Additional compensation claims arising from AEMO directions billing weeks 5 - 8 FINAL DETERMINATION

An independent expert report for AEMO

23 July 2021

Synergies Economic Consulting Pty Ltd
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1 Introduction

Synergies Economic Consulting (Synergies) was appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine additional compensation claims for two referred *directed participants* under clause 3.15.7B of the National Electricity Rules (NER).

AEMO is required by the NER to use reasonable endeavours to complete all obligations, including final settlement, no later than 30 weeks after the end of the direction. The intervention timetable requires that a final independent expert determination be delivered no later than 13 August 2021.

In accordance with the Intervention Settlement Timetables for the directions during billing weeks 5 to 8, Synergies is issuing this final report on 23 July 2021.

1.1 Structure of the report

In the remainder of this report, we set out the basis for our final determination regarding additional compensation claims resulting from these directions under the NER, as follows:

- Section 2 summarises the circumstances of the *directions* and sets out the additional compensation claim provisions of clause 3.15.7B relevant to the claims;
- Section 3 provides details of the *directions* made and initial compensation determined;
- Section 4 provides an overview of the claims made for additional compensation as a result of the *directions*;
- Section 5 provides our analysis of the additional compensation claims for Claim 1;
- Section 6 provides our analysis of the additional compensation claims for Claim 2; and
- Section 7 provides our final determination.

2 Claims under clause 3.15.7B

This section summarises the circumstances of the *directions* and sets out the additional compensation claim provisions of clause 3.15.7B relevant to the claims.

2.1 Basis of the *directions*

Section 116 of the NEL and clause 4.8.9 of the NER establish that AEMO may direct a *Registered Participant* to take relevant actions to maintain or restore the security or reliability of the power system.

AEMO issued *directions* (Table 1) to South Australian market participants during billing weeks 5 to 8 2021 to maintain the system in a secure operating state. For the purposes of clause 3.15.7B, these market participants were *directed participants* on several occasions between 25 January and 25 February 2021.

Claimant 1 modified the operations of four of its generating units and Claimant 2 one of its generating units, to respond to AEMO's *directions* and in turn incurred costs. In line with the intervention settlement timetable, AEMO calculated *directed participant* compensation and notified the *directed participants* of the compensation payable.

Table 1 Summary of directions for Claimant 1

Directed unit	Issue time	Effective date/time	End date/time	Reason
Unit 1	25/01/2021 16:53	26/01/2021 01:00	27/01/2021 17:00	System strength
Unit 2	25/01/2021 16:53	26/01/2021 1:30	26/01/2021 11:30	System strength
Unit 2	26/01/2021 15:30	27/01/2021 00:00	28/01/2021 11:00	System strength
Unit 1	29/01/2021 09:30	29/01/2021 12:00	1/02/2021 04:00	System strength
Unit 1	31/01/2021 17:00	1/02/2021 08:30	3/02/2021 04:00	System strength
Unit 2	2/02/2021 17:00	3/02/2021 04:00	3/02/2021 16:00	System strength
Unit 2	3/02/2021 17:00	4/02/2021 2:30	4/02/2021 9:15	System strength
Unit 2	4/02/2021 10:30	5/02/2021 00:00	9/02/2021 04:00	System strength
Unit 1	4/02/2021 14:30	4/02/2021 22:30	6/02/2021 20:00	System strength
Unit 2	12/02/2021 12:45	12/02/2021 16:00	15/02/2021 12:00	System strength
Unit 1	13/02/2021 17:00	14/02/2021 08:00	15/02/2021 10:30	System strength
Unit 4	17/02/2021 21:00	18/02/2021 22:00	19/02/2021 10:30	System strength
Unit 2	17/02/2021 21:00	19/02/2021 00:30	19/02/2021 10:30	System strength
Unit 3	20/02/2021 17:30	21/02/2021 10:00	24/02/2021 04:00	System strength
Unit 1	22/02/2021 16:00	23/02/2021 00:00	25/02/2021 04:00	System strength
Unit 1	24/02/2021 14:00	25/02/2021 05:00	25/02/2021 18:00	System strength
Unit 2	24/02/2021 14:00	25/02/2021 09:30	25/02/2021 18:30	System strength

Source: AEMO

Table 2 Summary of directions for Claimant 2

Directed unit	Issue date/time	Effective date/time	Cancellation time	Reason
Unit 5	28/01/2021 08:50	28/01/2021 08:50	28/01/2021 10:30	System strength

Source: AEMO

As *directed participants*, the two market participants are entitled to compensation under clause 3.15.7 of the NER, which sets out compensation based upon:

- the amount of the relevant market service which the *directed participant* has been enabled to provide in response to the *direction*; and
- the 90th percentile price of the relevant market service over the preceding 12 months.

Both Claimant 1 and Claimant 2 have made claims for additional compensation.

2.1.1 Managing system strength

Following changes to the NER in 2017[1], the South Australian region faces system strength issues (i.e., adequate fault currents) that are being and/or will be principally managed by:

- AEMO identifying fault level shortfalls at critical nodes in the network;
- Transmission Network Service Providers (TNSPs) performing the role of system strength service provider, with responsibility to procure system strength services, including from scheduled generators, to address fault level shortfalls as determined by AEMO; and
- AEMO directing specific scheduled generators to synchronise or remain online where necessary to ensure adequate system strength is maintained.

While these arrangements may in time prove sufficient to ensure system strength requirements are met in the future, the process of TNSPs procuring system strength services remains ongoing[2]. In the meantime, AEMO has been ensuring adequate fault levels are maintained by applying operational procedures regarding permissible combinations of generators. Where the optimal supply solution determined by the NEM dispatch engine (NEMDE) is inconsistent with these permissible combinations, AEMO

[1] AEMC (2017) *National Electricity Amendment (Managing power system fault levels) Rule 2017*, 19 September.

[2] For instance, in South Australia, ElectraNet is in the process of commissioning two synchronous condensers at Davenport substation (to be in service by July 2021) and two at Robertstown substation (expected to be ready for operation before the end of June 2021). See https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

over-rides the solution and directs specific generators to ensure a permissible combination of generators.

2.2 Clause 3.15.7

AEMO must compensate each *directed participant* for the provision of energy or market ancillary services pursuant to a direction to be determined in accordance with the following formula:

$$DCP = AMP * DQ$$

Where:

- DCP is the amount of compensation the *directed participant* is entitled to receive.[3]
- AMP is the price below which are 90% of the spot prices or ancillary service prices (as the case may be) for the relevant service provided by Scheduled Generators, Semi-Scheduled Generators, Scheduled Network Service Providers or Market Customers in the region to which the direction relates, for the 12 months immediately preceding the trading day in which the direction was issued.

DQ is either:

(a) the difference between the total adjusted gross energy delivered or consumed by the *directed participant* and the total adjusted gross energy that would have been delivered or consumed by the *directed participant* had the direction not been issued; or

(b) the amount of the relevant market ancillary service which the *directed participant* has been enabled to provide in response to the direction.

2.3 Clause 3.15.7B(a)

A *directed participant* that is entitled to compensation under clause 3.15.7 and 3.15.7A may make a claim for additional compensation under clause 3.15.7B, which confines compensation (under clause 3.15.7B (a)) to:

1. the aggregate of the loss of revenue and additional net direct costs incurred by the *directed participant* in respect of a scheduled generating unit, semi-scheduled generating unit or scheduled network services, as the case may be, as a result of the provision of the service under direction; less

[3] DCP is calculated in accordance with NER Clause 3.15.7(c).

2. the amount notified to that *directed participant* pursuant to clause 3.15.7(c) or clause 3.15.7A(f); less

3. the aggregate amount the *directed participant* is entitled to receive in accordance with clause 3.15.6(c) for the provision of a service rendered as a result of the direction.

In broad terms, clause 3.15.7B (a) entitles a *directed participant* to claim compensation to cover loss of revenue and net direct costs minus *trading amounts* for *energy* and *market ancillary services* and minus any compensation for directed services that has been determined.

The *directed participants* in this case have made claims for compensation for additional net direct costs pursuant to clause 3.15.7B (a)(1) arising from their responses to *direction*s issued between 25 January and 25 February 2021.

3 The directions and initial compensation

3.1 Claim 1 *directions*

3.1.1 Details of the *directions*

Regarding Claim 1, AEMO issued the following *directions* starting 25 January and ending 25 February 2021.

Table 3 AEMO's *directions* 25 January to 25 February 2021

Directed unit	Event Number	Issued date/time	Effective date/time	End date/time	Reason
Unit 1	1-1	25/01/2021 16:53	26/01/2021 01:00	27/01/2021 17:00	System strength
Unit 2	1-1	25/01/2021 16:53	26/01/2021 1:30	26/01/2021 11:30	System strength
Unit 2	1-2	26/01/2021 15:30	27/01/2021 00:00	28/01/2021 11:00	System strength
Unit 1	2-1	29/01/2021 09:30	29/01/2021 12:00	1/02/2021 04:00	System strength
Unit 1	3-1	31/01/2021 17:00	1/02/2021 08:30	3/02/2021 04:00	System strength
Unit 2	3-1	2/02/2021 17:00	3/02/2021 04:00	3/02/2021 16:00	System strength
Unit 2	4-1	3/02/2021 17:00	4/02/2021 2:30	4/02/2021 9:15	System strength
Unit 2	1-1	4/02/2021 10:30	5/02/2021 00:00	9/02/2021 04:00	System strength
Unit 1	1-1	4/02/2021 14:30	4/02/2021 22:30	6/02/2021 20:00	System strength
Unit 2	1-1	12/02/2021 12:45	12/02/2021 16:00	15/02/2021 12:00	System strength
Unit 1	1-1	13/02/2021 17:00	14/02/2021 08:00	15/02/2021 10:30	System strength
Unit 4	2-1	17/02/2021 21:00	18/02/2021 22:00	19/02/2021 10:30	System strength
Unit 2	2-1	17/02/2021 21:00	19/02/2021 00:30	19/02/2021 10:30	System strength
Unit 3	1-1	20/02/2021 17:30	21/02/2021 10:00	24/02/2021 04:00	System strength
Unit 1	1-1	22/02/2021 16:00	23/02/2021 00:00	25/02/2021 04:00	System strength
Unit 1	2-1	24/02/2021 14:00	25/02/2021 05:00	25/02/2021 18:00	System strength
Unit 2	2-1	24/02/2021 14:00	25/02/2021 09:30	25/02/2021 18:30	System strength

Source: AEMO

3.1.2 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the above *directions* as summarised in Table 4.

Table 4 AEMO's settlement compensation amounts in respect of Claim 1 *directions*

Directed unit	Event number	Issued date/time	Final billing statement	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 1	1-1	25/01/2021 16:53	24/02/2021	$98,721	$14,700	$10,388
Unit 2	1-1	25/01/2021 16:53	24/02/2021	$25,088	$3,403	$95,318
Unit 2	1-2	26/01/2021 15:30	24/02/2021	$88,603	$12,159	$76,444

Directed unit	Event number	Issued date/time	Final billing statement	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 1	2-1	29/01/2021 09:30	24/02/2021; 03/03/2021	$159,151	$48,382	$110,768
Unit 1	3-1	31/01/2021 17:00	03/03/2021	$107,504	-$1,888	$109,391
Unit 2	3-1	2/02/2021 17:00	03/03/2021	$29,653	$9,046	$20,607
Unit 2	4-1	3/02/2021 17:00	03/03/2021	$17,002	$11,687	$5,315
Unit 2	1-1	4/02/2021 10:30	03/03/2021; 10/03/2021	$248,228	$1,042	$247,186
Unit 1	1-1	4/02/2021 14:30	03/03/2021	$109,434	-$23,178	$132,611
Unit 2	1-1	12/02/2021 12:45	10/03/2021; 17/03/2021	$166,464	$28,832	$137,631
Unit 1	1-1	13/02/2021 17:00	10/03/2021; 17/03/2021	$62,725	-$3,085	$65,810
Unit 4	2-1	17/02/2021 21:00	17/03/2021	$27,667	$6,593	$21,073
Unit 2	2-1	17/02/2021 21:00	17/03/2021	$24,553	$5,220	$19,333
Unit 3	1-1	20/02/2021 17:30	17/03/2021; 24/03/2021	$159,260	$11,964	$147,296
Unit 1	1-1	22/02/2021 16:00	24/03/2021	$125,766	$36,167	$89,599
Unit 1	2-1	24/02/2021 14:00	24/03/2021	$31,520	$889	$30,631
Unit 2	2-1	24/02/2021 14:00	24/03/2021	$20,545	-$7,824	$28,368

Source: AEMO

The amount of compensation a *directed participant* is entitled to receive (DCP) is calculated in accordance with Clause 3.15.7(c) of the NER. The Retained Trading Amount (RTA) is calculated in accordance with Clause 3.15.6(b) for the additional energy produced, which would have been included in the settlement amount indicated in the Preliminary Billing statement. Since invoices are issued weekly and the intervention period spanned two billing weeks, the compensation calculations for both units are presented in two parts – one for each relevant billing week.

Provisional Settlement Compensation is determined as DCP minus RTA and included in the Final Billing statement.

3.2 Claim 2 *directions*

3.2.1 Details of the *directions*

Regarding Claim 2, AEMO issued the following *direction* on 28 January 2021.

Table 5 AEMO's *directions* on 28 January 2021

Directed unit	Event Number	Issued date/time	Effective datetime	End datetime	Reason
Unit 5	1-1	28/01/2021 08:50	28/01/2021 08:50	28/01/2021 10:30	System strength

Source: AEMO

3.2.2 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the above *directions* as summarised in Table 6.

Table 6 AEMO's settlement compensation amounts in respect of Claim 2 *direction*

Directed unit	Event Number	Issued date/time	Final billing statement	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 5	1-1	28/01/2021, 08:50	24/02/2021	$2,736	$1,502	$1,234

Source: AEMO

4 Claims for additional compensation

4.1 Additional compensation in respect of Claim 1

Claimant *1* has submitted the following claims for additional compensation for the directions as a *directed participant*.

In addition to the claims set out in the table below, two other claims were also made, however, these were not assessed as part of this determination as any claims under $20,000 are not required to be assessed by an independent expert under clause 3.12.2(l)(2) of the NER.

Table 7 Summary of additional compensation claim estimates in respect of Claim 1

Directed unit	Event number	Issue date/time	Gas costs	Start cost	Contingency raise recovery cost	Variable operating & maintenance (VOM)	Overtime	Cost of Direction (COD)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
Unit 1	1-1	25/01/2021 16:53	$135,358	-	$250	$4,852	-	$140,460	$98,721	$41,739
Unit 2	1-2	26/01/2021 15:30	$124,760	-	$179	$4,246	-	$129,185	$88,603	$40,582
Unit 1	2-1	29/01/2021 09:30	$216,404	-	$236	$7,764	-	$224,404	$159,151	$65,253
Unit 1	3-1	31/01/2021 17:00	$195,852	-	$153	$5,277	-	$201,282	$107,504	$93,778
Unit 2	3-1	2/02/2021 17:00	$55,247	-	$42	$1,456	-	$56,745	$29,653	$27,092
Unit 2	1-1	4/02/2021 10:30	$451,583	-	$450	$12,131	-	$464,164	$248,228	$215,936
Unit 1	1-1	4/02/2021 14:30	$208,517	-	$220	$5,520	-	$214,257	$109,434	$104,823
Unit 2	1-1	12/02/2021 12:45	$315,684	-	$513	$8,249	-	$324,446	$166,464	$157,982
Unit 1	1-1	13/02/2021 17:00	$124,421	-	$167	$3,215	-	$127,803	$62,725	$65,078
Unit 4	2-1	17/02/2021 21:00	$51,978	$22,423	$63	$1,516	$4,582	$80,562	$27,667	$52,895
Unit 2	2-1	17/02/2021 21:00	$45,642	-	$46	$1,213	-	$46,901	$24,553	$22,348
Unit 3	1-1	20/02/2021 17:30	$302,261	-	$122	$3,033	-	$305,415	$159,260	$146,155
Unit 1	1-1	22/02/2021 16:00	$236,650	-	$175	$4,064	-	$240,889	$125,766	$115,122
Unit 1	2-1	24/02/2021 14:00	$56,977	-	$89	$1,577	-	$58,643	$31,520	$27,123
Unit 2	2-1	24/02/2021 14:00	$37,836	$14,630	$56	$1,092	-	$53,613	$20,545	$33,068

Note: Add comp values may not sum perfectly due to rounding errors

Source: Claimant 1.

4.2 Additional compensation in respect of Claim 2

Claimant 2 has submitted the following claims for additional compensation for the directions as a *directed participant*.

Table 8 Summary of additional compensation claim in respect of Claim 2

Item	Costs
Gas cost	$6,689.57
Equivalent Operating Hours (EOH) cost	$24,196.40
Other costs (transportation costs & FCAS)	$848.76
Cost of Direction (COD)	***$31,734.77***
Compensation entitlement (DCP)	$2,736
Additional compensation amount (COD-DCP)	**$28,999.20**

Note: Add comp value may not sum perfectly due to rounding errors.
Source: Claimant 2.

Claimant 2 initially also included debt interest costs, however the participant agreed to withdraw this part of the claim.

4.3 Total additional compensation claimed

Table 9 Summary of total additional compensation claimed

Claim	Total additional compensation claimed
Total Claim 1	**$1,208,974**
Total Claim 2	**$28,999**

5 Synergies' assessment regarding Claim 1

This section analyses the reasonableness of the additional compensation claims and sets out Synergies' final position on each component of Claim 1.

5.1 Gas fuel cost

5.1.1 Calculation method

The Claimant's method to calculate the additional gas costs is as follows:

- The Claimant derived a weighted average gas price by combining gas supplied under two gas contracts according to the total gas taken under each contract and the price set for each contract.
- The Claimant then recorded the contribution of the relevant generating unit to the total power station output, based on target outputs[4].
- The generating unit's proportional share of total power station output was multiplied by the power station's total gas consumption for that interval from under each of the two gas pipeline contracts.
- Finally, the generating unit's total allocated quantity of gas was multiplied by the average gas price across both contracts.

5.1.2 Approach to calculating costs

It appears the cost of the gas used to comply with the *directions* could be lower, had all the required gas been sourced from the Claimant's gas pipeline contract with the lower price (gas supply for the affected generation units is sourced via two different pipelines under two different contracts).

In a previous determination, the Claimant had advised that it operates the power station maintaining a degree of redundancy in the fuel supply by continually taking gas supply from two pipelines, whenever possible. This is part of the reason why gas is continuously observed to be drawn from both contracts during the *direction* and not solely from under the cheapest of the two contracts.

In this previous determination, Synergies also raised the question whether part or all of the gas supplied under a take-or-pay contract should be treated as a sunk cost.

[4] While we are unclear as to why this calculation should use target instead of actual outputs, the choice of input makes limited difference to the final result.

Our decisions on each of these issues is explained below.

Re-calculated gas costs

Synergies replicated the Claimant's gas cost approach above but took a slightly different approach of using the separate gas contract prices and calculating generator unit proportional shares of the gas supplied in each contract for each interval. This better reflects the intent of the NER, in our view.

The Claimant's method produces small distortions in the allocation of gas costs between generating units, where the relative share of consumption varies between intervals. Our method avoids this, by calculating the quantities under each contract separately before applying the contract-specific price and repeating this for each interval. The differences between the two approaches are modest, as shown in Table 10.

This is the approach taken by Synergies in a previous compensation determination of the Claimant's gas costs claim.

An additional minor modification to the calculation was also made based on a unit calculation error. The Claimant subtracted the gas used by a separate generating unit while it was operating simultaneously with the directed unit but made a small error in calculating this amount. Synergies has rectified this, and the modification contributes to a small reduction in the amount of additional compensation allowed.

Table 10 Summary of total gas costs claimed versus Synergies' estimate

Unit	Event number	Direction date/time	Total gas cost (as claimed)	Total gas cost (Synergies' calculation)	Difference
Unit 1	1-1	25/01/2021 16:53	$135,358	$129,822	-$5,536
Unit 2	1-2	26/01/2021 15:30	$124,760	$116,130	-$8,630
Unit 1	2-1	29/01/2021 09:30	$216,404	$206,021	-$10,383
Unit 1	3-1	31/01/2021 17:00	$195,852	$194,679	-$1,173
Unit 2	3-1	2/02/2021 17:00	$55,247	$55,251	$4
Unit 2	1-1	4/02/2021 10:30	$451,583	$451,581	-$2
Unit 1	1-1	4/02/2021 14:30	$208,517	$211,732	$3,215
Unit 2	1-1	12/02/2021 12:45	$315,684	$312,326	-$3,358
Unit 1	1-1	13/02/2021 17:00	$124,421	$124,421	$0
Unit 4	2-1	17/02/2021 21:00	$51,978	$51,942	-$36
Unit 2	2-1	17/02/2021 21:00	$45,642	$45,654	$12
Unit 3	1-1	20/02/2021 17:30	$302,261	$302,083	-$178
Unit 1	1-1	22/02/2021 16:00	$236,650	$230,369	-$6,281
Unit 1	2-1	24/02/2021 14:00	$56,977	$55,343	-$1,634
Unit 2	2-1	24/02/2021 14:00	$37,836	$37,790	-$46

Not a sunk cost

The Claimant confirmed that it had the flexibility to take receipt of the gas at delivery points besides the generation units in question. The Claimant's gas trading desk allocates gas from its portfolio to a wide range of delivery points throughout the day, having scope, in theory, to allocate gas to its highest value uses (internal to the business) on any given day across multiple regions in the NEM.

In line with our previous determination, we accept that the Claimant's gas costs should not be treated as a sunk cost.

5.2 Start cost

Start costs were claimed for Unit 4 for directions received on 17 Feb 2021 and for Unit 2 for directions received on 24 February 2021.

The Claimant's method for calculating the start costs is as follows:

- The Claimant identified the type of start as being a cold start following a period off-line of duration greater than 90 hours.
- The Claimant then took a historical estimate of the cost of a cold start and adjusted the estimate for inflation by using an approximate annual inflation rate of 2.5%.
- To derive the final start cost, the cost of electricity for internal loads (priced at the average market price over the start-up period) was added to the cost of fuel to heat the generator (priced at the same weighted average price used for the gas costs in a single price interval – "blended gas cost").

The costs were supported by a confidential report provided by the Claimant.

Synergies accepts the start cost estimates, calculated using the blended gas price method used by the Claimant in its claim for additional compensation.

5.3 Variable operating and maintenance (VOM) costs

The Claimant's method to calculate the VOM costs was as follows:

- A per interval VOM cost was calculated based on a historical estimate and was then adjusted for inflation by using an annual inflation rate of 2.5%.
- The VOM rate was applied to every interval that each unit was operating under AEMO's direction.

- Then, the half hourly VOM costs were summed across the period for which each generating unit was operating under direction.

The unit VOM values were supported by a confidential report provided by the Claimant.

The VOM costs identified by the Claimant relate to the operating and maintenance costs driven by the hours of operation of the plant. VOM costs can only be considered avoidable costs (i.e., costs incurred as a result of the *directions*) if there is clear evidence that the generating units would have been off-line but for the *directions*. The need for the *direction* arose from AEMO's consideration of forecasts of plant dispatch based on forecast demand and the prices that generation was being bid in future periods. As per previous similar determinations, Synergies has assumed that the directed generating units would not have been in operation during the directed periods but for the *directions*.

On the basis of the above, we accept the inclusion of VOM costs for all units as calculated by the Claimant.

5.4 Contingency raise costs

The Claimant's method to calculate the additional costs incurred as a result of its increased Frequency Control Ancillary Service (FCAS) Raise liabilities (i.e., the costs recovered from the Claimant in respect of contingency Raise costs, allocated in accordance with the FCAS causer pays formulation) is as follows:

- The Claimant first determined the total liability of the power station in respect of contingency FCAS Raise services (i.e., to pay for 6-second, 60-second and 5-minute FCAS Raise services).
- The Claimant then determined the total contribution of the units to the total power station output during the relevant period, based on target outputs[5].
- Next, the generating unit's proportional share of power station output was multiplied by the power station's total FCAS raise liability for that interval.
- Finally, this value was summed for the period.

The Claimant's supporting evidence shows workings and detailed FCAS cost assumptions for the power station. We found this methodology reasonable, subject to the figures reflecting a correct interpretation of the FCAS cost allocation rules (which we

[5] While we are unclear as to why this calculation should use target instead of actual outputs, the choice of input makes little difference to the final result.

have not assessed because the FCAS costs constitute a very minor component of the total claimed costs).

Synergies has verified these data by collecting FCAS Raise unit costs from AEMO, and as such allows this element of the compensation claim.

5.5 Overtime Cost

As a result of the *direction* on 18 February 2021, an overtime cost associated with additional staffing requirements to respond to the *direction* was claimed for the operations of Unit 4. This cost was supported by further evidence provided by the Claimant following the Draft Determination.

Overtime costs were calculated based on the hourly rate (converted from the staff member's annual salary and doubled for overtime) multiplied by the hours of the shift in which the staff member was required to operate the Unit for the direction.

We acknowledge that an unscheduled start can cause additional labour costs and that clause 3.15.7B(a3)(3) explicitly provides for incremental "manning" costs to be included in net direct costs.

We have deemed the additional staffing arrangements to be reasonable and the calculation of overtime staffing costs acceptable. As such, we have allowed these costs for the final determination.

5.6 Claim 1 results

Our assessment of the Claimant's total claimed costs is summarised in the tables below. In summary, Synergies has accepted most of the additional compensation claimed by the Claimant, with some modification to the gas cost compensation amounts.

Table 11 Unit 1 (25 January 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$135,358	$129,822	-$5,536
Start cost	$0	$0	$0
VOM	$4,852	$4,852	$0
FCAS	$250	$250	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$140,460	$134,924	-$5,536
Compensation entitlement (DCP)	$98,721	$98,721	$0
Additional compensation amount (COD-DCP)	**$41,739**	**$36,203**	**-$5,536**

Source: Claimant 1, Synergies.

Table 12 Unit 2 (26 January 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$124,760	$116,130	-$8,630
Start cost	$0	$0	$0
VOM	$4,246	$4,246	$0
FCAS	$179	$179	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$129,185	$120,555	-$8,630
Compensation entitlement (DCP)	$88,603	$88,603	$0
Additional compensation amount (COD-DCP)	**$40,582**	**$31,952**	**-$8,630**

Source: Claimant 1, Synergies.

Table 13 Unit 1 (29 January 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$216,404	$206,021	-$10,383
Start cost	$0	$0	$0
VOM	$7,764	$7,764	$0
FCAS	$236	$236	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$224,404	$214,021	-$10,383
Compensation entitlement (DCP)	$159,151	$159,151	$0
Additional compensation amount (COD-DCP)	**$65,253**	**$54,870**	**-$10,383**

Source: Claimant 1, Synergies.

Table 14 Unit 1 (31 January 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$195,852	$194,679	-$1,173
Start cost	$0	$0	$0
VOM	$5,277	$5,277	$0
FCAS	$153	$153	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$201,282	$200,109	-$1,173
Compensation entitlement (DCP)	$107,504	$107,504	$0
Additional compensation amount (COD-DCP)	**$93,778**	**$92,605**	**-$1,173**

Source: Claimant 1, Synergies.

Table 15 Unit 2 (2 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$55,247	$55,251	$4

Item	Costs claimed	Synergies' determination	Difference
Start cost	$0	$0	$0
VOM	$1,456	$1,456	$0
FCAS	$42	$42	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$56,745	$56,749	$4
Compensation entitlement (DCP)	$29,653	$29,653	$0
Additional compensation amount (COD-DCP)	**$27,092**	**$27,096**	**$4**

Source: Claimant 1, Synergies.

Table 16 Unit 2 (4 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$451,583	$451,581	-$2
Start cost	$0	$0	$0
VOM	$12,131	$12,131	$0
FCAS	$450	$450	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$464,164	$464,162	-$2
Compensation entitlement (DCP)	$248,228	$248,228	$0
Additional compensation amount (COD-DCP)	**$215,936**	**$215,934**	**-$2**

Source: Claimant 1, Synergies.

Table 17 Unit 1 (4 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$208,517	$211,732	$3,215
Start cost	$0	$0	$0
VOM	$5,520	$5,520	$0
FCAS	$220	$220	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$214,257	$217,472	$3,215
Compensation entitlement (DCP)	$109,434	$109,434	$0
Additional compensation amount (COD-DCP)	**$104,823**	**$108,038**	**$3,215**

Source: Claimant 1, Synergies.

Table 18 Unit 2 (12 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$315,684	$312,326	-$3,358
Start cost	$0	$0	$0
VOM	$8,249	$8,249	$0

Item	Costs claimed	Synergies' determination	Difference
FCAS	$513	$513	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$324,446	$321,088	-$3,358
Compensation entitlement (DCP)	$166,464	$166,464	$0
Additional compensation amount (COD-DCP)	**$157,982**	**$154,624**	**-$3,358**

Source: Claimant 1, Synergies.

Table 19 Unit 1 (13 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$124,421	$124,421	$0
Start cost	$0	$0	$0
VOM	$3,215	$3,215	$0
FCAS	$167	$167	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$127,803	$127,803	$0
Compensation entitlement (DCP)	$62,725	$62,725	$0
Additional compensation amount (COD-DCP)	**$65,078**	**$65,078**	**$0**

Source: Claimant 1, Synergies.

Table 20 Unit 4 (17 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$51,978	$51,942	-$36
Start cost	$22,423	$22,423	$0
VOM	$1,516	$1,516	$0
FCAS	$63	$63	$0
Overtime	$4,582	$4,582	$0
Cost of Direction (COD)	$80,562	$80,526	-$36
Compensation entitlement (DCP)	$27,667	$27,667	$0
Additional compensation amount (COD-DCP)	**$52,895**	**$52,859**	**-$36**

Source: Claimant 1, Synergies.

Table 21 Unit 2 (17 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$45,642	$45,654	$12
Start cost	$0	$0	$0
VOM	$1,213	$1,213	$0
FCAS	$46	$46	$0
Overtime	$0	$0	$0

Item	Costs claimed	Synergies' determination	Difference
Cost of Direction (COD)	$46,901	$46,913	$12
Compensation entitlement (DCP)	$24,553	$24,553	$0
Additional compensation amount (COD-DCP)	**$22,348**	**$22,360**	**$12**

Source: Claimant 1, Synergies.

Table 22 Unit 3 (20 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$302,261	$302,083	-$178
Start cost	$0	$0	$0
VOM	$3,033	$3,033	$0
FCAS	$122	$122	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$305,415	$305,238	-$177
Compensation entitlement (DCP)	$159,260	$159,260	$0
Additional compensation amount (COD-DCP)	**$146,155**	**$145,978**	**-$177**

Source: Claimant 1, Synergies.

Table 23 Unit 1 (22 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$236,650	$230,369	-$6,281
Start cost	$0	$0	$0
VOM	$4,064	$4,064	$0
FCAS	$175	$175	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$240,889	$234,607	-$6,281
Compensation entitlement (DCP)	$125,766	$125,766	$0
Additional compensation amount (COD-DCP)	**$115,122**	**$108,841**	**-$6,281**

Source: Claimant 1, Synergies.

Table 24 Unit 1 (24 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$56,977	$55,343	-$1,634
Start cost	$0	$0	$0
VOM	$1,577	$1,577	$0
FCAS	$89	$89	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$58,643	$57,009	-$1,634
Compensation entitlement (DCP)	$31,520	$31,520	$0

Item	Costs claimed	Synergies' determination	Difference
Additional compensation amount (COD-DCP)	**$27,123**	**$25,489**	**-$1,634**

Source: Claimant 1, Synergies.

Table 25 Unit 2 (22 February 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$37,836	$37,790	-$46
Start cost	$14,630	$14,630	$0
VOM	$1,092	$1,092	$0
FCAS	$56	$56	$0
Overtime	$0	$0	$0
Cost of Direction (COD)	$53,613	$53,567	-$46
Compensation entitlement (DCP)	$20,545	$20,545	$0
Additional compensation amount (COD-DCP)	**$33,068**	**$33,022**	**-$46**

Source: Claimant 1, Synergies.

6 Synergies' assessment of Claim 2

This section analyses the reasonableness of the additional compensation claims and sets out Synergies' final position on each component of Claim 2.

6.1 Gas fuel cost

6.1.1 Quantity of gas burned

Based on the gas invoice from the gas supplier that was provided by the Claimant, Synergies accepts the quantity of gas burned by the Claimant's plant during the *direction* period.

6.1.2 Calculation method

The Claimant incurred its gas costs under a gas sales and transportation agreement it has with its related party. The Claimant's method to calculate the additional gas costs was based on the price at which gas was supplied during the *direction* period multiplied by the amount of gas used during that period.

The details of the transaction relevant to the *direction* period were contained in an invoice provided by the Claimant, and we accept the calculation of gas costs as the price at which the gas was purchased from the supplier.

6.2 Transportation cost

The Claimant incurred costs under its gas sales and transportation agreement with its related party noted above. The details of its transportation costs were separately recorded on the invoice provided by the Claimant. These included a cost per unit charge for gas delivery which was multiplied by the amount of gas supplied.

In the draft determination, Synergies accepted both the calculation method and the quantities claimed. We remain of this view and therefore, for our final determination, Synergies has decided to allow this element of the compensation claim.

6.3 Frequency Control Ancillary Services (FCAS)

Under previous independent expert determinations, FCAS Charges have been explicitly recognised and accepted as a valid component of a claim. The Claimant incurred FCAS costs as result of the direction and calculated these by summing each contingency Raise service provided by the Claimant during the *direction* period. The Claimant's supporting evidence shows workings and FCAS cost assumptions for the power station.

Synergies verified these data for the draft determination by collecting FCAS Raise unit costs from AEMO and as such accepts them for the final determination.

6.4 Equivalent operating hours (EOH)

6.4.1 EOH explanation

The Claimant grouped both start costs and variable operating and maintenance (VOM) costs under the heading equivalent operating hours (EOH). While the Claimant ultimately included some costs within its EOH calculation that related to other types of costs, the concept is primarily concerned with estimating operating and maintenance costs arising from activities including, but not limited to, running the plant.

The Claimant's generating plant incurs wear-and-tear during use that requires it to undertake prescribed maintenance activities after a certain number of hours of operation[6]. The maintenance costs associated with a given maintenance procedure are divided by the number of hours for which the plant operates before needing that maintenance procedure. This then is taken to be the unit maintenance cost per hour of operation[7].

The unit cost of maintenance per hour of operation is also used as a standard cost unit from which costs with other drivers can be estimated. In particular, Claimant 2 derives the unit cost of each generator start by expressing the wear and tear arising from a start in terms of the EOH per start, which can then be costed at the unit cost rate derived for an hour of operation.

For example, if the plant required a $300,000 maintenance procedure after every 1,000 hours of use and a $1,000,000 procedure after 5,000 hours of use, the EOH would be equal to $300,000/1,000 plus $1,000,000/5,000, equalling $500 per hour. If a start imposed wear and tear on a generating unit equivalent to 20 hours of operation, then the maintenance cost of a start would equal 20 hours * $500/hour or $10,000.

6 The main source of wear-and-tear incurred by gas generator is the fracturing of the turbine fins caused by the expansion of metal due to changes in temperature. This metal fatigue develops as a result of operation and develops more rapidly where the rate of temperature change is faster. Thus, the wear caused by steady operation is less than that associated with starting, stopping and rapidly accelerating or decelerating.

7 For some maintenance procedures, the trigger may be the production of some cumulative amount of energy and the associated unit cost is derived by the same procedure (cost of procedure/MWh produced between procedures).

6.4.2 Start cost

The start cost was based on the recommendation from the original equipment manufacturer (OEM) that start-up costs for the relevant generating plant should be a certain number of EOH. The other relevant information pertaining to these figures was provided confidentially by the Claimant to Synergies. On this basis, the EOH calculation for the start costs incurred due to the *direction* is accepted by Synergies in our final determination.

6.4.3 Variable operating and maintenance costs

The Claimant incurred two types of variable operating and maintenance costs because of the *direction*. The first type is driven by hours of operation. This component of the claim used the same cost per hour used in the EOH calculation of start costs. That unit cost was multiplied by the number of hours for which the plant was synchronised under *direction*.[8]

The second cost was calculated on a per megawatt basis. This was determined by the Claimant by dividing the annual cost of the relevant maintenance items (ie. those maintenance items driven by energy produced), by the annual generating output of the relevant plant. The resulting unit cost was then multiplied by the energy produced by the plant during the *direction* period.[9]

Both of these costs were determined using expert evaluations and historical data. Synergies reviewed these claims and the supporting evidence for the draft determination and has accepted the costs based on the information provided. We remain of this view and therefore, for our final determination, Synergies has decided to allow this element of the compensation claim.

6.5 Claim 2 results

Our assessment of the Claimant's total claimed costs is summarised in Table 26. In summary, Synergies has accepted all the additional compensation claimed by the Claimant.

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[8] Note that this figure is slightly different from the start cost EOH, as start-up costs also incur costs such as diesel to start the turbine.

[9] Note that this calculation was included by the Claimant within their EOH costs for the convenience of reporting the cost of a start.

Table 26 Claim 2 final compensation allowed

Item	Costs claimed	Synergies' determination
Gas cost	$6,689.57	$6,689.57
Equivalent Operating Hours (EOH) cost	$24,196.40	$24,196.40
Other costs (transportation costs & FCAS)	$848.76	$848.76
Cost of Direction (COD)	***$31,734.77***	***$31,734.77***
Compensation entitlement (DCP)	$2,736	$2,736
Additional compensation amount (COD-DCP)	**$28,999.20**	**$28,999.20**

Note: Add comp value may not sum perfectly due to rounding errors.

Source: Claimant 2, Synergies.

7 Conclusion

In this final determination, Synergies concludes as follows.

- Claimant *1*'s costs to comply with the *direction* are slightly less than claimed, due to Synergies adopting a slightly different approach to calculating gas fuel costs. On this basis, Claimant 1 is entitled to additional compensation of $1,174,948.
- Claimant *2*'s costs to comply with the *direction* are as claimed and is entitled to additional compensation of $28,999.20.

The *directed participants* have been informed of these final determinations, the reasons for them, and the amount of compensation accepted.