately to the energy losses claim.

41. At this point it should be noted that I have not received any claim for *frequency control ancillary service*-related losses from any member of the AWEFS Alliance, and so these reasons should not be read as addressing in any way issues such as whether such claims are compensable from the *Participant compensation fund*, whether such claims can be severed from claims for energy losses, and what may be the effect of reservation and deferral of *frequency control ancillary service*-related losses.

42. I was appointed as the *DRP* established for the AWEFS matter on 13 December 2016 and accepted that appointment on 14 December 2016.

43. On 14 December 2016, as *DRP* in the Victorian matter, I conducted the directions hearing in that matter, and amongst other things heard submissions as to joinder of additional applicants in the Victorian matter, foreshadowed that the future case management of the Victorian matter and the AWEFS matter would be in tandem, and foreshadowed procedural directions for the conduct of the matters. I also heard the AWEFS Alliance's submissions in support of their application for a stay of the determination of the Victorian matter, and Snowy Hydro's response, and reserved my decision on that application.

44. On 16 December 2016, I was appointed as the *DRP* established in the SA transformers matter, and accepted that appointment.

45. On 28 December 2016, I made procedural directions for the conduct of the three matters (the Victorian matter, the AWEFS matter and the SA transformers matter).

46. On 28 February 2017 I was appointed as the *DRP* established by the *Adviser* in the Queensland matter, and accepted that appointment.

47. The directions I had made in the matters before me on 28 December 2016 addressed issues of joinder of further applications by certain deadlines, made provision for submissions, and contemplated that there would be hearings as to the calculation of losses attributable to *constrained off* or otherwise reduced *generation*

resulting from the various *scheduling errors*, and then a hearing as to allocation of compensation from the available balance of the *Participant compensation fund*.

48. In the end, however, it was not necessary to conduct either of these hearings, and they were both vacated by further procedural directions. That is because the parties, with the assistance of the *Adviser*, reached agreement as to both the calculation of losses of revenue attributable to *constrained off* or otherwise reduced *generation* resulting from the *scheduling errors*, and as to a *pari-passu* allocation of the available balance of the *Participant compensation fund* to the losses so calculated. In connection with this settlement, on 8 March 2017, the AWEFS Alliance discontinued its application for a stay of the determination of the applications constituting the Victorian matter. The parties also reached an agreement as to the costs of the dispute resolution processes.

49. All concerned are to be commended, because the relevant issues were complex and the resolution of a contest on these issues would have consumed significant resources.

50. On 23 March 2017, I received access to four sets of joint submissions agreed between the parties in each of the matters before me, each dated 21 March 2017. They were updated on 12 April 2017. The joint submissions identify all the applicants to the matters, as now listed in the schedules to the accompanying determination. I am satisfied that each of the entities appearing in Schedule 1 to the determination is a party to the Victorian matter, each of the entities appearing in Schedule 2 is a party to the SA transformers matter, each of the entities appearing in Schedule 3 is a party to the AWEFS matter, and each of the entities appearing in Schedule 4 is a party to the Queensland matter, along with *AEMO*, which is a party to each of these matters. The joint submissions also identify the agreed loss calculation methodology in each matter, and the agreed loss calculations performed in relation to nearly all of the entities which are applying for determinations as to compensation. That methodology involves the ascertainment for each *generating unit* of energy (in MWh) attributable to the difference in its actual output compared with the level of output to which it would have been *dispatched* in the absence of the *scheduling error*, the adjustment of that amount of energy by then applicable *intra-regional loss factor*, and the application of the then-prevailing *spot price*.

51. I am satisfied that the settlement reached by the parties is a reasonable one that is open to them, and one that I can proceed to formalise by making determinations under clause 3.16.2 of the *Rules* conformably with the parties' arrangement.

52. From 13 April 2017, these reasons and the accompanying determinations were made available to the parties in draft form to ensure that the parties had no issues with the manner in which their settlement is to be implemented.

The task for the *DRP*

53. Clause 3.16.2 of the *Rules*, entitled "Dispute resolution panel to determine compensation", relevantly provides:

> (a) Where a *scheduling error* occurs, a *Market Participant* may apply to the *dispute resolution panel* for a determination as to compensation under this clause 3.16.2.
>
> (b) Where a *scheduling error* occurs, the *dispute resolution panel* may determine that compensation is payable to *Market Participants* and the amount of any such compensation payable from the *Participant compensation fund*.

(c) A determination by the *dispute resolution panel* as to compensation must be consistent with this clause 3.16.2.

(d) A *Scheduled Generator* or *Semi-Scheduled Generator* who receives an instruction in respect of a *scheduled generating unit* or *semi-scheduled generating unit* (as the case may be) to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occurred, will be entitled to receive in compensation an amount determined by the *dispute resolution panel*.

…

(h) In determining the level of compensation to which *Market Participants* are entitled in relation to a *scheduling error*, the *dispute resolution panel* must:

…

(3) Use the *spot price* as determined under rule 3.9, including any *spot prices* that have been adjusted in accordance with clause 3.9.2B;

(4) Take into account the current balance of the *Participant compensation fund* and the potential for further liabilities to arise during the year;

(5) Recognise that the aggregate liability in any year in respect of *scheduling errors* cannot exceed the balance of the *Participant compensation fund* that would have been available at the end of that year if no compensation payments for *scheduling errors* had been made during that year.

(i) The manner and timing of payments from the *Participant compensation fund* are to be determined by the *dispute resolution panel*.

54. Relevant provisions as to the costs of dispute resolution processes are to be found in Chapter 8 of the *Rules*. Clause 8.2.8 relevantly provides:

(a) The costs of any dispute resolution processes (other than legal costs of one or more parties), including the costs incurred by the *Adviser* in performing functions of the *Adviser* under clauses 8.2.5, 8.2.6A, 8.2.6B, 8.2.6C or 8.2.6D and the costs of the *DRP* and its members, are to be borne equally by the parties to the dispute unless:

(1) clause 8.2.8(b) applies; or

(2) otherwise agreed between the parties.

(b) Costs of the dispute resolution processes (including legal costs of one or more parties) may be allocated by the *DRP* for payment by one or more parties as part of any determination. Subject to clause 8.2.8(c), in deciding to allocate costs against one or more parties to a dispute, the *DRP* may have regard to any relevant matters, including (but not limited to) whether the conduct of that party or those parties unreasonably prolonged or escalated the dispute or otherwise increased the costs of the *DRP* proceedings.

55. The principal function of a *DRP* in a matter such as the present matters was recently outlined by a *DRP* (constituted by Mr Geoff Swier) in reasons for determination dated 9 November 2016 at [10]. That function is: *first,* to decide whether compensation is payable to the applicants (see clause 3.16.2(b) and (d)), *secondly*, if payable, the amount or "level" of that compensation (see clause 3.16.2(b), (d) and (h)), and *thirdly*, the manner and timing of any payments from the *Participant compensation fund* (see clause 3.16.2(i)).

56. Here, consistently with the parties' agreement that payment of compensation in respect of their agreed calculated losses is to be made *pari-passu* from the available balance of the *Participant compensation fund*, the parties have also agreed that the costs of the dispute resolution processes are to be borne pro rata by them, in proportion to the total amount of compensation to be paid to each applicant.

Compensation is payable

57. For the reasons outlined in paragraphs 2 to 33 above, I am satisfied that compensation is payable to each of the applicants specified in paragraphs 2, 4, 6 and 8 of the determination.

The quantum of compensation payable

58. As I have already mentioned, the parties' joint submissions identify an agreed loss calculation methodology in each matter, and the agreed loss calculations performed in accordance with that methodology in relation to the entities which are applying for determinations as to compensation. In each matter, I am satisfied that the agreed principles are logical and appropriately adapted to applying the principles in clause 3.16.2(d) and (h) to the circumstances of the matter.

59. In four tables set out below, I set out the amount of loss calculated by *AEMO* on the above principles, and agreed by each applicant. The total of all such figures across all matters is $9,204,421.35.

60. In February 2017, I was informed by *AEMO* that as at 15 March 2017, the balance of the *Participant compensation fund* would be $5,115,450. On this basis, and because I have not since been informed of anything to the contrary, I find that this is the amount of money currently available in the fund.

61. Adopting a uniform *pari-passu* discount factor across all matters and applicants, the discount factor to apply is therefore:

$5,115,450/$9,204,421.35 = 0.55576

62. In the third column of each of the tables below, I apply this discount factor to each loss calculation appearing in the corresponding row of the adjacent loss column.

63. In the Victorian matter, the following amounts of compensation are payable from the *Participant compensation fund*:

Applicant	**Loss**	**Compensation (0.55576 x loss)**
Snowy Hydro Limited	$ 2,092,529.19	$1,162,944.02
CS Energy Limited	$ 1,102,052.73	$612,476.83
Stanwell Corporation Limited	$ 711,119.47	$395,211.76
AGL SA Generation Pty Ltd	$ 305,488.31	$169,778.18
Hydro-Electric Corporation (trading as Hydro Tasmania)	$ 170,158.21	$94,567.13
Origin Energy Electricity Limited	$ 138,574.09	$77,013.94
Callide Power Trading Pty Limited	$ 135,035.03	$75,047.07
AGL Macquarie Pty Limited	$ 132,503.27	$73,640.02
EnergyAustralia Pty Ltd	$ 128,025.80	$71,151.62
ERM Power Retail Pty Ltd	$ 96,303.87	$53,521.84

Braemar Power Project Pty Ltd	$ 83,843.41	$46,596.81
Pelican Point Power Limited	$ 83,476.34	$46,392.81
Flinders Operating Services Pty Ltd	$ 82,827.47	$46,032.19
Arrow Southern Generation Pty Ltd and Arrow Braemar 2 Pty Ltd	$ 72,366.39	$40,218.34
Millmerran Energy Trader Pty Ltd	$ 56,332.02	$31,307.08
AGL Hydro Partnership	$ 60,578.90	$33,667.33
Synergen Power Pty Limited	$ 39,650.89	$22,036.38
IPM Australia Limited	$ 23,380.22	$12,993.79
AGL Loy Yang Marketing Pty Ltd	$ 16,282.03	$9,048.90
EnergyAustralia Yallourn Pty Ltd	$ 10,736.16	$5,966.73
Hazelwood Power	$ 10,447.02	$5,806.04
Origin Energy Uranquinty Power Pty Ltd	$ 2,054.80	$1,141.98
AETV Power	$ 438.28	$243.58
Totals	**$5,554,203.90**	**$3,086,804.37**

64. In the SA transformers matter, the following amounts of compensation are payable from the *Participant compensation fund*:

Claimant	**Loss**	**Compensation (0.55576 x loss)**
Snowy Hydro Limited	$ 50,768.74	$28,215.23
AGL Macquarie Pty Ltd	$ 38,172.96	$21,215.00
Callide Power Trading Pty Limited	$ 33,432.76	$18,580.59
Origin Energy Electricity Limited	$ 24,087.98	$13,387.14
Stanwell Corporation Limited	$ 15,150.22	$8,419.89
Hydro-Electric Corporation (Trading as Hydro Tasmania)	$ 14,847.77	$8,251.80
CS Energy Limited	$ 12,432.19	$6,909.31
EnergyAustralia Pty Ltd	$ 12,056.43	$6,700.48
Lake Bonney Wind Power Pty Ltd	$ 10,817.08	$6,011.70
IPM Australia Limited	$ 4,872.13	$2,707.73
AGL Loy Yang Marketing Pty Ltd	$ 1,378.27	$765.99
EnergyAustralia Yallourn Pty Ltd	$ 1,005.08	$558.58

Pelican Point Power Limited	$ 670.81	$372.81
Milmerran Energy Trader Pty Ltd	$ 655.79	$364.46
AGL Hydro Partnership	$ 608.30	$338.07
Hazelwood Power	$ 515.61	$286.56
AGL SA Generation Pty Ltd	$ 336.68	$187.11
Origin Energy Uranquinty Power Pty Ltd	$ 81.72	$45.42
Totals	**$221,890.52**	**$123,317.87**

65. In the AWEFS matter, the following amounts of compensation are payable from the *Participant compensation fund*:

Claimant	**Loss**	**Compensation (0.55576 x loss)**
AGL Hydro Partnership	$ 1,765,722.30	$981,317.83
Lake Bonney Wind Power Pty Ltd	$ 883,153.25	$490,821.25
Hydro-Electric Corporation (trading as Hydro Tasmania)	$ 167,585.65	$93,137.40
Mt Mercer Windfarm Pty Ltd	$ 162,722.01	$90,434.38
Boco Rock Wind Farm Pty Ltd	$ 70,988.34	$39,452.48
Pacific Hydro Clemens Gap Pty Ltd	$ 46,464.31	$25,823.00
AGL SA Generation Pty Ltd	$ 36,944.04	$20,532.02
Woodlawn Wind Pty Ltd	$ 30,881.77	$17,162.85
Gunning Wind Energy Developments Pty Ltd	$ 28,520.96	$15,850.81
Origin Energy Electricity Limited	$ 14,148.64	$7,863.25
CS Energy Limited	$ 11,722.31	$6,514.79
AGL Macquarie Pty Ltd	$ 9,269.41	$5,151.57
Stanwell Corporation Limited	$ 7,682.52	$4,269.64
EnergyAustralia Pty Ltd	$ 7,642.83	$4,247.58
Taralga Wind Farm Nominees No 2 Pty Ltd	$ 3,113.38	$1,730.29
AGL Loy Yang Marketing Pty Ltd	$ 2,676.58	$1,487.54
Origin Energy Uranquinty Power Pty Ltd	$ 426.51	$237.04

EnergyAustralia Yallourn Pty Ltd	$ 156.69	$87.08
Totals	**$3,249,821.50**	**$1,806,120.80**

66. In the Queensland matter, the following amounts of compensation are payable from the *Participant compensation fund*:

Claimant	**Loss**	**Compensation (0.55576 x loss)**
CS Energy Limited	$ 114,115.45	$63,420.80
Origin Energy Electricity Limited	$ 18,583.61	$10,328.03
Hydro Electric Corporation (Hydro Tasmania)	$ 15,069.00	$8,374.75
AGL SA Generation Pty Ltd	$ 10,858.24	$6,034.58
Hazelwood Power	$ 10,194.23	$5,665.55
AGL Macquarie Pty Ltd	$ 4,128.81	$2,294.63
AGL Loy Yang Marketing Pty Ltd	$ 3,034.70	$1,686.56
AGL Hydro Partnership	$ 2,083.30	$1,157.81
Synergen Power Pty Limited	$ 260.62	$144.84
AETV Power	$ 59.46	$33.05
Origin Energy Uranquinty Power Pty Ltd	$ 50.44	$28.03
Pelican Point Power Limited	$ 44.96	$24.99
IPM Australia Limited	$ 22.61	$12.57
Totals	**$178,505.43**	**$99,206.19**

67. I am not aware of any other “potential for further liabilities to arise during the year” within the meaning of clause 3.16.2(h)(4).

68. Applying clause 3.16.2(h) of the *Rules*, I am satisfied that the applicants are entitled to compensation in respect of the relevant *scheduling errors* at the levels and in the amounts specified in the right-hand column of the above tables.

Costs

69. As already mentioned, the allocation of the costs of the dispute resolution processes leading to and relating to the four matters have been agreed by the parties. Those costs are to be aggregated across all four matters and allocated to each entity pro rata by reference to the total compensation payable to that entity across all four matters.

70. I am also satisfied that I can and should make a determination, within my function of determining the manner and timing of payments from the *Participant compensation fund*, to permit *AEMO* to deduct the costs so allocated in respect of each entity from

the compensation that is payable to the entity by *AEMO* in accordance with the tables set out above.

Date: 8 May 2017

Peter Gray

Peter R D Gray QC

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