IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE
(Constituted for a determination under clause 3.16.2 of the National Electricity Rules)

Application for compensation in relation to the scheduling error on 1 May 2023 declared by AEMO on 21 June 2023

AGL Macquarie Pty Ltd (ABN 18 167 859 494) **Claimants**
AGL SA Generation Pty Ltd (ABN 84 081 074 204)
Snowy Hydro Limited (ABN 17 090 574 431)

DETERMINATION

The Dispute Resolution Panel determines that:

1. As a consequence of the scheduling error that occurred on 1 May 2023, each claimant is entitled to compensation out of the Participant Compensation Fund (the **Fund**), being the sum of:

   a. the amount set out for each claimant below (the **loss amount**); and:

AGL Macquarie Pty Limited	$59,177.03
AGL SA Generation Pty Limited	$3,082.24
Snowy Hydro Limited	$230,873.76

   b. a one-quarter share of the costs of the Dispute Resolution Panel (the **DRP**) and the Wholesale Market Dispute Resolution Panel (the **WEMDRA**), for each of AGL Macquarie and AGL SA Generation; and a one-half share of those costs for Snowy Hydro.

2. AEMO shall make payment, through Austraclear, to each claimant of the claimant's loss amount as set out in paragraph 1(a), within 20 business days of this Determination.

3. On behalf of the claimants, AEMO shall make payment out of the Fund to the DRP and the WEMDRA of the respective costs of the DRP and the WEMDRA, within 20 business days of receipt of a tax invoice from each of the DRP and the WEMDRA.

20 June 2024

Tom Clarke

IN THE DISPUTE RESOLUTION PANEL AT MELBOURNE
(Constituted for a determination under clause 3.16.2 of the National Electricity Rules)

Application for compensation in relation to the scheduling error on 1 May 2023 declared by AEMO on 21 June 2023

AGL Macquarie Pty Ltd (ABN 18 167 859 494) **Claimants**
AGL SA Generation Pty Ltd (ABN 84 081 074 204)
Snowy Hydro Limited (ABN 17 090 574 431)

REASONS FOR DETERMINATION

1. The claimants are registered as the *Market Generators* for the generating units referred to in the table below. The generating units are classified as *scheduled generating units*. Accordingly, the claimants are *Scheduled Generators* for their respective generating units.

<table>
<tr><th>Claimant</th><th>Generating units</th><th>Region</th></tr>
<tr><td rowspan="3">AGL Macquarie Pty Limited</td><td>Bayswater unit 1</td><td>NSW</td></tr>
<tr><td>Bayswater unit 3</td><td>NSW</td></tr>
<tr><td>Bayswater unit 4</td><td>NSW</td></tr>
<tr><td rowspan="2">AGL SA Generation Pty Limited</td><td>Barker Inlet units 1-12</td><td>SA</td></tr>
<tr><td>Torrens Island B unit 3</td><td>SA</td></tr>
<tr><td rowspan="4">Snowy Hydro</td><td>Guthega units 1-2</td><td>NSW</td></tr>
<tr><td>Murray 1 units 1-10 &
Murray 2 units 11-14</td><td>VIC</td></tr>
<tr><td>Tumut 3 units 1-6</td><td>NSW</td></tr>
<tr><td>Upper Tumut 1 units 1-4 &
Upper Tumut 2 units 5-8</td><td>NSW</td></tr>
</table>

2. On 21 June 2023, AEMO declared that, on 1 May 2023, a *scheduling error* had occurred from the 5-minute trading interval (**TI**) ending 00:05 to the TI ending 12:00, inclusive.[1]

3. The claimants' generating units were affected by the *scheduling error*, as I will describe below.

4. A *scheduling error* occurs (among other circumstances) if AEMO declares that it failed to follow the central dispatch process in **rule 3.8** of the National Electricity Rules (**NER**): NER

[1] AEMO, Spreadsheet of scheduling error declarations, incident no 54.

cl 3.8.24(a)(2). AEMO's declaration on 21 June 2023 was such a declaration that, during the identified intervals, AEMO failed to follow the central dispatch process.

5. If a *scheduling error* occurs, a Market Participant may apply to the *dispute resolution panel* (the **DRP**) for a determination as to compensation under NER **cl 3.16.2**. If so determined, any such compensation is payable from the *Participant compensation fund* (the **Fund**), which AEMO maintains and administers under Part 5, Div 7 of the National Electricity Law (**NEL**) and NER **cl 3.16.1**.

6. Each of the claimants has submitted an application to the Wholesale Energy Market Dispute Resolution Adviser (the **WEMDRA**) for compensation under cl 3.16.2. Those claims for compensation have been referred by the WEMDRA to the DRP constituted by me.

7. The claimants and AEMO have filed joint submissions, setting out the basis on which they agree that the claimants are entitled to compensation. I have also been provided, on a confidential basis, with spreadsheets that set out the calculation of the amount of compensation, as agreed between AEMO and each claimant individually.

8. I conducted a short hearing by videoconference on 4 June 2024, which was attended by representatives of each claimant and AEMO and by the WEMDRA.

Scheduling and dispatch of scheduled and semi-scheduled generation

9. As wholesale market operator, AEMO facilitates the wholesale trading of electricity through a centrally co-ordinated dispatch process (**central dispatch**), under which offers to supply electricity are scheduled and dispatched every five minutes.

10. The aim of the central dispatch process is to maximise the value of spot market trading on the basis of participants' dispatch offers and dispatch bids. That is, the lowest cost generating units and other supply sources available and needed to meet anticipated demand are *dispatched*, subject to the operational limits of power system equipment, non-scheduled load and generation, and other requirements needed to maintain power system security: **cl 3.8.1(b)**.

11. Dispatch offers and dispatch bids are processed by a computer system called the National Electricity Market Dispatch Engine (**NEMDE**). NEMDE is the dispatch algorithm that AEMO is required to develop and use for the purpose of central dispatch and pricing: **cl 3.8.1(d)**.

12. NEMDE is based on a constrained optimisation program that uses linear programming techniques to represent the power system. Network constraints can be applied in NEMDE to represent a reduced capacity to transfer electricity to, from or across elements of the power system at any point in time: **cl 3.8.10**.

13. AEMO forecasts electricity demand and non-scheduled generation 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 and other Registered Participants. NEMDE then performs an optimisation process to determine (among many other things) the required generation levels for scheduled generating units and semi-scheduled generating units, which are communicated to the relevant Generators in dispatch instructions.

14. This process is repeated every five minutes and produces a *spot price* for energy in each region, representing the marginal price of producing the next increment of electricity at that location.

15. Scheduled Generators whose dispatch offers are scheduled in the dispatch process receive a *dispatch instruction* to supply a target MW quantity of energy, and are required by the NER to comply with that instruction.

The scheduling error declared by AEMO

16. The Liddell Power Station generating units were deregistered from the NEM, at midnight (00:00 hours) at the start of 1 May 2023, following the decommissioning of those units in late April 2023.

17. But the deregistration of the Liddell units was not reflected in one of the NEMDE constraint equations. In particular, from 00:00 on 1 May 2023, the right hand side (**RHS**) terms in constraint N>>NIL_33_34 for each of the 3 deregistered Liddell units were changed to the default values of 500 MW, instead of zero MW. This saw a total of 1,500 MW (500 MW × 3 Liddell units) incorrectly being subtracted from the RHS, which caused the constraint to bind unnecessarily.

18. As a consequence of that error, in order to prevent the constraint violating, NEMDE automatically dispatched down the quantity of energy feeding onto lines 33 and 34, and interconnector flow from Victoria to NSW was reduced.

19. The constraint was fixed, from 12:00 noon on 1 May 2023, by AEMO manually changing the default RHS values for all three former Liddell Power Station units to 0 MW.

20. The scheduling error therefore continued for precisely 12 hours, from midnight to midday on 1 May 2023.

How is compensation for a scheduling error required to be determined?

21. In an application for compensation under **clause 3.16.2**, the function of the DRP is to determine:

    a. whether compensation is payable to the claimant;

    b. if so, the amount or level of compensation; and

    c. the manner and timing of any payments from the Fund.

22. The DRP's determination must be made consistently with clause 3.16.2: **cl 3.16.2(c)**. I will focus first on how I am required to determine the first two questions.

23. As relevant to the first two questions, the key requirements of clause 3.16.2 for this determination are:

    a. A Generator who receives a dispatch instruction to operate its generating unit at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occurred[2] – that is, a generating unit that was "**under-dispatched**" – will be entitled to receive compensation in an amount determined by the DRP: **cl 3.16.2(d)**.

    b. In determining the level of compensation to which the claimant is entitled in relation to a *scheduling error*, the DRP must use the *spot price* as determined under rule 3.9, for each affected trading interval, including any spot prices that have been adjusted in accordance with rule 3.9.2B:[3] **cl 3.16.2(h)(3)**.

24. As to the first question, AEMO and the claimants agree that the *scheduling error* had the effect of limiting the permitted generation of some generating units below the levels at which they would have been dispatched, but for the error in constraint N>>NIL_33_34.

25. In order to identify the generating units that were under-dispatched by reason of the *scheduling error*, and to quantify that reduction in each affected generating unit's energy output (**ΔMWh**) in each TI, AEMO has rerun NEMDE for each TI in the morning of 1 May 2023, using the dispatch inputs in the dispatch offers that each Generator in fact submitted for the each TIs that morning, and the corrected form of constraint N>>NIL_33_34.

26. In order to determine the level of compensation to which affected participants are entitled, I must use the *spot price* as determined under **rule 3.9**.

The agreed calculation methodology and the amounts of compensation agreed between each claimant and AEMO

27. The amounts of compensation agreed between each claimant and AEMO have been calculated by comparing:

    a. the *trading amount* that each claimant would have earned for energy output in each affected TI at its "what if" dispatch level and at the spot price for that TI; with

---

2 The counterfactual dispatch outcome – being the level at which a Generator would have been instructed to operate if the scheduling error had not occurred – is referred to hereafter as the **"what if"** dispatch level.

3 **Clause 3.9.2B** specifically authorises AEMO to replace the spot prices determined by NEMDE, if the dispatch outcomes for a trading interval are affected by a manifestly incorrect input. No manifestly incorrect input affected the dispatch outcomes that were determined by NEMDE version between TI 00:05 and TI 12:00. As a consequence, no question of adjustment of spot prices in accordance with clause 3.9.2B arises in this case.

b. the *trading amount* that each claimant in fact earned for its actual energy output in that TI at that spot price.

28. That comparison is carried out using the following methodology:

a. For each affected TI, rerun dispatch using a version of NEMDE with the corrected form of constraint N>>NIL_33_34.

b. For each TI, subtract the actual dispatch instruction quantity from the "what if" dispatch level for each unit, to determine the ΔMWh for that TI.

c. Disregard any ΔMWh for a unit in a TI that is negative.[4]

d. Multiply each positive ΔMWh by the applicable *spot price* for the TI, the intra-regional loss factor for the unit and an adjustment factor. This adjustment factor is a ratio between the metered sent out energy and the dispatch instruction quantity for the TI.

e. Since the ΔMWh were not actually produced and supplied by the Generator, any short run marginal costs (**SRMC**) would not have been incurred. Therefore, deduct a sum equal to the ΔMWh multiplied by an assumed SRMC. The assumed SRMC is taken from the 2022 ISP Inputs, Assumptions and Scenarios Report,[5] for the relevant generation type and region.

f. Sum all amounts for the trading intervals during the scheduling error period.[6]

g. The amount of compensation is the sum of those amounts, or $0 if the sum at step (f) is negative.

<u>Taking account of intertemporal inflexibilities in calculating the amount of compensation</u>

29. The calculation of the "what if" dispatch level is based on the dispatch offer inputs (including starting MW and ramp rates) that each claimant in fact submitted for the affected TIs on 1 May 2023. That is, the reconstructed "what if" dispatch level for each TI is not modified to take account of ramp rate or other inflexibilities that would limit the amount by which a dispatch target in one TI may be increased or decreased from a unit's actual level of output at the end of the previous TI. That "non-intertemporal" basis is the same basis on which the "what if" dispatch levels have most commonly been calculated in previous compensation applications.

---

4 See paragraphs 32 to 36 below.

5 AEMO, 2022 Inputs, Assumptions and Scenarios Workbook published 30 June 2022, Worksheet: Existing Gen Data Summary, Progressive Change scenario 2022-23 SRMC ($/MWh)

6 See paragraphs 30 and 31 below.

Taking account of negative spot prices in the NSW region

30. During the affected period on 1 May 2023, negative spot prices occurred in the NSW region for 2 trading intervals. Those negative spot prices resulted in step (d) of the calculation methodology returning a negative value for generating units in NSW that were dispatched during those trading intervals. Those negative values represented benefits realised by the Generator from having been under-dispatched during a negatively-priced trading interval.

31. By step (f) of the calculation methodology, those negative values (benefits) were netted off against the positive values (costs) that resulted from under-dispatch during positively-priced intervals. That approach to benefits received in negatively-priced intervals accords with the approach adopted in a number of previous DRP scheduling error decisions.[7]

Should over-dispatch in positive-price TIs also be taken into account?

32. The issue of benefits earned from having been under-dispatched in negative-price TIs also raises the question whether the compensation methodology should account in a similar way for Generators who benefit from having been over-dispatched (rather than under-dispatched) during positive-price TIs.

33. In this case, the agreed compensation spreadsheets reveal that one generating unit was over-dispatched, rather than under-dispatched, in 4 TIs. If a unit is over-dispatched, then it returns a negative ΔMWh for that interval, by step (b) of the calculation methodology, which is then disregarded at step (c). As such, any benefit that the Generator obtains by reason of its unit being over-dispatched during a positively-priced TI is not netted off against the costs that it incurs by being under-dispatched in other TIs across the *scheduling error* period.

34. In my previous determination, in respect of the *10 August 2022 scheduling error*, I noted that there is a real question whether the benefits of being over-dispatched in one or more positive-price TIs during a scheduling error should also be netted off against the costs for which compensation is claimed, in a similar way to how the benefits of being under-dispatched in negatively-priced periods are netted off. But I also noted that, as there were fairly arguable legal arguments for and against that view, and because the benefits resulting from over-dispatch were small, I was content to award compensation to the claimants without netting off any benefit received for over-dispatch, in accordance with the agreed methodology.

35. The benefits of over-dispatch that accrued for one generating unit in this case are also small, and so I am once again content to follow step (c) of the parties' agreed methodology in this case.

36. That said, I remain of the view that the question whether the netting-off of any benefits received from over-dispatch may be required (or permitted) under cl 3.16.2 is a question that

---

7 See, eg, the previous DRP determinations awarding compensation for the *Dundonnell WF scheduling error* (2021), at [27], the *Tasmanian scheduling error* (2016), at [13(d)], and the *UIGF scheduling error* (2012), at [34(i)].

may warrant attention by a DRP in compensation claims flowing from future *scheduling errors*, particularly if the over-dispatch results in a more substantial benefit being realised during a future *scheduling error*.

<u>The agreed compensation amounts</u>

37. On the basis of that agreed modelling and methodology, I am satisfied that each claimant:

    a. was instructed, in one or more of the affected TIs, to operate at a lower level than the level at which it would have been instructed to operate had the *scheduling error* not occurred; and

    b. accordingly, is entitled to receive compensation for its energy output forgone as a consequence of the *scheduling error*, in the amounts stated in the determination, subject to my consideration of the adequacy of the balance of the Fund below.

38. In the result, the aggregate of the agreed compensation for all claimants arising from the 1 May 2023 *scheduling error* is $293,133.03, comprised of the following individual amounts:

AGL Macquarie	$59,177.03
AGL SA Generation	$3,082.24
Snowy Hydro	$230,873.76

The Participant compensation fund

39. AEMO maintains the Fund for the purpose of paying compensation, as determined by the DRP, for *scheduling errors* to Scheduled Generators, Semi-Scheduled Generators and Scheduled Network Service Providers.

40. Each financial year, AEMO is required to top up the Fund in the amount of $1,000,000, or the difference between $5,000,000 and the amount which AEMO reasonably estimates will be the balance of the Fund at the end of the financial year, whichever is the lesser.

41. As at 30 April 2024, the balance of the Fund was $5,213,822.75.

42. In determining the level of compensation to which the claimants are entitled, I am required to:

    a. take into account the current balance of the Fund and the potential for further liabilities to arise during the financial[8] year; and

---

8 See decision of the DRP (constituted by The Hon MJ Clarke QC and Greg Thorpe), *Macquarie Generation scheduling error* , 24 April 2008, at [14]-[18].

b. recognise that the aggregate liability of the Fund in any financial year in respect of *scheduling errors* cannot exceed the balance of the Fund that would have been available at the end of that year if no compensation payments had been made during that year: **cl 3.16.2(h)(4)-(5)**.

43. The approach to be taken by a DRP in considering these matters has been helpfully analysed in the *Macquarie Generation* decision of the DRP, at [10]-[26].

44. Of itself, the $293,133.03 aggregate sum of compensation for the 1 May 2023 *scheduling error* will not cause any substantial depletion of the Fund.

45. At the hearing on 4 June 2024, the WEMDRA informed me that, in accordance with her usual practice, she had requested AEMO to compile a list of participants who might be affected by the *scheduling error*. At her request, on around 20 and 27 May 2024, AEMO notified those affected participants with potential claims of $10,000 or more about the establishment of this DRP, and invited them to notify the WEMDRA if they wished to be joined to this DRP process. The AGL parties joined this DRP in response to that request. The WEMDRA also informed me that one other participant had indicated that it might seek to claim compensation for this *scheduling error*.

46. AEMO also advised that, as at 4 June 2024, it expected that it may shortly declare one further *scheduling error*, but it expects that the losses caused by that event are likely to be very low.

47. I am therefore satisfied that, having regard to the potential for further liabilities in the few remaining weeks of this financial year, it is appropriate to award the full amount of the compensation to each claimant out of the Fund.

Costs of the DRP and the WEMDRA

48. **Clause 8.2.8(a)** provides that the costs of any dispute resolution process, including the costs incurred by the WEMDRA in constituting and convening the DRP,[9] are to be borne equally by the parties to the dispute unless **cl 8.2.8(b)** applies,[10] or otherwise agreed by the parties.

49. In this case, the parties jointly submitted that the costs of the DRP and the WEMDRA, and the manner and timing of payment of those costs, are to be determined by the DRP. This

9 **Clause 8.2.8(a)** refers to costs incurred by WEMDRA "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. **Clause 8.2.6A** is the clause that requires WEMDRA to establish a DRP, out of the members of the pool established under **cl 8.2.2(e)**, whenever it becomes necessary to refer a dispute for resolution by a DRP.

10 **Clause 8.2.8(b)** provides: "Costs of the dispute resolution processes … may be allocated by the *DRP* for payment by one or more parties as part of any determination. … [I]n 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".

submission reflects my decision as to the costs of the DRP and the WEMDRA in my determinations of the *Dundonnell WF scheduling error* and the *10 August 2022 scheduling error*.

50. As this is an uncontested application for *scheduling error* compensation, I consider that it is both permissible and appropriate for the claimants' liability for their respective shares of the DRP and WEMDRA costs to be included in the compensation payable out of the Fund, for the same reasons that I gave in paragraphs 37 to 58 of the *Dundonnell WF scheduling error* determination.

51. The parties were content that the DRP and WEMDRA costs should be allocated one-half to Snowy Hydro and one-quarter each to AGL Macquarie and AGL SA Generation, and I consider that it is appropriate to apportion the costs in those proportions.

52. The DRP costs of this determination are $6,375, inclusive of GST. The WEMDRA's fee for facilitating these applications for compensation is $9,900, inclusive of GST.

53. I will therefore order, in substance, that:

    a. Each claimant is entitled to compensation out of the Fund in the agreed amounts set out in paragraph 38 above (the **loss amount**), plus its respective share of the costs of the DRP and the WEMDRA.

    b. AEMO pay each claimant its loss amount out of the Fund; and

    c. on behalf of the Claimants, AEMO shall pay the DRP and WEMDRA costs out of the Fund to the DRP and the WEMDRA.

20 June 2024

[redacted]