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 10 August 2022 declared by AEMO on 12 August 2022

AGL Dalrymple Pty Ltd (ABN 47 122 144 709) **Claimants**
(formerly Accel Energy Retail Pty Ltd)
AGL Hydro Partnership (ABN 86 076 691 481)
AGL Loy Yang Marketing Pty Ltd (ABN 19 105 758 316)
AGL Macquarie Pty Ltd (ABN 18 167 859 494)
AGL PARF NSW Pty Ltd (ABN 33 615 408 770)
AGL SA Generation Pty Ltd (ABN 84 081 074 204)
Alinta Energy Retail Sales Pty Ltd (ABN 22 149 658 300)
Hydro-Electric Corporation (ABN 48 072 377 158)
Limondale Sun Farm Pty Ltd (ABN 66 617 558 728)
Telstra Energy (Generation) Pty Ltd (ABN 32 613 554 233)

DETERMINATION

The Dispute Resolution Panel determines that:

1. As a consequence of the scheduling error that occurred on 10 August 2022, 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 Dalrymple	$1,897.61
AGL Hydro Partnership	$7,677.72
AGL Loy Yang	$15,973.53
AGL Macquarie	$9,466.18
AGL PARF NSW	$26,892.40

AGL SA Generation	$2,023.98
Alinta	$25,897.16
Hydro-Electric Corporation	$111,129.12
Limondale	$2,160.05
Telstra Energy	$25,169.09

b. a one-tenth share of the costs of the Dispute Resolution Panel (the **DRP**) and the Wholesale Market Dispute Resolution Panel (the **WEMDRA**)

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.

16 May 2023

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 10 August 2022 declared by AEMO on 12 August 2022

AGL Dalrymple Pty Ltd (ABN 47 122 144 709) **Claimants**
(formerly Accel Energy Retail Pty Ltd)
AGL Hydro Partnership (ABN 86 076 691 481)
AGL Loy Yang Marketing Pty Ltd (ABN 19 105 758 316)
AGL Macquarie Pty Ltd (ABN 18 167 859 494)
AGL PARF NSW Pty Ltd (ABN 33 615 408 770)
AGL SA Generation Pty Ltd (ABN 84 081 074 204)
Alinta Energy Retail Sales Pty Ltd (ABN 22 149 658 300)
Hydro-Electric Corporation (ABN 48 072 377 158)
Limondale Sun Farm Pty Ltd (ABN 66 617 558 728)
Telstra Energy (Generation) Pty Ltd (ABN 32 613 554 233)

REASONS FOR DETERMINATION

1. The claimants are registered as the *Market Generators*[1] for the generating units referred to in **Annexure A**.

2. The generating units are classified as *scheduled generating units* or *semi-scheduled generating units*. Accordingly, the claimants are *Scheduled Generators* or *Semi-Scheduled Generators* for their respective generating units.

3. On 12 August 2022, declared that a *scheduling error* had occurred from the 5-minute trading interval (**TI**) ending 11:35 to the TI ending 12:35 on 10 August 2022, inclusive.[2] On

[1] One of the claimants, AGL Dalrymple Pty Ltd, is the operator of a battery, and so is registered both as a Market Generator and a Market Customer.

[2] AEMO, Spreadsheet of scheduling error declarations, incident no 43.

24 October 2022, AEMO published a **Scheduling Error Report**,[3] in which it set out the results of its investigation into the *scheduling error*.

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

5. 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 **cl 3.8.24(a)(2)**. AEMO's declaration on 12 August 2022 was such a declaration that, during the identified intervals, AEMO failed to follow the central dispatch process.

6. 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**.

7. 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.

8. 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.

9. I conducted a short hearing by videoconference on 4 April 2023, which was attended by representatives of each claimant and AEMO and by the WEMDRA.

Scheduling and dispatch of semi-scheduled generation

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

11. 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)**.

---

[3] AEMO, *Scheduling error report: NEM Dispatch Engine – Constraint Calculation Error – 10 August 2022*, 24 October 2022.

12. Dispatch offers, dispatch bids and market ancillary service offers 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)**.

13. 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**. Ancillary services constraints are also applied in NEMDE to determine the quantities of each type of FCAS required in the NEM or in any of its regions: **cl 3.8.11**.

14. 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.

15. 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.

16. Scheduled Generators and Semi-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.

Dispatch of semi-scheduled generating units

17. The way in which semi-scheduled generating units are dispatched, and the way in which they must comply with dispatch instructions, is different from scheduled generating units, as I describe briefly below.

18. For each TI, AEMO prepares a forecast of the available capacity of each semi-scheduled generating unit to generate electricity from its energy source, which is the unconstrained intermittent generation forecast (**UIGF**).

19. Typically,[4] the dispatch level that AEMO notifies in the *dispatch instruction* for a semi-scheduled generating unit in any TI is equal to its UIGF for that TI. The *dispatch instruction* also indicates whether the TI is a *semi-dispatch interval* or a *non semi-dispatch interval*.

---

[4] Subject to any limits on availability indicated by the Generator's dispatch offer or other technical limits communicated to AEMO.

a. In a semi-dispatch interval, the generating unit's active power at the end of the TI must not exceed the specified dispatch level: **cl 4.9.8(a2)**.

b. In a non semi-dispatch interval, the generating unit's active power at the end of the TI may vary from (that is, may fall short of or exceed) the specified dispatch level as a result of the availability of wind or solar resource during that TI: **cl 4.9.8(a1)**.

Over-constrained dispatch

20. Given its complexity, it is inevitable that errors can occur from time to time in the operation of NEMDE to produce dispatch outcomes. This is why the mechanism for compensating affected Market Participants for *scheduling errors* exists.

21. One of the ways in which the dispatch process provided for in the NER seeks to avoid errors is by providing for an automated resolution in the event that NEMDE produces an infeasible dispatch solution, known as "over-constrained dispatch". As a backstop against the possibility of over-constrained dispatch, AEMO is required to establish procedures to resolve infeasible dispatch solutions by allowing relaxation of power system constraints, so as to achieve a reasonable dispatch outcome consistent with AEMO's obligations to maintain power system security and with the pricing principles stated in cl 3.9.1: **cl 3.8.1(c)**. These guidelines are set out in the *Over-Constrained Dispatch Rerun Process Document*, which was published by AEMO on 16 June 2011 (the **OCD Rerun Guidelines**).

22. At a high level, under the OCD Rerun Guidelines:

a. An over-constrained dispatch (**OCD**) run occurs when the marginal price in one or more regions would be above the market price cap ($15,500/MWh) or below the market floor price (−$1,000/MWh), due to the added cost of violated constraints. These added costs mean that energy and/or FCAS requirements in a region can only be met by the temporary violation of network and/or FCAS constraints above their secure limits.

b. The OCD rerun process aims to remove those constraint violation costs from energy and FCAS prices by rerunning dispatch with the violated constraints relaxed.

c. If an OCD condition is detected after the initial dispatch run for a TI, then an automatic in-line rerun of dispatch is carried out. If this resolves the OCD condition, then AEMO publishes the dispatch targets from the original dispatch run, together with prices as determined by the in-line rerun.

d. If the automatic in-line rerun does not resolve the OCD condition, then AEMO is required to issue a manual price dispatch interval market notice (**MPDI notice**), and an automatic off-line rerun is then carried out. If the automatic off-line rerun resolves the OCD condition, then AEMO publishes the revised prices from the off-line rerun.

If the OCD condition is resolved by automatic off-line rerun, this typically results in the adjusted prices being notified to the market by a price adjustment market notice (**PA notice**) before the end of the TI in which the OCD condition was detected.

e. If the automatic off-line rerun does not resolve the OCD condition, then AEMO is required to carry out a manual rerun of dispatch. Once the OCD condition is resolved through a manual rerun, then AEMO publishes revised prices to the market by a PA notice. Typically, that occurs well after the conclusion of the relevant TI.

23. It is also important to note that each of those OCD rerun processes only involves recalculation of the applicable spot prices for energy and/or FCAS, and does not involve any recalculation of the dispatch target or dispatch level notified to each generating unit.

The scheduling error declared by AEMO

24. Unlike most other *scheduling errors* that have been the subject of compensation determinations by the DRP, this *scheduling error* was not caused by an isolated data error or error in the formulation of a constraint equation.

25. Rather, this *scheduling error* occurred as the result of AEMO implementing a software upgrade to NEMDE (the **affected NEMDE version**) that was affected by a programming error, which resulted in the erroneous calculation of a number of FCAS and system strength constraints. The system-wide nature of the software error, and the fact that AEMO had to promptly uninstall the affected NEMDE version, have some significance for the way in which compensation is to be determined for this *scheduling error*, as I will explain further below.

26. On 10 August 2022, AEMO implemented the NEMDE software upgrade with effect from 11:30 am (that is, for TI 11:35). The error resulted in artificially high requirements for fast and slow contingency FCAS in all regions, and for system strength services in Queensland. In turn, these constraints resulted in OCD dispatch runs occurring in each TI, and significant unexpected changes to dispatch and pricing outcomes.

27. After noticing these abnormal outcomes, AEMO promptly reversed the software change prior to 12:35 pm. As a result, the affected NEMDE version was operational between TI 11:35 and TI 12:35, inclusive (the **affected TIs**). After the previous version of NEMDE was reinstated, from TI 12:40 onwards, the OCD dispatch runs and abnormal outcomes ceased and the dispatch process continued to operate normally.

28. As shown in the table below, each trading interval between TI 11:35 and TI 12:35 resulted in an OCD dispatch run. The dispatch runs for TIs 11:35–11:50 and TIs 12:10–12:20 were resolved by in-line or automated off-line reruns, in accordance with the OCD Rerun Guidelines. The remaining trading intervals (that is, TIs 11:55–12:05 and TIs 12:25–12:35) were not resolved automatically, and so were required to be resolved by AEMO manually.

Trading interval	OCD rerun	Market notice
10/08/2022 11:35	Resolved (inline rerun)	
10/08/2022 11:40	Resolved (inline rerun)	
10/08/2022 11:45	Resolved (inline rerun)	
10/08/2022 11:50	Resolved (inline rerun)	
10/08/2022 11:55	Unresolved	100827
10/08/2022 12:00	Unresolved	100829
10/08/2022 12:05	Unresolved	100830
10/08/2022 12:10[5]	Resolved (inline rerun)	
10/08/2022 12:15	Resolved (automated offline rerun)	100832 & 100833
10/08/2022 12:20	Resolved (inline rerun)	
10/08/2022 12:25	Unresolved	100834
10/08/2022 12:30	Unresolved	100835
10/08/2022 12:35	Unresolved	100836

29. In carrying out the manual off-line reruns for TIs 11:55–12:05 and TIs 12:25–12:35, AEMO used the NEMDE version that was in operation prior to TI 11:35 and which was reinstated after TI 12:35 (the **reinstated NEMDE version**). This was necessary as, otherwise, the constraint relaxation process for the manual off-line rerun would still have been affected by the fundamental software error in the affected NEMDE version which had caused the OCD outcomes.

30. On 11 August 2022, AEMO then decided to revise the energy and FCAS spot prices in all regions for all 13 affected TIs between TI 11:35 and TI 12:35, using the reinstated NEMDE version and the dispatch inputs that were in fact used in the original dispatch runs for the affected TIs. As AEMO acknowledges in the Scheduling Error Report, its revision of prices for the trading intervals that had previously been resolved through automatic in-line or automatic off-line reruns was not contemplated by the NER. The spot prices as revised by AEMO on 11 August 2022 were used in due course in settlements for all Market Participants.

31. In **Annexure B** to these reasons, I have set out:

    a. the spot price in each region originally determined by the affected NEMDE version for each affected trading interval;

    b. the spot price in each region, as resolved by the automatic off-line or automatic in-line reruns for TIs 11:35–11:50 and TIs 12:10–12:20; and

    c. the spot price in each region, as resolved by AEMO's manual off-line rerun, using the reinstated NEMDE version, for each affected trading interval.

---

5 I have been informed by AEMO that the dispatch run for TI 12:10 was resolved in-line, and was not unresolved as shown in Table 1 in the Scheduling Error Report.

32. As I have noted above, AEMO has declared that a *scheduling error* occurred from TI 11:35 to TI 12:35 because, during those intervals, AEMO failed to follow the central dispatch process set out in **rule 3.8**. The central dispatch process in rule 3.8 includes reruns performed to resolve OCD dispatch outcomes in accordance with the OCD Rerun Guidelines (which are made under **cl 3.8.1(c)**). However, the NER and the OCD Rerun Guidelines do not expressly contemplate how dispatch is to be rerun in the event that the original dispatch outcomes were determined under a NEMDE software version that has been deactivated due to unexpected software errors.

33. In these circumstances, I consider that it is appropriate to characterise the *scheduling error* as being the implementation of the affected NEMDE version between TI 11:35 and TI 12:35 inclusive. Because the affected NEMDE version produced OCD dispatch outcomes and extreme prices, I accept that AEMO has acted reasonably in using the reinstated NEMDE version to determine the "what if" dispatch outcomes to be used in determining compensation for the *scheduling error*.

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

34. 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.

35. 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.

36. 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[6] – 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

[6] 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.

each affected trading interval, including any spot prices that have been adjusted in accordance with rule 3.9.2B:[7] **cl 3.16.2(h)(3)**.

37. As to the first question, AEMO and the claimants agree that the *scheduling error* (that is, the operation of the affected NEMDE version) had the effect of limiting the permitted generation of some generating units below the levels at which they would have been dispatched, had the affected NEMDE version not been implemented.

38. 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 trading interval, AEMO has rerun dispatch for each affected TI, using the reinstated NEMDE version and the dispatch inputs in the dispatch offers that each Generator in fact submitted for the affected TIs on 10 August 2022. As I have noted in paragraph 33 above, I consider that it was reasonable for AEMO to have used the reinstated NEMDE version to carry out the comparison.

39. The second step is arguably more complicated, in the unusual circumstances of this case. 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**.

    a. **Clause 3.9.1** sets out principles applying to the determination of *spot prices*, including that a *spot price* for a regional reference node is determined by the central dispatch process for each trading interval: **cl 3.9.1(a)(2)**.

    b. **Clause 3.9.2(c)** provides that:

    > Each time the *dispatch algorithm* is run by *AEMO*, it must determine *spot price* for each *regional reference node* for a *trading interval* in accordance with clause 3.8.21(b), provided that if *AEMO* fails to run the *dispatch algorithm* to determine *spot prices* for any *trading interval* then the *spot price* for that *trading interval* is the last *spot price* determined by the *dispatch algorithm* prior to the relevant *trading interval*.

    c. **Clause 3.9.2(e)** sets out four exceptions to clause 3.9.2(c), including when a trading interval is declared to be an *intervention trading interval*, or occurs during an *administered price period* or a period when the spot market has been suspended by AEMO. None of those exceptions applies to this case.

---

[7] **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 the affected NEMDE version between TI 11:35 and TI 12:35. As a consequence, no question of adjustment of spot prices in accordance with clause 3.9.2B arises in this case.

d. **Clause 3.8.21(b)** provides that AEMO must run the dispatch algorithm for each trading interval, and then adds that:

> If the *dispatch algorithm* is not successfully run for any *trading interval* then the values of the last successful run of the *dispatch algorithm* must be used for that *trading interval*.

40. On one view, it may be said that, in determining the amount of compensation payable, **cl 3.16.2(h)(3)** requires me:

a. to use the *spot prices* that were determined by the affected NEMDE version between TI 11:35 and TI 12:35;

b. but, for those trading intervals where the OCD dispatch outcomes were not able to be resolved by in-line or automatic off-line reruns (that is, TIs 11:55–12:05 and TIs 12:25–12:35), to use the spot prices that were determined in the previous successful runs of the dispatch algorithm (that is, in TI 11:50 and TI 12:20, respectively).

41. That argument depends on a narrower characterisation of the s*cheduling error* than I have given at paragraph 33 above. In substance, that argument takes the *scheduling error* as having arisen from AEMO's manual off-line rerun of the dispatch outcomes for TIs 11:55–12:05 and TIs 12:25–12:35, rather than as having arisen from the use of the affected NEMDE version per se.

42. On the wider characterisation of the *scheduling error*, the use of the affected NEMDE version itself amounted to a failure to follow the central dispatch process set out in rule 3.8. On that view, it is at least reasonably arguable that AEMO's revision of the spot prices in each region for each interval between TI 11:35 and TI 12:35, determined using the reinstated NEMDE version (the **redetermined spot price**), should be applied as "the *spot price* as determined under rule 3.9" in determining the amount of compensation to which each affected participant is entitled, under c**l 3.16.2(h)(3)**.

43. The claimants and AEMO have, by their agreed submissions, invited me to apply the approach described in paragraph 42 above. In the circumstances of this case, I consider that it is appropriate to do so because:

a. that approach is at least reasonably arguable in the exceptional circumstances of this *scheduling error*;

b. it was reasonable for AEMO to have used the reinstated NEMDE version to arrive at the redetermined spot prices, in circumstances where the spot prices produced by the reinstated NEMDE version were applied to determine spot prices market-wide for the 13 affected TIs; and

c. as can be seen from a comparison between the spot prices determined by the affected NEMDE version for NSW, South Australia, Tasmania and Victoria, and the spot prices for those regions later re-determined by the reinstated NEMDE version, adopting that approach will result in a considerably lower amount of compensation being awarded and drawn down from the Fund, than if the first approach were applied.

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

44. In the circumstances of this case, 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 redetermined spot price; with

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

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

   a. For each affected TI, re-run dispatch using the previous version of NEMDE.

   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.

   d. Multiply each positive ΔMWh by the applicable *spot price* for the TI as finally published, 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,[8] for the relevant generation type and region.

   f. Exclude any negative outcomes of these calculations.

   g. Sum the positive amounts for all of the affected TIs.

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

Taking account of intertemporal inflexibilities in calculating the amount of compensation

46. With one exception, 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 10 August 2022. 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 been calculated for previous compensation applications.

47. However, in this case, Alinta has agreed with AEMO to an amount of compensation that has been modelled by a method that does take into account the intertemporal inflexibilities that I have described above. In circumstances where compensation calculated on that "intertemporal" basis has been agreed between Alinta and AEMO, where each of the other claimants is content to claim compensation calculated on the non-intertemporal basis, and where the amounts of these claims are relatively modest overall, I am satisfied that it is appropriate to approve the agreed amount of compensation for Alinta calculated on that different basis.

Taking account of negative spot prices in the Queensland region

48. At the commencement of this DRP process, a compensation claim was submitted by a Generator in the Queensland region. As can be seen from Annexure B, the redetermined *spot prices* for the Queensland region were negative for 8 of the 13 affected TIs.

49. On review of the compensation spreadsheet agreed between AEMO and that Generator, the Generator was under-dispatched in each of the 13 affected TIs. As a consequence of having been under-dispatched in each of the 5 positive-price TIs, the Generator realised a loss because of the *scheduling error*. Conversely, by having been under-dispatched in each of the 8 negative-price TIs, the Generator realised a benefit because of the *scheduling error*. On a net basis, across all 13 affected TIs, the Generator was shown to have received an overall benefit (rather than a loss) because of the *scheduling error*.

50. As a consequence of step (f) in the agreed calculation methodology summarised above, the compensation spreadsheet for that Generator recorded the gross loss incurred from the 5 positive-price TIs, without netting of those losses against the benefits that the Generator received from having been under-dispatched in the other 8 negative-price TIs.

51. By contrast, in a number of other compensation claims previously approved by DRPs,[9] any benefits realised by a claimant from having been under-dispatched in negative-price TIs have

---

9 See 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)].

been netted off, so that the gains realised in the negative-price TIs are taken into account, rather than ignored, in the calculation process.

52. Having identified that difference in approach towards benefits received in negative-price TIs, I raised the matter with the affected Generator and AEMO and questioned whether it was appropriate to award compensator to that Generator in this case. I invited the Generator and AEMO to make further submissions to the effect that I was required to (or should) award compensation to the Generator for the gross losses as recorded in the agreed compensation spreadsheet.

53. At that juncture, the affected Generator indicated that it wished to withdraw its claim for compensation.

54. Noting that I did not receive any further submissions on the question, my provisional view is that it would have been inappropriate to award compensation to that Generator in circumstances where, by reason of the negative redetermined *spot prices* in Queensland, it appears to have made a net benefit, rather than incurred a net loss, as a result of the *scheduling error*.

<u>Should over-dispatch in positive-price TIs also be taken into account?</u>

55. 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.

56. In this case, the agreed compensation spreadsheets reveal that, in some of the affected TIs, a small number of the claimants' generating units were dispatched to provide a <u>greater</u> quantity of output than the "what if" output subsequently determined by AEMO – that is, that those generating units were **over-dispatched**. In the TIs when those generating units were over-dispatched, then they are recorded as having a negative ΔMWh. As a consequence, those Generators would have received a <u>benefit</u> in those TIs (before any allowance is made for fuel costs), by reason of having received a higher *trading amount* than they would have received at the "what if" dispatch level.

57. By reason of step (c) in the agreed calculation methodology above, any such benefits that a Generator may have realised by reason of having been over-dispatched in some of the affected TIs is disregarded (and not netted off) in calculating the agreed compensation for that Generator.

58. To my mind, there is a real question whether the benefits that a Generator may receive by reason of having been over-dispatched in a positive-price TI should be netted off against the losses that the Generator incurs from having been under-dispatched in other positive-

price TIs during the *scheduling error*. Particularly as periods of negative pricing have become more frequent in the NEM, it seems incongruous that benefits received during negative-price periods should be netted off in determining the proper amount of compensation, while benefits received from having been over-dispatched during positive-price periods should not be.

59. That said, there is some scope for disagreement about whether **cl 3.16.2** would permit the netting-off of benefits received from over-dispatch during positive-price TIs.

    a. As I have noted above, the threshold criterion for entitlement to compensation is that a Generator will be entitled to receive compensation if it "receives an instruction … to operate at a lower level than the level at which it would have been instructed to operate" – that is, if it has been under-dispatched: **cl 3.16.2(d)**.

    b. On the narrower view, if a Generator has been both under-dispatched and over-dispatched in different TIs during a scheduling error, cl 3.16.2(d) would only permit a DRP to have regard to the losses it has incurred in the TIs in which it was under-dispatched, and to disregard any benefits that the Generator may have received from having been over-dispatched in other TIs.

    c. Conversely, on the broader view, cl 3.16.2(d) is satisfied for any Generator whose generating unit is under-dispatched in <u>any</u> TI during a *scheduling error*. Thereafter, the DRP has a discretion to determine the level of compensation to which that Generator is entitled and, in doing so, may have regard to the benefits that a Generator has received from having been over-dispatched in some positive-price TIs, as well as to the losses (or benefits) that the Generator has incurred from having been under-dispatched in one or more positive-price (or negative-price) TIs.

60. The calculation methodology that has been agreed between AEMO and each claimant in this case is consistent with the narrower legal view above. In circumstances where the legal basis of the agreed method is at least fairly arguable, and because the financial impact of over-dispatch in this case appears to be small, I am satisfied that it is appropriate to award compensation to the claimants without netting off any benefits received for over-dispatch.

61. That said, I consider that the question whether the netting-off of an efforts received from over-dispatch may be required (or permitted) under cl 3.16.2 is a question that may warrant attention by a DRP in compensation claims flowing from future *scheduling errors*.

<u>The agreed compensation amounts</u>

62. On the basis of that agreed modelling, 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 balance of the Fund below.

63. In the result, the aggregate of the agreed compensation for all claimants arising from the 10 August 2022 *scheduling error* is $228,286.84,[10] arrived at from the following individual amounts:

AGL Dalrymple	$1,897.61
AGL Hydro Partnership	$7,677.72
AGL Loy Yang	$15,973.53
AGL Macquarie	$9,466.18
AGL PARF NSW	$26,892.40
AGL SA Generation	$2,023.98
Alinta	$25,897.16
Hydro-Electric Corporation	$111,129.12
Limondale	$2,160.05
Telstra Energy	$25,169.09

The Participant compensation fund

64. 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.

10 The joint submissions of the parties record the aggregate amount of compensation as being $231,041.80; however, that sum erroneously includes the compensation previously claimed in respect of the Generator that withdrew from this request for compensation.

65. 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.

66. As at 31 March 2023, the balance of the Fund was $5,174,159.

67. 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[11] year; and

    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)**.

68. 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].

69. Of itself, the $228,286.84 aggregate sum of compensation for the 10 August 2022 *scheduling error* will not cause any substantial depletion of the Fund.

70. As at 28 April 2023, AEMO has advised that:

    a. there are no other outstanding claims for compensation for other *scheduling errors* that AEMO has declared; and

    b. AEMO has declared one further recent event, which occurred on 6 April 2023, as a *scheduling error*. AEMO's initial estimate of the total generation impact from that event is approximately $425,000. AEMO has advised that it has not yet received any compensation claim in respect of that *scheduling error*.

71. I am therefore satisfied that it is appropriate to award the full amount of the compensation to each claimant out of the Fund.

---

[11] 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].

Costs of the DRP and the WEMDRA

72. **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,[12] are to be borne equally by the parties to the dispute unless **cl 8.2.8(b)** applies,[13] or otherwise agreed by the parties.

73. 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 submission reflects my decision as to the costs of the DRP and the WEMDRA in my determination of the *Dundonnell Wind Farm* claim for compensation in December 2021.

74. 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.

75. The DRP costs of this determination are $10,200, inclusive of GST. The WEMDRA has advised me that her costs of this determination are $13,522.60, inclusive of GST.

76. 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 63 above (the **loss amount**), plus a one-tenth 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.

16 May 2023

Tom Clarke

---

12 **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.

13 **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 maters, 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".

Annexure A: Claimants and affected generating units

Claimant	Generating units
AGL Dalrymple Pty Limited (formerly Accel Energy Retail Pty Limited)	Dalrymple North BESS
AGL Hydro Partnership	Broken Hill Solar Plant Bogong/Mackay West Kiewa 1
AGL Loy Yang Marketing Pty Ltd	Loy Yang A1 Loy Yang A3 Loy Yang A4
AGL Macquarie Pty Limited	Bayswater 3 Bayswater 4 Liddell 1 Liddell 2
AGL PARF NSW Pty Ltd	Silverton Wind Farm
AGL SA Generation Pty Limited	Barker Inlet
Alinta Retail Sales Pty Ltd	Loy Yang B1
Hydro-Electric Corporation	Cethana Devils Gate Fisher Gordon John Butters Lemonthyme/Wilmot Mackintosh Poatina 110 kV Reece 1 Reece 2 Trevallyn Tribute Tungatinah
Limondale Sun Farm Pty Ltd	Limondale Solar Farm 1
Telstra Energy (Generation) Pty Ltd	Murra Warra Wind Farm

Annexure B: Original and subsequently resolved spot prices for the 13 affected trading intervals

Spot prices in each region originally determined by NEMDE

TI	NSW1	QLD1	SA1	TAS1	VIC1
10/08/2022 11:35	450.02	-13.00	439.50	15500.00	461.38
10/08/2022 11:40	1002.32	526.00	1195.34	15500.00	1156.80
10/08/2022 11:45	160.42	131.89	1853.20	15500.00	1746.67
10/08/2022 11:50	-49.00	-78.70	5140.45	15500.00	5001.00
10/08/2022 11:55	661.74	-78.70	757.40	15500.00	732.78
10/08/2022 12:00	508.32	-45.25	995.95	15500.00	963.36
10/08/2022 12:05	464.43	-50.00	1070.81	15500.00	1031.77
10/08/2022 12:10	231.00	30.00	831.60	15500.00	820.30
10/08/2022 12:15	568.53	208.01	952.42	995.44	873.71
10/08/2022 12:20	350.97	149.10	1351.34	1335.11	1202.16
10/08/2022 12:25	-60.00	-51.18	4438.66	4134.49	3948.12
10/08/2022 12:30	14.37	11.84	1991.42	1823.60	1739.19
10/08/2022 12:35	499.87	146.00	1134.69	1057.94	983.96

Spot prices in each region as resolved by the inline rerun or the automated offline rerun for TIs 11:35 to 11:50, and TIs 12:10 to 12:20

TI	NSW1	QLD1	SA1	TAS1	VIC1
10/08/2022 11:35	450.02	-13.00	439.50	13248.39	461.38
10/08/2022 11:40	1002.32	526.00	1195.34	15500.00	1156.80
10/08/2022 11:45	160.42	131.89	1853.20	15500.00	1746.67
10/08/2022 11:50	-49.00	-78.70	5140.45	15500.00	5001.00
…					
10/08/2022 12:10	231.00	30.00	831.60	15500.00	820.30
10/08/2022 12:15	568.53	208.01	952.42	995.44	873.71
10/08/2022 12:20	350.97	149.10	1351.34	1335.11	1202.16

Spot prices in each region as finally determined through the manual offline rerun, using the reinstated version of NEMDE

TI	NSW1	QLD1	SA1	TAS1	VIC1
10/08/2022 11:35	160.42	-13.00	168.71	233.35	173.25
10/08/2022 11:40	450.02	363.58	490.47	487.36	464.78
10/08/2022 11:45	266.23	30.00	329.42	333.79	301.01
10/08/2022 11:50	0.00	-93.55	468.11	473.32	426.10
10/08/2022 11:55	160.42	-53.25	185.56	239.13	177.64
10/08/2022 12:00	237.68	-51.00	274.31	313.34	261.17
10/08/2022 12:05	231.00	-93.55	267.83	313.74	256.32
10/08/2022 12:10	0.00	-50.00	0.00	73.26	0.00
10/08/2022 12:15	275.08	24.10	329.82	252.30	301.01
10/08/2022 12:20	280.20	11.84	334.96	252.30	301.01
10/08/2022 12:25	266.21	-51.00	341.66	273.61	301.01
10/08/2022 12:30	159.91	-13.00	212.01	165.28	183.89
10/08/2022 12:35	231.00	18.34	293.06	313.41	256.68