# Additional compensation claims arising from AEMO directions on 4 and 16 December 2020 - DRAFT DETERMINATION

An independent expert report for AEMO

19 April 2021

Synergies Economic Consulting Pty Ltd
www.synergies.com.au

Synergies
ECONOMIC CONSULTING

## Disclaimer

Synergies Economic Consulting (Synergies) has prepared this report exclusively for the use of the party or parties specified in the report (the client) for the purposes specified in the report (Purpose). The report must not be used by any person other than the client or a person authorised by the client or for any purpose other than the Purpose for which it was prepared.

The report is supplied in good faith and reflects the knowledge, expertise and experience of the consultants involved at the time of providing the report.

The matters dealt with in this report are limited to those requested by the client and those matters considered by Synergies to be relevant for the Purpose.

The information, data, opinions, evaluations, assessments and analysis referred to in, or relied upon in the preparation of, this report have been obtained from and are based on sources believed by us to be reliable and up to date, but no responsibility will be accepted for any error of fact or opinion.

To the extent permitted by law, the opinions, recommendations, assessments and conclusions contained in this report are expressed without any warranties of any kind, express or implied.

Synergies does not accept liability for any loss or damage including without limitation, compensatory, direct, indirect or consequential damages and claims of third parties, that may be caused directly or indirectly through the use of, reliance upon or interpretation of, the contents of the report.

Synergies
ECONOMIC CONSULTING

Brisbane
Level 8, 10 Felix Street
Brisbane QLD 4000
P 61 7 3227 9500
F 61 7 3221 0404

Perth
L12, 172 St Georges Terrace
Perth WA 6000
P 61 407 348 612
F 61 7 3221 0404

Sydney
Suite 518, 377 Kent Street
Sydney NSW 2000
P 61 2 8915 6235
F 61 7 3221 0404

Melbourne
Level 9, 440 Collins Street
Melbourne VIC 3000
P 61 3 8692 7272
F 61 7 3221 0404

Darwin
Level 1, 48-50 Smith St Mall
Darwin NT 0800
P 61 419 412 369
F 61 7 3221 0404

W www.synergies.com.au

# Contents



# Tables

# 1 Introduction

Synergies Economic Consulting (Synergies) has been appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine additional compensation claims for a *referred directed participant*, (the Claimant) 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 19 April 2021 and a final determination by 18 June 2021. This will allow AEMO to complete the intervention settlement process by the required deadline of 1 July 2021.

In accordance with the Intervention Settlement Timetables for the 4 and 16 December 2020 Directions, Synergies is issuing this draft report on 19 April 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 resulting from these directions under the NER, as follows:

- Section 2 sets out the National Electricity Rules requirements relevant to making a determination for additional compensation;
- 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 in relation to the directions; and
- Section 6 provides our conclusion.

# 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 company that has submitted a claim for additional compensation was a *directed participant* on 4 and 16 December 2020 for the purposes of clause 3.15.7B.

Between 4 and 16 December 2020, AEMO issued *directions* to South Australian Market Participants to maintain power system security – summarised in Table 1. In response, the *Claimant* modified the operations of three of its generating units to respond to AEMO's *directions* and in turn incur costs.

**Table 1 Summary of the relevant South Australia directions on 4 and 16 December**

| Direction | directed participant | Issue time | Cancellation time | Directed Unit |
|---|---|---|---|---|
| 80688 | Direction | 11:31 hrs, 04/12/2020 | 11:05 hrs, 04/12/2020 | Unit A, Unit B |
| 80928 | Cancellation | 03:54 hrs, 08/12/2020 | 04:00 hrs, 08/12/2020 | Unit A, Unit B |
| 81270 | Direction | 17:49 hrs, 16/12/2020 | 18:05 hrs, 16/12/2020 | Unit C |
| 81506 | Cancellation | 17:23 hrs, 20/12/2020 | 17:30 hrs, 20/12/2020 | Unit C |

**Source:** AEMO.

As such, as a *directed participant*, the Claimant was entitled to compensation under clause 3.15.7, 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.

### 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, or will be, and/or will be principally managed by:

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

- 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.

## 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

[2] For instance, in South Australia, ElectraNet plans to commission the first two of four planned synchronous condensers the Davenport substation in mid-2020 and a second two at the Robertstown substation by the end of 2020. They will be commissioned by early 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).

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
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 participant has made a claim for compensation for additional net direct costs pursuant to clause 3.15.7B (a)(1).

# 3 The directions

## 3.1 4 December 2020 direction

The Claimant submitted initial and modified additional compensation claim estimates to AEMO in relation to the 4 December 2020 direction. The modified additional compensation claim incorporated a revised gas cost methodology, which was accepted by AEMO.

### 3.1.1 Details of the *directions*

AEMO issued the following directions to the Claimant on 4 December 2020.

**Table 2 AEMO's direction on 04 December 2020**

| Directed unit | Event Number | Issued date/time | Effective datetime | End datetime | Reason |
|---|---|---|---|---|---|
| Unit A | 1-1 | 11:00 hrs, 04/12/2020 | 22:30 hrs, 04/12/2020 | 04:00 hrs, 08/12/2020 | System strength |
| Unit B | 1-1 | 11:00 hrs, 04/12/2020 | 01:30 hrs, 05/12/2020 | 13:30 hrs, 07/12/2020 | System strength |

**Source:** AEMO

### 3.1.2 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the 4 December 2020 direction as summarised in Table 3

**Table 3 AEMO's settlement compensation amounts in respect of 4 December 2020 directions**

| Directed unit | Event number | Billing week | Final billing statement | DCP | Retained trading amounts | Settlement compensation |
|---|---|---|---|---|---|---|
| Unit A | 1-1 | 49 | 04/01/2020 | $68,089 | -$7,363 | $75,452 |
| Unit A | 1-1 | 50 | 11/01/2020 | $142,214 | -$73,388 | $215,602 |
| Unit B | 1-1 | 49 | 04/01/2020 | $58,876 | -$10,417 | $69,294 |
| Unit B | 1-1 | 50 | 11/01/2020 | $100,311 | -$62,300 | $162,611 |

**Source:** AEMO

DCP is calculated in accordance with NER Clause 3.15.7(c). The Retained Trading Amount (RTA) is calculated in accordance with NER 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 the amount of compensation the directed participant is entitled to receive (DCP) minus RTA and included in the Final Billing statement.

## 3.2 16 December 2020 direction

The Claimant also submitted initial and modified additional compensation claim estimates to AEMO in relation to the 16 December 2020 direction.

### 3.2.1 Details of the *directions*

AEMO issued several directions on 16 December 2020 requiring the provision of system strength services in the National Electricity Market (NEM). Compensation was payable to multiple *Market Participants*. AEMO issued the following direction to the Claimant on 16 December 2020:

**Table 4 AEMO's direction on 16 December 2020**

| Directed unit | Event Number | Issued date/time | Effective datetime | End datetime | Reason |
|---|---|---|---|---|---|
| Unit C | 1-1 | 18:00 hrs, 16/12/2020 | 1:30 hrs, 17/12/2020 | 17:30 hrs, 20/12/2020 | System strength |

**Source:** AEMO

### 3.2.2 Initial compensation

In accordance with the above NER provisions, AEMO calculated settlement compensation for the 16 December 2020 direction as follows:

**Table 5 AEMO's settlement compensation amount in respect of 16 December 2020 directions**

| Directed unit | Event number | Billing week | Final billing statement | DCP | Retained TA | Settlement compensation |
|---|---|---|---|---|---|---|
| Unit C | 1-1 | 51 | 18/01/2021 | $188,091 | $32,033 | $156,058 |
| Unit C | 1-1 | 52 | 22/01/2021 | $46,710 | $14,304 | $32,406 |

**Source:** AEMO

# 4 The claims for additional compensation

## 4.1 Additional compensation in respect of 4 December 2020

The Claimant has submitted the following claims for additional compensation for the 4 December 2020 direction as a *directed participant*.

**Table 6 Claimant's additional compensation claim estimate in respect of direction of 4 December 2020**

| Item | Unit A Cost | Unit B Cost |
|---|---|---|
| Gas at a blended cost for the period | $235,003 | $186,461 |
| Start cost | $12,017 | N/A |
| Variable and operating maintenance (VOM) | $9,401 | $7,279 |
| Contingency raise recovery cost | $747 | $706 |
| Cost of Direction (COD) | $257,168 | $194,446 |
| Amount of compensation (DCP) | $210,303 | $159,187 |
| **Additional compensation (COD – DCP)** | **$46,865** | **$35,259** |

**Source:** The Claimant.

## 4.2 Additional compensation in respect of 16 December 2020

The Claimant has submitted the following claims for additional compensation for the 16 December 2020 direction as a *directed participant*.

**Table 7 Claimant's additional compensation claim estimate in respect of direction of 16 December 2020**

| Item | Unit C Costs |
|---|---|
| Gas at a blended cost for the period | $283,449 |
| Start cost | N/A |
| VOM | $0 |
| Contingency raise recovery cost | $1,167 |
| Cost of Direction (COD) | $284,616 |
| Amount of compensation (DCP) | $234,801 |
| **Additional compensation (COD – DCP)** | **$49,815** |

**Source:** The Claimant.

## 4.3 Total additional compensation claimed

**Table 8 Summary of total additional compensation claimed**

| Unit | Direction date | Total additional compensation claimed |
|---|---|---|
| Unit A | 4 December 2020 | $46,865 |
| Unit B | 4 December 2020 | $35,259 |
| Unit C | 16 December 2020 | $49,815 |
| **TOTAL** | | **$131,939** |

# 5 Synergies' assessment of the claims

This section analyses the reasonableness of the Claimant's additional compensation claim and sets out Synergies' draft position on each component of the claim.

## 5.1 Gas costs

The claimant's method to calculating the additional gas costs is as follows:

- The claimant derived a weighted average gas price by combining 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 contracts.
- Finally, the generating unit's total allocated quantity of gas was multiplied by the average gas price across both contracts.

Synergies replicated this analysis but used 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 gives a slightly different result in the case of generating Unit A and Unit C and 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 9.

**Table 9 Summary of total gas costs claimed versus Synergies estimate.**

| Unit | Direction date | Total gas cost (as claimed) | Total gas cost (Synergies calculation) | Difference |
|---|---|---|---|---|
| A | 4 December 2020 | $235,003 | 233,160 | -$1,842 |
| B | 4 December 2020 | $283,449 | 280,336 | -$3,113 |
| C | 16 December 2020 | $186,461 | 186,461 | $0 |

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

The claimant's supporting evidence provides copies of invoices from a gas supplier for each of the two contracts.

Following further communications with the Claimant by email and telephone, Synergies established that the gas quantities were actual quantities measured at the power station's gas blending station, which mixed gas supplied from the two sources before the blended gas is delivered to the generating units. On this basis, we accept that the Claimant's calculation method accurately reflects the actual quantities of gas burned in the relevant generating units.

The claimant further advised that the gas supply agreements impose different terms of service, in addition to having different gas prices. The more expensive of the two contracts is subject to a minimum daily quantity. For this reason, despite taking most of their gas from under the cheaper supply contract, the generating units were always drawing some amount of gas from the more expensive of the two contracts. Synergies accepts this as a commercially reasonable arrangement and accepts the evidence provided as to the price of gas supplied.

Noting that one of the gas contracts is subject to minimum daily quantities, Synergies advised the Claimant that it would need more information before it could allow the costs arising under this contract to be included among the compensable costs. In particular, it is necessary to establish what alternative uses the contracted gas could have been put to, had the Claimant not been directed in the manner it was. For instance, could the Claimant have traded some or all of the gas and, if so, how much and at what price? The Claimant advised that it needed further time to provide this information than is permitted by the timeframe for publishing this Draft Determination. However, the Claimant has also advised that it had alternative uses for the gas, so there is likely to have been an opportunity cost to burning it to comply with the directions.

Synergies has decided not to allow the costs of any gas supplied under the take or pay contract on the grounds that it requires more information in order to quantify the actual avoidable cost for the Claimant as opposed to a sunk cost that is not compensable. We anticipate that we may have additional information from the Claimant on this question for the purposes of our Final Determination in which case we may allow part or all of the claimed gas value under that contract.

## 5.2 Start costs

The claimant's method to calculating the start costs was as follows:

- The claimant identified the type of start as being a cold start following a period offline 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.
- 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).

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

Synergies' preliminary view is to accept the start cost estimates, recognising that we may revisit the gas price used in this calculation, once we have reached a final view on the appropriate treatment of gas consumed under the take or pay contract (see previous section)

## 5.3 Variable operating and maintenance (VOM) costs

The claimant's method to calculate the VOM costs is as follows:

- A per interval VOM cost was calculated based on an 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 Claimant revised its claim in respect of Unit A and Unit B and in this updated claim for those two units the VOM cost item is set out, although it had been absent from the initial claim. The claim for Unit C was not updated further following the re-submitted claim for Unit A and Unit B. Thus, for Unit C, the claim makes no mention of VOM costs. This appears to have been an oversight.

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 offline 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. AEMO advises that it is reasonable to conclude that Unit A, Unit B and Unit C would not have been operating during the period in which they were subject to the directions, but for those directions.

On the basis of the above, we agree with the inclusion of VOM costs for Unit A and Unit B and consider that VOM costs should also be included for Unit C. We calculated the VOM costs for Unit C by assuming the same per interval cost demonstrated by the Claimant in its claim for Unit A and Unit B and multiplying this by the number of intervals that Unit C was operating under AEMO's direction.

## 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. Synergies has not verified these data by collecting FCAS raise unit costs from the market independently, since the values are small.

In conclusion, subject to the figures reflecting a correct interpretation of the FCAS cost allocation rules (which we have not assessed), this methodology appears reasonable, and the cost is relatively minor. Therefore, Synergies has resolved to allow this element of the compensation claim.

## 5.5 Results

Our assessment of the Claimant's total claimed costs from an accounting perspective is summarised in Table 10, which permits a ready comparison against the claimed amounts. Our modifications to the calculation approach for gas (in the case of Unit A and Unit C) and VOM (adding this cost for Unit C) produces a small reduction in the

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

value of the relevant costs in the case of Unit A, a small increase in the case of Unit C and no change in the relevant costs for Unit B. We note that overall, these reductions are minor and amount to less than one percent of the Claimant's estimated total costs.

**Table 10 Summary of claimed costs as recalculated by Synergies (accounting perspective)**

| Component | Unit A | Unit B | Unit C |
|---|---|---|---|
| Directions period | 4/12/2020 | 4/12/2020 | 16/12/2020 |
| Total costs presented by Claimant | $257,168 | $194,446 | $284,616 |
| Accounting costs calculated by Synergies | | | |
| Gas costs **(a)** | | | |
| Contract 1 (variable) | $171,549 | $141,659 | $166,473 |
| Contract 2 (take or pay) | $61,611 | $44,802 | $113,862 |
| Total | $233,160 | $186,461 | $280,336 |
| FCAS costs | $747 | $706 | $1,167 |
| Start costs | $12,017 | $0 | $0 |
| VOM costs | $9,401 | $7,279 | $10,675 |
| Total accounting costs recognised by Synergies | $255,325 | $194,446 | $292,178 |
| Change relative to claim | -$1,842 | $0 | $7,562 |
| DCP (all billing periods) | $210,303 | $159,187 | $234,801 |
| Potential additional compensation if all costs are demonstrated to be compensable | $45,022 | $35,258 | $57,377 |

(a) Gas costs are as recalculated by Synergies (see Section 5.1).
**Source:** Synergies analysis

As we have already set out in the previous section, the Claimant's costs in operating the generating units are not necessarily compensable. Indeed, for the purposes of this Draft Determination, we have assumed that the gas consumed under the take or pay contract was a sunk cost that could not otherwise be offset by the Claimant. We expect to revisit this assumption for our Final Determination. Depending on the additional information the Claimant can provide, we may allow some or all of the gas costs under Contract 2.

Our assessment of compensable costs (being economic costs incurred as a result of the direction) is summarised in Table 11. It shows that the omission of the gas costs under the take or pay contract reduces the compensable costs to below DCP. That is, no additional compensation is payable.

**Table 11 Summary of compensable costs determined by Synergies**

| Component | Unit A | Unit B | Unit C |
|---|---|---|---|
| Directions period | 4/12/2020 | 4/12/2020 | 16/12/2020 |
| Total compensable costs | | | |
| Gas costs **(a)** | | | |
| Contract 1 (variable) | $171,549 | $141,659 | $166,473 |
| Contract 2 (take or pay) | $0 | $0 | $0 |
| Total | $171,549 | $141,659 | $166,473 |
| FCAS costs | $747 | $706 | $1,167 |
| Start costs | $12,017 | $0 | $0 |
| VOM costs | $9,401 | $7,279 | $10,675 |
| Total | $193,714 | $149,643 | $178,316 |
| DCP (all billing periods) | $210,303 | $159,187 | $234,801 |
| Shortfall (Total compensable costs minus DCP) | -$16,589 | -$9,544 | -$56,485 |
| Add Compensation (adjusted) | $0 | $0 | $0 |

(a) Gas costs are as recalculated by Synergies (see Section 5.1).

**Source:** Synergies analysis

# 6 Conclusion

Synergies has formed the preliminary view that no additional compensation is payable. As noted, Synergies anticipates that the Claimant may be able to provide additional information that could alter our treatment of some of these costs, which, due to timing constraints, has not been able to be considered in this Draft Determination. If we are persuaded by this additional information that some of the costs that we have excluded from the compensation calculation were indeed avoidable, then we will revise our assessment.

The *directed participant* has been informed of these preliminary determinations, the reasons for them, and the amount of compensation.