Synergies
ECONOMIC CONSULTING

Additional compensation claims arising from AEMO directions during billing weeks 13 to 16
DRAFT DETERMINATION

An independent expert report for AEMO

3 August 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 three 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 draft independent expert determination be delivered no later than 3 August 2021 and a final determination by 7 October 2021. This will allow AEMO to complete the intervention settlement process by the required deadlines of 21 October, 28 October, 4 November, and 11 November 2021 for directions occurring during billing weeks 13 to 16.

In accordance with the Intervention Settlement Timetables, Synergies is issuing this draft report on 3 August 2021.

1.1 Structure of the report

In the remainder of this report, we set out the basis for our draft 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;
- Section 7 provides our analysis of the additional compensation claims for Claim 3; and
- Section 8 provides our draft 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.

The companies that have submitted a claim for additional compensation were *directed participants* on several occasions between 27 March and 20 April 2021 for the purposes of clause 3.15.7B.

During billing weeks 13 to 16, AEMO issued *directions* (Table 1) to South Australian market participants to maintain the system in a secure operating state. In response:

- Claimant 1 modified the operations of three of its generating units.
- Claimant 2 modified the operations of one of its generating units.
- Claimant 3 modified the operations of one of its generating units.

As a result of the above responses to the *directions*, each Claimant incurred costs and as a *directed participant*, is 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.

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

Directed unit	Issue time	Effective date/time	End date/time	Reason
Claim 1				
Unit 1	27/03/2021 17:40	28/03/2021 04:30	30/03/2021 17:00	System Strength
Unit 1	31/03/2021 17:00	1/04/2021 0:30	1/04/2021 16:00	System Strength
Unit 1	1/04/2021 18:00	2/04/2021 0:30	7/04/2021 16:45	System Strength
Unit 2	1/04/2021 18:00	2/04/2021 1:00	2/04/2021 17:00	System Strength
Unit 2	2/04/2021 16:00	3/04/2021 1:00	3/04/2021 17:00	System Strength

Directed unit	Issue time	Effective date/time	End date/time	Reason
Unit 2	4/04/2021 11:00	5/04/2021 0:00	6/04/2021 6:00	System Strength
Unit 2	7/04/2021 17:30	8/04/2021 4:00	8/04/2021 16:30	System Strength
Unit 2	8/04/2021 18:00	8/04/2021 22:00	9/04/2021 17:00	System Strength
Unit 1	9/04/2021 17:00	10/04/2021 1:00	11/04/2021 17:30	System Strength
Unit 2	9/04/2021 17:00	10/04/2021 1:30	11/04/2021 14:30	System Strength
Unit 3	12/04/2021 14:30	13/04/2021 0:30	14/04/2021 17:00	System Strength
Unit 1	12/04/2021 14:30	13/04/2021 14:30	14/04/2021 17:30	System Strength
Unit 2	12/04/2021 14:40	13/04/2021 0:00	14/04/2021 16:30	System Strength
Unit 3	14/04/2021 15:30	14/04/2021 22:00	15/04/2021 16:30	System Strength
Unit 2	14/04/2021 15:30	15/04/2021 0:00	15/04/2021 17:30	System Strength
Unit 3	16/04/2021 18:00	16/04/2021 22:00	17/04/2021 16:30	System Strength
Unit 3	17/04/2021 14:00	18/04/2021 00:30	18/04/2021 17:00	System strength
Unit 3	19/04/2021 17:00	20/04/2021 01:00	20/04/2021 16:00	System strength
Claim 2				
Unit 6	14/04/2021 13:45	14/04/2021 13:45	14/04/2021 16:00	System Strength
Claim 3				
Unit 7	12/04/2021 14:45	13/04/2021 14:30	14/04/2021 14:00	System Strength

Source: AEMO.

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

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

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 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] 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/.

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

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

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 during billing weeks 13 to 16.

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 28 March 2021 and ending 20 April 2021.

Table 2 AEMO's *directions* to Claimant 1

Directed unit	Event Number	Issued date/time	Effective date/time	End date/time	Reason
Unit 1	1-1	27/03/2021 17:40	28/03/2021 04:30	30/03/2021 17:00	System strength
Unit 1	3-1	31/03/2021 17:00	1/04/2021 0:30	1/04/2021 16:00	System strength
Unit 1	1-1	1/04/2021 18:00	2/04/2021 0:30	7/04/2021 16:45	System strength
Unit 2	1-1	1/04/2021 18:00	2/04/2021 1:00	2/04/2021 17:00	System strength
Unit 2	1-2	2/04/2021 16:00	3/04/2021 1:00	3/04/2021 17:00	System strength
Unit 2	1-3	4/04/2021 11:00	5/04/2021 0:00	6/04/2021 6:00	System strength
Unit 2	2-1	7/04/2021 17:30	8/04/2021 4:00	8/04/2021 16:30	System strength
Unit 2	3-1	8/04/2021 18:00	8/04/2021 22:00	9/04/2021 17:00	System strength
Unit 1	1-1	9/04/2021 17:00	10/04/2021 1:00	11/04/2021 17:30	System strength
Unit 2	1-1	9/04/2021 17:00	10/04/2021 1:30	11/04/2021 14:30	System strength
Unit 3	3-1	12/04/2021 14:30	13/04/2021 0:30	14/04/2021 17:00	System strength
Unit 1	3-1	12/04/2021 14:30	13/04/2021 14:30	14/04/2021 17:30	System strength
Unit 2	3-1	12/04/2021 14:40	13/04/2021 0:00	14/04/2021 16:30	System strength
Unit 3	4-1	14/04/2021 15:30	14/04/2021 22:00	15/04/2021 16:30	System strength
Unit 2	4-1	14/04/2021 15:30	15/04/2021 0:00	15/04/2021 17:30	System strength
Unit 3	5-2	16/04/2021 18:00	16/04/2021 22:00	17/04/2021 16:30	System strength
Unit 3	1-1	17/04/2021 14:00	18/04/2021 00:30	18/04/2021 17:00	System strength
Unit 3	2-1	19/04/2021 17:00	20/04/2021 01:00	20/04/2021 16:00	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 3 AEMO's settlement compensation amounts for Claim 1 *directions*

Directed unit	Event number	Issued date/time	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 1	1-1	27/03/2021 17:40	$150,800	$85,477	$65,323
Unit 1	3-1	31/03/2021 17:00	$38,601	$22,899	$15,703

Directed unit	Event number	Issued date/time	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 1	1-1	1/04/2021 18:00	$335,634	$151,105	$184,529
Unit 2	1-1	1/04/2021 18:00	$38,535	$10,885	$27,650
Unit 2	1-2	2/04/2021 16:00	$39,118	$249	$38,869
Unit 2	1-3	4/04/2021 11:00	$72,376	$33,697	$38,679
Unit 2	2-1	7/04/2021 17:30	$30,929	$11,684	$19,245
Unit 2	3-1	8/04/2021 18:00	$49,408	$20,269	$29,139
Unit 1	1-1	9/04/2021 17:00	$98,911	-$33,682	$132,593
Unit 2	1-1	9/04/2021 17:00	$88,219	-$33,915	$122,134
Unit 3	3-1	12/04/2021 14:30	$96,249	-$20,653	$116,902
Unit 1	3-1	12/04/2021 14:30	$64,579	-$17,019	$81,598
Unit 2	3-1	12/04/2021 14:40	$97,796	-$20,901	$118,697
Unit 3	4-1	14/04/2021 15:30	$44,856	$26,531	$18,325
Unit 2	4-1	14/04/2021 15:30	$42,506	$21,670	$20,836
Unit 3	5-2	16/04/2021 18:00	$44,081	$33,422	$10,659
Unit 3	1-1	17/04/2021 14:00	$40,152	$33,593	$6,559
Unit 3	2-1	19/04/2021 17:00	$36,726	$14,889	$21,837

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 all units are presented 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 *directions*.

Table 4 AEMO's *directions* to Claimant 2

Directed unit	Event Number	Issued date/time	Effective datetime	End datetime	Reason
Unit 6	3-1	14/04/2021 13:45	14/04/2021 13:45	14/04/2021 16:00	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 5 AEMO's settlement compensation amounts for Claim 2 *directions*

Directed unit	Event Number	Issued date/time	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 6	3-1	14/04/2021 13:45	$3,616	-$2,154	$5,771

Source: AEMO

3.3 Claim 3 *directions*

3.3.1 Details of the *directions*

Regarding Claim 3, AEMO issued the following *directions*.

Table 6 AEMO's *directions* to Claimant 3

Directed unit	Event Number	Issued date/time	Effective datetime	End datetime	Reason
Unit 7	3-1	12/04/2021 14:45	13/04/2021 14:30	14/04/2021 14:00	System Strength

Source: AEMO

3.3.2 Initial compensation

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

Table 7 AEMO's settlement compensation amounts for Claim 3 *directions*

Directed unit	Event Number	Issued date/time	Compensation entitlement (DCP)	Retained trading amounts (RTA)	Initial settlement compensation (DCP – RTA)
Unit 7	3-1	12/04/2021 14:45	$198,349	-$44,004	$242,353

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*.

Table 8 Summary of additional compensation claim estimates in respect to Claim 1

Directed unit	Event number	Direction date/time	Gas costs	Start cost	Contingency raise recovery cost	Variable operating & maintenance (VOM)	Cost of Direction (COD)	Compensation entitlement (DCP)	Add. comp amount (COD – DCP)
Unit 1	1-1	27/03/2021 17:40	$307,905	$0	$638	$1,577	$310,120	$150,800	$159,319
Unit 1	3-1	31/03/2021 17:00	$76,250	$0	$132	$1,880	$78,262	$38,601	$39,661
Unit 1	1-1	1/04/2021 18:00	$734,235	$0	$1,244	$16,559	$752,038	$335,634	$416,405
Unit 2	1-1	1/04/2021 18:00	$80,286	$0	$76	$1,941	$82,304	$38,535	$43,768
Unit 2	1-2	2/04/2021 16:00	$83,015	$0	$67	$1,941	$85,023	$39,118	$45,905
Unit 2	1-3	4/04/2021 11:00	$152,883	$11,199	$339	$3,639	$168,061	$72,376	$95,685
Unit 2	2-1	7/04/2021 17:30	$61,901	$0	$151	$1,516	$63,569	$30,929	$32,640
Unit 2	3-1	8/04/2021 18:00	$97,134	$0	$293	$2,305	$99,732	$49,408	$50,324
Unit 1	1-1	9/04/2021 17:00	$194,882	$0	$332	$4,913	$200,127	$98,911	$101,216
Unit 2	1-1	9/04/2021 17:00	$178,053	$0	$295	$4,488	$182,837	$88,219	$94,618
Unit 3	3-1	12/04/2021 14:30	$137,826	$0	$275	$4,839	$142,940	$64,579	$78,361
Unit 1	3-1	12/04/2021 14:30	$210,216	$0	$406	$4,913	$215,534	$97,796	$117,738
Unit 2	3-1	12/04/2021 14:40	$210,691	$0	$1,684	$4,913	$217,288	$96,249	$121,039
Unit 3	4-1	14/04/2021 15:30	$94,375	$0	$125	$3,136	$97,636	$42,506	$55,131
Unit 2	4-1	14/04/2021 15:30	$99,745	$0	$151	$2,244	$102,140	$44,856	$57,285
Unit 3	5-2	16/04/2021 18:00	$88,390	$0	$305	$3,315	$92,010	$44,081	$47,929
Unit 3	1-1	17/04/2021 14:00	$80,193	$0	$380	$2,957	$83,530	$40,152	$43,378
Unit 3	2-1	19/04/2021 17:00	$72,853	$0	$163	$2,688	$75,705	$36,726	$38,979
TOTAL			**$2,960,833**	**$11,199**	**$7,056**	**$69,764**	**$3,048,856**	**$1,409,476**	**$1,639,381**

Note: There may be some differences due to rounding.

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 9 Summary of additional compensation claim estimates in respect to Claim 2

Item	Costs
Gas cost	$7,814
Equivalent Operating Hours (EOH) cost	$25,465
Other costs (transportation costs & FCAS)	$1,041
Cost of Direction (COD)	***$34,320***
Compensation entitlement (DCP)	$3,616
Additional compensation amount (COD-DCP)	**$30,703**

Source: Claimant 2.

4.3 Additional compensation in respect of Claim 3

Claimant 3 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 10 Summary of additional compensation claim estimates in respect to Claim 3

Item	Costs
Gas costs	$238,567
Start costs	$21,806
Variable operating & maintenance (VOM)	$10,801
Transport	$3,287
Cost of Direction (COD)	**$274,460**
Compensation entitlement (DCP)	$198,349
Additional compensation amount (COD – DCP)	**$76,111**

Source: Claimant 3

4.4 Total additional compensation claimed

Table 11 Summary of total additional compensation claimed

Claim	Total additional compensation claimed
Total Claim 1	**$1,639,381**
Total Claim 2	**$30,703**
Total Claim 3	**$76,111**

5 Synergies' assessment regarding Claim 1

This section analyses the reasonableness of Claim 1 and sets out Synergies' draft position on each component of claimed cost.

5.1 Gas fuel cost

5.1.1 Calculation method

The Claimant applied the following method to calculate the additional gas costs for the majority (16 of 18) of its claims:

- 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.

For the remaining two claims, gas costs were calculated as follows:

- The Claimant applied the separate gas contract prices and applied them to the relevant share of gas supply in each contract for each interval.
- For these two *directions*, only one generating unit was operating therefore it was not necessary to find the proportional share of total power station output as above.

5.1.2 Synergies' approach to calculating costs

In Synergies' view, the preferred method to calculating gas costs is the second method shown above as this better reflects the intent of the NER. This is the approach taken by Synergies in a previous compensation determination of the Claimant's gas costs claim.

[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.

The Claimant's first method (which has been used in previous additional compensation claims) produces small distortions in the allocation of gas costs between generating units, where the relative share of consumption varies between intervals. The preferred 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 minor, as shown in Table 12.

Table 12 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	27/03/2021 17:40	$307,905	$307,986	$81
Unit 1	3-1	31/03/2021 17:00	$76,250	$76,249	-$1
Unit 1	1-1	1/04/2021 18:00	$734,235	$731,403	-$2,833
Unit 2	1-1	1/04/2021 18:00	$80,286	$82,816	$2,530
Unit 2	1-2	2/04/2021 16:00	$83,015	$82,990	-$25
Unit 2	1-3	4/04/2021 11:00	$152,883	$152,967	$84
Unit 2	2-1	7/04/2021 17:30	$61,901	$61,901	$0
Unit 2	3-1	8/04/2021 18:00	$97,134	$97,335	$201
Unit 1	1-1	9/04/2021 17:00	$194,882	$194,846	-$36
Unit 2	1-1	9/04/2021 17:00	$178,053	$178,053	$0
Unit 3	3-1	12/04/2021 14:30	$137,826	$137,816	-$10
Unit 1	3-1	12/04/2021 14:30	$210,216	$210,325	$109
Unit 2	3-1	12/04/2021 14:40	$210,691	$210,782	$91
Unit 3	4-1	14/04/2021 15:30	$94,375	$94,434	$59
Unit 2	4-1	14/04/2021 15:30	$99,745	$99,855	$110
Unit 3	5-2	16/04/2021 18:00	$88,390	$88,857	$467
Unit 3	1-1	17/04/2021 14:00	$80,193	$80,193	$0
Unit 3	2-1	19/04/2021 17:00	$72,853	$72,853	$0
TOTAL			**$2,960,833**	**$2,961,661**	**$828**

Source: Synergies.

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 determinations, 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 2 for directions received on 4 April 2021.

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

- The Claimant identified the start as following a period off-line of 36 hours duration.
- 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 confidential data provided by the Claimant.

Synergies accepts the start cost estimate, calculated using the blended gas price method, in the 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 VOM cost 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 is satisfied 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.

We note that the issue of VOM costs has been raised in other additional compensation claims determinations (not performed by Synergies) and whether the cost per MWh is reasonable, noting suggested VOM ranges in other sources quote lower cost per MWh. However, in our view, where the costs incurred due to a *direction* are clearly substantiated by supporting evidence, then those are in fact the costs of that business' operations, even though they might not align with figures used for planning purposes in other documentation and resources. Our interpretation of the NER is that reasonably substantiated costs, including with supporting documentation, should be approved.

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

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

5.5 Claim 1 results

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

Table 13 Unit 1 (27 March 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$307,905	$307,986	$81
Start cost	$0	$0	$0
VOM	$1,577	$1,577	$0
FCAS	$638	$638	$0
Cost of Direction (COD)	$310,120	$310,201	$81
Compensation entitlement (DCP)	$150,800	$150,800	$0
Additional compensation amount (COD-DCP)	**$159,319**	**$159,401**	**$81**

Source: Claimant 1, Synergies.

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

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$76,250	$76,249	-$1
Start cost	$0	$0	$0
VOM	$1,880	$1,880	$0
FCAS	$132	$132	$0
Cost of Direction (COD)	$78,262	$78,261	-$1
Compensation entitlement (DCP)	$38,601	$38,601	$0
Additional compensation amount (COD-DCP)	**$39,661**	**$39,660**	**$-1**

Source: Claimant 1, Synergies.

Table 15 Unit 1 (1 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$734,235	$731,403	-$2,833
Start cost	$0	$0	$0
VOM	$16,559	$16,559	$0
FCAS	$1,244	$1,244	$0
Cost of Direction (COD)	$752,038	$749,206	-$2,833
Compensation entitlement (DCP)	$335,634	$335,634	$0
Additional compensation amount (COD-DCP)	**$416,405**	**$413,572**	**-$2,833**

Source: Claimant 1, Synergies.

Table 16 Unit 2 (1 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$80,286	$82,816	$2,530
Start cost	$0	$0	$0
VOM	$1,941	$1,941	$0
FCAS	$76	$76	$0
Cost of Direction (COD)	$82,304	$84,833	$2,530
Compensation entitlement (DCP)	$38,535	$38,535	$0
Additional compensation amount (COD-DCP)	**$43,768**	**$46,298**	**$2,530**

Source: Claimant 1, Synergies.

Table 17 Unit 2 (2 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$83,015	$82,990	-$25
Start cost	$0	$0	$0
VOM	$1,941	$1,941	$0
FCAS	$67	$67	$0
Cost of Direction (COD)	$85,023	$84,998	$25
Compensation entitlement (DCP)	$39,118	$39,118	$0
Additional compensation amount (COD-DCP)	**$45,905**	**$45,880**	**$25**

Source: Claimant 1, Synergies.

Table 18 Unit 2 (4 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$152,883	$152,967	$84
Start cost	$11,199	$11,199	$0
VOM	$3,639	$3,639	$0
FCAS	$339	$339	$0
Cost of Direction (COD)	$168,061	$168,144	$84
Compensation entitlement (DCP)	$72,376	$72,376	$0
Additional compensation amount (COD-DCP)	$95,685	**$95,768**	$84

Source: Claimant 1, Synergies.

Table 19 Unit 2 (7 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$61,901	$61,901	$0
Start cost	$0	$0	$0
VOM	$1,516	$1,516	$0
FCAS	$151	$151	$0

Item	Costs claimed	Synergies' determination	Difference
Cost of Direction (COD)	$63,569	$63,569	$0
Compensation entitlement (DCP)	$30,929	$30,929	$0
Additional compensation amount (COD-DCP)	**$32,640**	**$32,640**	**$0**

Source: Claimant 1, Synergies.

Table 20 Unit 2 (8 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$97,134	$97,335	$201
Start cost	$0	$0	$0
VOM	$2,305	$2,305	$0
FCAS	$293	$293	$0
Cost of Direction (COD)	$99,732	$99,933	$201
Compensation entitlement (DCP)	$49,408	$49,408	$0
Additional compensation amount (COD-DCP)	**$50,324**	**$50,525**	**$201**

Source: Claimant 1, Synergies.

Table 21 Unit 1 (9 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$194,882	$194,846	-$36
Start cost	$0	$0	$0
VOM	$4,913	$4,913	$0
FCAS	$332	$332	$0
Cost of Direction (COD)	$200,127	$200,091	-$36
Compensation entitlement (DCP)	$98,911	$98,911	$0
Additional compensation amount (COD-DCP)	**$101,216**	**$101,108**	**-$36**

Source: Claimant 1, Synergies.

Table 22 Unit 2 (9 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$178,053	$178,053	$0
Start cost	$0	$0	$0
VOM	$4,488	$4,488	$0
FCAS	$295	$295	$0
Cost of Direction (COD)	$182,837	$182,837	$0
Compensation entitlement (DCP)	$88,219	$88,219	$0
Additional compensation amount (COD-DCP)	**$94,618**	**$94,618**	**$0**

Source: Claimant 1, Synergies.

Table 23 Unit 3 (12 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$137,826	$137,816	-$10
Start cost	$0	$0	$0
VOM	$4,839	$4,839	$0
FCAS	$275	$275	$0
Cost of Direction (COD)	$142,940	$142,930	-$10
Compensation entitlement (DCP)	$64,579	$64,579	$0
Additional compensation amount (COD-DCP)	**$78,361**	**$78,351**	**-$10**

Source: Claimant 1, Synergies.

Table 24 Unit 1 (12 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$210,216	$210,325	$109
Start cost	$0	$0	$0
VOM	$4,913	$4,913	$0
FCAS	$406	$406	$0
Cost of Direction (COD)	$215,534	$215,644	$109
Compensation entitlement (DCP)	$97,796	$97,796	$0
Additional compensation amount (COD-DCP)	**$117,738**	**$117,848**	**$109**

Source: Claimant 1, Synergies.

Table 25 Unit 2 (12 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$210,691	$210,782	$91
Start cost	$0	$0	$0
VOM	$4,913	$4,913	$0
FCAS	$1,684	$1,684	$0
Cost of Direction (COD)	$217,288	$217,379	$91
Compensation entitlement (DCP)	$96,249	$96,249	$0
Additional compensation amount (COD-DCP)	**$121,039**	**$121,130**	**$91**

Source: Claimant 1, Synergies.

Table 26 Unit 3 (14 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$94,375	$94,434	$59
Start cost	$0	$0	$0
VOM	$3,316	$3,316	$0
FCAS	$125	$125	$0

Item	Costs claimed	Synergies' determination	Difference
Cost of Direction (COD)	$97,816	$97,875	$59
Compensation entitlement (DCP)	$42,506	$42,506	$0
Additional compensation amount (COD-DCP)	**$55,131**	**$55,369**	**$59**

Source: Claimant 1, Synergies.

Table 27 Unit 2 (14 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$99,745	$99,855	$110
Start cost	$0	$0	$0
VOM	$2,244	$2,244	$0
FCAS	$151	$151	$0
Cost of Direction (COD)	$102,140	$102,250	$110
Compensation entitlement (DCP)	$44,856	$44,856	$0
Additional compensation amount (COD-DCP)	**$57,285**	**$57,394**	**$110**

Source: Claimant 1, Synergies.

Table 28 Unit 3 (16 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$88,390	$88,857	$467
Start cost	$0	$0	$0
VOM	$3,315	$3,315	$0
FCAS	$305	$305	$0
Cost of Direction (COD)	$92,010	$92,477	$467
Compensation entitlement (DCP)	$44,081	$44,081	$0
Additional compensation amount (COD-DCP)	**$47,929**	**$48,396**	**$467**

Source: Claimant 1, Synergies.

Table 29 Unit 3 (17 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$80,193	$80,193	$0
Start cost	$0	$0	$0
VOM	$2,957	$2,957	$0
FCAS	$380	$380	$0
Cost of Direction (COD)	$83,530	$83,530	$0
Compensation entitlement (DCP)	$40,152	$40,152	$0
Additional compensation amount (COD-DCP)	**$43,378**	**$43,378**	**$0**

Source: Claimant 1, Synergies.

Table 30 Unit 3 (19 April 2021) final compensation allowed

Item	Costs claimed	Synergies' determination	Difference
Gas fuel cost	$72,853	$72,853	$0
Start cost	$0	$0	$0
VOM	$2,688	$2,688	$0
FCAS	$163	$163	$0
Cost of Direction (COD)	$75,705	$75,705	$0
Compensation entitlement (DCP)	$36,726	$36,726	$0
Additional compensation amount (COD-DCP)	**$38,979**	**$38,979**	**$0**

Source: Claimant 1, Synergies.

6 Synergies' assessment regarding Claim 2

This section analyses the reasonableness of Claim 2 and sets out Synergies' draft position on each component of claimed cost.

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 accept 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 a monthly invoice provided by the Claimant.

This monthly invoice contained a break-down of the gas supplied for each day. On the day of the direction period, the 14th of April, the Claimant's plant generated electricity both for the *direction* and outside of the *direction*. The invoice did not distinguish between these two uses.

To determine what percentage of the supplied gas was used for the *direction*, the Claimant summed the total number of MWh's generated in the *direction* period and divided it by the quantity generated by the relevant plant for the whole of the 14th of April (this was obtained from AEMO data). This percentage was then multiplied by the total quantity of gas supplied to calculate the amount of gas used for the purpose of the *direction*.

Synergies accepts the calculation of gas costs at 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.

As described in the calculation of gas fuel costs, some of the gas delivered on the day of the *direction* was used separately to the *direction*. As such, the same method was used to calculate the gas transport cost for the *direction*. The quantity of gas units transported on the 14th of April was multiplied by the percentage of electricity generated for the *direction*.

Synergies accepts both the calculation method and the quantities claimed.

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 FCAS Raise unit costs for the power station incurred during the *direction*.

6.4 Equivalent operating hours (EOH)

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.

6.4.1 EOH

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[5]. 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.[6]

Confidential information on cost per hour of operation per maintenance activity was provided by the Claimant to Synergies. We accept the basis of the EOH calculations.

5 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.

6 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 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. 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.

The start cost is based on a cost per hour of operation for various maintenance activities, their interval hours and estimated cost. This cost per hour is multiplied by the original equipment manufacturer (OEM) recommended number of EOH attributable to start-up of a generating plant.

The relevant information pertaining to these figures was provided confidentially by the Claimant to Synergies.

Synergies accepts the EOH calculation for the start costs incurred due to the *direction*.

6.4.3 Variable operating and maintenance costs

The Claimant incurred variable operating and maintenance (VOM) costs because of the *direction*. The VOM costs comprise fixed dollar per hour of operation and dollar per megawatt generated. The O&M costs driven by hours of operation uses the same cost per hour applied 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*.[7]

The second component was calculated on a per megawatt basis. This was determined by the Claimant by dividing the approximate direct annual maintenance cost of relevant maintenance activities (i.e., 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.[8]

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7 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.

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

Both these costs were determined using expert evaluations and historical data. Synergies has reviewed these claims and the supporting evidence and has accepted the costs based on the information provided.

6.5 Claim 2 results

Our assessment of the Claimant's total claimed costs is summarised in Table 31. In summary, Synergies has accepted all the additional compensation claimed by the Claimant.

Table 31 Claim 2 final compensation allowed

Item	Costs claimed	Synergies' draft determination
Gas cost	$7,814	$7,814
Equivalent Operating Hours (EOH) cost	$25,465	$25,465
Other costs (transportation costs & FCAS)	$1,041	$1,041
Cost of Direction (COD)	***$34,320***	***$34,320***
Compensation entitlement (DCP)	$3,616	$3,616
Additional compensation amount (COD-DCP)	**$30,703**	**$30,703**

Source: Claimant 2, Synergies.

7 Synergies' assessment regarding Claim 3

This section analyses the reasonableness of Claim 3 and sets out Synergies' draft position on each component of claimed cost.

7.1 Gas fuel costs

The Claimant has used the following method to calculate gas fuel costs:

- The Claimant draws on several contracts for its gas supply. However, observing the physical connection of the generating unit, two relevant contracts were identified.
- One contract has a maximum daily quantity (MDQ), and as such, the maximum amount (at a higher unit price) was assumed to be taken initially, with the remainder of the *direction* volume being taken from the second contract (at a lower unit price).
- The unit price for gas was provided in invoices for each contract and volumes were presented in a spreadsheet.

While it seems that the gas volumes used to meet the *direction* were allocated arbitrarily between the two contracts, Synergies understands that determining the exact source of gas supply is difficult given the physical interconnection of the gas transmission pipelines used to deliver gas to the power station.

As the contract including the MDQ clause is take-or-pay in nature, we find it is reasonable to assume the maximum amount at the higher unit price was taken. Based on this, we accept the claimed gas fuel cost.

7.2 Start costs

The Claimant has provided an invoice presenting the start-up charge incurred for the month of April.

In reviewing the generating unit's operating hours for the month of April, Synergies noted there were four starts, however contractually only one start incurred a start-up charge as it was instigated by the Claimant due to the *direction*. The other three were undertaken as part of scheduled maintenance activities.

Synergies has reviewed the evidence supporting this and accepts that the invoiced start cost amount was incurred due to the *direction*.

7.3 Variable operating maintenance costs

The Claimant incurs a monthly VOM charge, as evidenced in a confidential invoice. To determine the proportion of the monthly charge to the *direction*, the VOM charge per fired hour was found by dividing the monthly VOM charge by the total monthly fired hours. This unit cost was then applied to the fired hours attributable to the *direction*.

Synergies has reviewed the supporting confidential documentation and accepts this as an appropriate way to calculate VOM costs resulting from the *direction*.

7.4 Transport

The Claimant is charged a variable transport charge per unit of GJ delivered. The cost per unit is provided in a confidential invoice. This $/GJ was applied to the gas usage during the *direction*.

Based on the evidence provided, Synergies accepts this cost was reasonably calculated and incurred due to the *direction*.

7.5 Claim 3 results

Table 32 Claim 3 final compensation allowed

Item	Costs claimed	Synergies' draft determination
Gas costs	$238,567	$238,567
Start costs	$21,806	$21,806
Variable operating & maintenance (VOM)	$10,801	$10,801
Transport	$3,287	$3,287
Cost of Direction (COD)	**$274,460**	**$274,460**
Compensation entitlement (DCP)	$198,349	$198,349
Additional compensation amount (COD – DCP)	**$76,111**	**$76,111**

Source: Claimant 3, Synergies.

8 Conclusion

In this draft determination, Synergies concludes as follows.

- Claimant 1's costs to comply with the *direction* are slightly more than claimed, due to Synergies applying our preferred, more accurate approach to all gas cost claim calculations. On this basis, Claimant 1 is entitled to additional compensation of $1,640,208.
- Claimant 2's costs to comply with the *direction* are as claimed and is entitled to additional compensation of $30,703.
- Claimant 3's costs to comply with the *direction* are as claimed and is entitled to additional compensation of $76,110.

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