Draft report on claims for additional compensation arising from directions on 25 April 2017

An independent expert report prepared for AEMO

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Executive Summary

Synergies Economic Consulting (Synergies) was appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine additional compensation in respect of two *directions* AEMO issued on 25 April 2017. This draft report is published pursuant to clause 3.12.3 (c) (1) (i) of the National Electricity Rules (NER).

For South Australia to maintain in a secure operating state, there is a power system security requirement for a minimum number of synchronous generating units connected to the 275 kV network to be on-line at all times in South Australia. AEMO determined that this power system security requirement would not be met from 0300 hrs on 25 April 2017.

AEMO issued 2 *directions* to participants in the South Australia region. The first *direction* (*Direction 1*) was issued at 02:34 on 25/04/17 and cancelled at 14:15 on 25/04/17. The second *direction* (*Direction 2*) was issued at 07:45 on 25/04/17 and cancelled at 12:07 on 26/04/17.

AEMO determined in both cases that the *directions* were *directions* for the provision of energy and duly calculated compensation for the energy services provided under the *direction* in accordance with clause 3.15.7(c) of the NER. On 24 May 2017, AEMO notified both directed participants in accordance with clause 3.15.7(e). AEMO determined that:

- The party subject to *Direction 1* (*Directed Participant 1*) was entitled to compensation of $25,817
- The party subject to *Direction 2* (*Directed Participant 2*) was entitled to compensation of $202,526

Subsequently, both directed participants have responded with claims for additional compensation based on their estimates of net direct costs.

- *Directed Participant 1* has claimed for an additional $89,966.
- *Directed Participant 2* has claimed for an additional $28,694.

Synergies draft determination of the total compensation payable pursuant to 3.15.7B for each claim is as follows.

- *Directed Participant 1* should be awarded its claim for additional compensation in full, with an amount of $89,966 being payable.
- *Directed Participant 2* should be awarded part of its claim for additional compensation in full, with an amount of $12,042 being payable.

The Directed Participants have been individually informed of these determinations, the reasons for them, and the amounts of compensation payable.

Contents

1 Introduction

Synergies Economic Consulting (Synergies) was appointed by the Australian Energy Market Operator (AEMO) as an independent expert to determine two claims for additional compensation made under clause 3.15.7B of the NER in respect of *directions* that AEMO issued on 25 April 2017.

AEMO is required by the NER to use reasonable endeavours to complete all obligations, including final settlement, no later than 150 days after the end of this *Direction*. The 150 business days ends on 22 November 2017.[1]

In accordance with the Intervention Settlement Timetable for the 25 April *Directions*, Synergies is issuing this draft report on 23 August 2017. The Directed Participants have been notified of our draft determination.

1.1 Structure of this report

In the remainder of this report, we set out the basis for our draft determination of compensation resulting from the *directions* under the NER.

- Section 2 describes the circumstances, details and effects of the *directions* and summarises AEMO's original compensation determinations.
- Section 3 sets out the elements of each claim and the evidence provided to substantiate each element.
- Section 4 provides Synergies assessment of each claim, setting out our reasoning for accepting, rejecting or modifying each element of each claim.
- Section 5 summarises our findings as to compensation payable and offers some comment on a provision of the NER.

[1] AEMO, 2017, Intervention Settlement Timetable for Directions on 25&26 April 2017, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Settlements_and_Payments/Prudentials/Settlement-Timetables/Intervention-Settlement-Timetable---SA-directions-on-25-and-26-Apr-2017.pdf.

2 Background

2.1 The Directions

For South Australia to maintain in a secure operating state, there is a power system security requirement for a minimum number of synchronous generating units connected to the 275 kV network to be on-line at all times in South Australia. According to AEMO, pre-dispatch indicated that this power system security requirement was not being met from 0300 hrs on 25 April 2017 (MN 58429).

Following this, AEMO issued 2 *directions* to participants in the South Australia region (MN 58451). The first *direction* (*Direction 1*) was issued at 02:34 on 25/04/17 and cancelled at 14:15 on 25/04/17 (see MN 58432). The subject of this *direction* (*Directed Participant 1*) in this case operated its generating unit out of merit in accordance with this *direction* to meet the power system security requirement. AEMO determined that the affected period for this *direction* is from dispatch intervals ending 02:35 to 14:15 on 25 April 2017.

The second *direction* (*Direction 2*) was issued at 0:745 on 25/04/17 and cancelled at 12:07 on 26/04/17 (see MN 58439). Pursuant to this *Direction*, a generating unit owned by *Directed Participant 2* was brought online. AEMO determined that the affected period for this *direction* is from dispatch intervals ending 07:45 on 25 April to 12:10 on 26 April 2017.

AEMO issued two successive *directions*, Synergies understands, because the generating units that were the subject of *Direction 1* could be brought online more quickly than the unit the subject of *Direction 2*. However, since the generating unit directed by *Direction 2* provided a lower cost means of satisfying the relevant power system security requirement, *Direction 2* was issued such that the units brought on under *Direction 1* were replaced by the more efficient unit that was the subject of *Direction 2*. This reduced the overall cost of the *direction* events.

2.2 Compensation determined by AEMO

AEMO classified each of the two *directions* as a *direction* for the provision of an energy service and that compensation was thereby payable under clause 3.15.7. AEMO calculated the compensation payable to the Directed Participant, following the formula set out in clause 3.15.7(c) and notified the Directed Participant by email on 24 May 2017.

AEMO calculated the amount of compensation the Directed Participants are entitled to receive based on the 90th percentile spot price level for the 12 months prior and the quantity of energy dispatched during the directed dispatch intervals.

Both *directions* were issued in the same trading day and therefore both compensation amounts relied on the same valuation of "AMP", defined in clause 3.15.7(c) as:

> the price below which are 90% of the spot prices or ancillary service prices (as the case may be) for the relevant service provided … for the 12 months immediately preceding the trading day in which the *direction* was issued;

On this basis, AEMO determined that the value of energy to be applied for the purposes of determining compensation was $160.49/MWh.

The combined amount of energy supplied under both *directions* was 1,423MWh. Total compensation determined by AEMO in accordance with 3.15.7(c) was $25,817 and $202,526 for *Directed Participants 1* and *2* respectively. These results are summarised in Table 1.

Table 1 Directed Participant compensation determinations under 3.15.7(c)

	AMP	Total compensation (DCP)
Directed Participant 1	$160.49	$25,817
Directed Participant 2	$160.49	$202,526

Source: AEMO

AEMO notified each of the *Directed Participants* in accordance with 3.15.7(e) of its compensation determination by separate emails dated 24 May 2017.

3 The Claims

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

(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 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.

Both of the *Directed Participants* have subsequently lodged claims for additional compensation under clause 3.15.7B. The claim lodged by *Directed Participant 1* is referred to hereafter as "*Claim 1*" and that lodged by *Directed Participant 2* as "*Claim 2*".

3.1 *Claim 1*

Directed Participant 1 responded to AEMO's notification of compensation payable pursuant to clause 3.15.7 on 10 August 2017. It claimed an additional $89,966 in compensation, based on its calculation of its net direct costs, minus deductions. Synergies regards this as a claim under 3.15.7B(a), with net direct costs to be determined in accordance with 3.15.7B(a3).

3.1.1 Net direct costs

The net direct costs, as set out in *Claim 1*, to have been incurred to comply with *Direction 1* amount to $115,783. This estimate of total net direct cost comprises the items listed below.

- A start charge of $2,000 per unit for each of the 8 units directed, representing maintenance costs associated with the relevant generating unit "brought forward by the *Direction*". Synergies understands that these start costs are separate to any fuel costs associated with start.
- A total gas cost of $99,366 arising from a stated fuel burn of 9,383GJ. The costs comprised a commodity and transport cost with prices substantiated with supplier receipts.

- An additional gas imbalance charge of $325.50, again substantiated with a supplier receipt.
- An FCAS charge of $91.28, consistent with AEMO's final settlement statement.

3.1.2 Net claim

From the total net direct costs, *Claim 1* deducted an amount as required under sub clause 3.15.7B(a)(2) corresponding to the total compensation notified by AEMO, namely the amount of compensation a Directed Participant is entitled to receive under 3.15.7(c), being $25,816.92.

Combining the total net direct cost with this deduction produces the net claim of $89,966. The claim is summarised in

Table 2, located in Section 4.

3.2 *Claim 2*

Directed Participant 2 replied to AEMO's notification of compensation payable pursuant to clause 3.15.7 on 2 June 2017. *Directed Participant 2* claimed additional compensation of $227,700 pursuant to clauses 3.15.7B(a1) and 3.15.7B(a3). Subsequent communications with the *Directed Participant* about the manner in which the claim was set out in its 2 June letter led to the claim being resubmitted.

Directed Participant 2 wrote to Synergies on 8 August 2017 and restated its claim as a claim for additional compensation of $28,694 pursuant to clause 3.15.7B(a) of the NER. It set out further details of its claim in an attachment to this letter.

Claim 2 sets out the *Direct Participant's* net direct costs, finding that this amount is larger than the total compensation calculated by AEMO under 3.15.7(c). The claim is simply for the difference between these two amounts.

3.2.1 Net direct costs

The net direct costs claimed by *Directed Participant 2* as a result of complying with the *direction*, as set out in the claim, amount to $231,220. This estimate of total net direct cost comprises the items listed below.

- A start charge of $16,000 comprising gas, electricity and parts and maintenance costs, substantiated by a spreadsheet of start costs associated with different start types, broken down by the component costs.
- An overtime cost for associated with additional staffing requirements to effect the start of $800, which has not been substantiated with supporting evidence.
- Fuel costs associated with the entire affected period of $210,900. The unit fuel costs have been substantiated by providing three consecutive internal emails to *Directed Participant 2*'s generation traders indicating the daily gas values on which they should base their generation offers. The emails cover the days 24 April to 26 April inclusive.
- An estimate of the variable operating and maintenance (VOM) costs for the generator arising from the *direction* of $3,520, based on its estimate of directed energy production at $2.75/MWh. This unit cost was cited from a public report prepared by ACIL Allen for the Interregional Planning Committee and published in 2009.[2] The published unit cost figure was adjusted for inflation at 2.5 per cent per annum by *Directed Participant 2*.

[2] ACIL Tasman, April 2009, Fuel resource, new entry and generation costs in the NEM, available online, https://www.aemo.com.au/media/Files/Other/planning/419-0035%20pdf.pdf, accessed 17/08/2017, page 28.

3.2.2 Net claim

From the total net direct costs, the claim deducted an amount as required under sub clause 3.15.7B(a)(2) corresponding to the total compensation notified by AEMO, namely the amount of compensation a Directed Participant is entitled to receive under 3.15.7(c), being $202,525.88.

Combining the total net direct cost with this deduction produces the net claim of $28,694. The claim is summarised in Table 3, located in Section 4.

4 Synergies Assessment of the Claims

4.1 Effect of clause 3.15.7B(a4)

Both *Claim 1* and *Claim 2* have been set out such that fuel costs are estimated for the entire affected period, but not reported by trading interval. In practice, gas costs are directly attributable to individual trading intervals. We expect that the costs have been left aggregated because of the anticipated effect of applying the materiality threshold provided under clause 3.15.7B(a4).

In this draft report, we reiterate our finding from an earlier report that for a claim under 3.15.7B(a) that is otherwise valid, a single materiality threshold of $5,000 should be applied, irrespective of the number of trading intervals that the *direction* pertained to. Our reasoning is set out in detail in that earlier report[3]. This renders irrelevant whether the costs associated with a claim are reported by trading interval or not, since it will be only the aggregate of costs to be assessed against the threshold provided under clause 3.15.7B(a4).

4.2 Treatment of maintenance and operating costs

The most difficult issue we encountered in determining the two claims referred to us concerns the proper treatment of maintenance costs and other costs that may be affected by the pattern and level of use of generating plant. The claims invited us to consider a number of different issues that we broadly discuss at the outset in order to ensure proper understanding of the reasons for what might appear superficially to be different treatments of the two claims.

Compensation for maintenance costs are directly provided for under clause 3.15.7B(a3) in two ways, as the clause allows for net direct costs to include incremental maintenance costs[4] and the acceleration costs of maintenance work[5]. Operating costs in the form of labour costs are explicitly provided for[6], while other forms of operating costs (variable costs other than labour, maintenance and fuel) could be permitted provided they were incurred in order to comply with the direction.[7] Focussing on maintenance and labour it is worth considering what may drive the types of costs that could see these items appear in a legitimate claim for compensation.

[3] Synergies, August 2017, *Final Report on additional compensation claims arising from AEMO directions on 1 December 2016*, pages 13 – 17.

[4] 3.15.7B(a3)(2)

[5] 3.15.7B(a3)(4)

[6] 3.15.7B(a3)(3)

[7] 3.15.7B(a3)(6)

4.2.1 Maintenance costs driven by starts

Plant maintenance schedules often provide for different levels of servicing to be undertaken every X number of starts. Thus, while the physical deterioration in a plant associated with an individual start is not directly observable, it is nonetheless reasonable to attribute to the start some maintenance-related cost. The cost caused will be the cost associated with shifting a set of future maintenance costs (scheduled or otherwise) slightly forward in time.

In practice, there is considerable uncertainty in quantifying the maintenance costs associated with an individual start – a point recognised by Harding Katz in their recent draft report on compensation for *directions* on 28 and 29 March 2017[8]. In that report, the independent expert considered the strengths and weaknesses of multiple approaches to estimating start-up costs arising from a *direction* to run. Among other problems, Harding Katz noted that maintenance activities scheduled long into the future, while reasonable to forecast, may not eventuate.

Ignoring start costs would be inconsistent with the intention of the compensation arrangements – starts unquestionably bring forward costs. An LRMC-based method would be more faithful to the true nature of these costs – being the time value of incurring a financial cost sooner. But such methods are also sensitive to the underlying assumptions and this, in turn, would invite gaming, be expensive to implement and produce potentially quite variable and contested compensation outcomes.

Harding Katz concluded that the appropriate method to use in calculating the incremental maintenance costs associated with a start was what it called the "single cycle method", described as:[9]

> …the estimated total maintenance and refurbishment costs for the life of the original operating equipment from its commissioning date divided by the estimated total number of starts over the life of the equipment.

In our view, Harding Katz have adopted a sensible approach to the estimation of the incremental maintenance costs associated with starts. In the absence of compelling contrary evidence, the simplicity of the single-cycle method is appropriate to calculating the maintenance cost of a start in light of the uncertainty as to what maintenance costs will in fact be incurred in the future. We consider it reasonable to favour a method that is transparent, robust and relatively inexpensive to apply in preference to a more theoretically sound method applied at greater expense and uncertainty for no demonstrable gain in precision.

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[8] Harding Katz, July 2017, Compensation for Directions in Queensland on 28 and 29 March 2017, Independent Expert Draft Report.

[9] Harding Katz, July 2017, Compensation for Directions in Queensland on 28 and 29 March 2017, Independent Expert Draft Report, page 6.

4.2.2 Maintenance costs driven by hours of operation

Maintenance costs can also be affected the hours of operation of a plant and not simply by the number of starts. In some cases, a specific type of plant overhaul will be triggered by either the number of starts or by the number of hours of operation, whichever is reached first. It is also possible that in some cases, a particular overhaul type may only be required upon reaching a specified number of hours of operation. That is, it may be a cost that is independent and additional to the cost caused by the number of starts.

In either case, we think it would be require detailed and well documented analysis to demonstrate separate maintenance costs associated with starts on one hand and operation on the other. It would be necessary to see all scheduled maintenance works suitably disaggregated into those driven by different causes. Only in this way, would it be possible to assure that that no double counting was occurring.

In practice, we anticipate that the time and cost associated with accounting for maintenance costs in this way may exceed its commercial benefit to generators. Given the relative importance of maintenance costs compared to fuel costs in assessing the decision to continue operating, we would not anticipate that the maintenance costs attributable to operation play a significant role in bidding and dispatch. This could be contrasted with the role that start costs can be expected to play in judgements about whether to bid-in peaking facilities.

In summary, we concede that maintenance costs are likely to sometimes be driven by the amount of time a generator operates. However, we think that care must be taken to avoid double counting these costs and we anticipate that the effort required to disaggregate them from other maintenance costs may not be justified by the sums involved.

4.2.3 Labour costs

To be relevant to a compensation claim under 3.15.7B, labour costs must be caused by the direction. This forces us to consider the conditions under which staffing requirements should be treated as fixed or variable. For the most part, staffing requirements seem likely to vary little with the level of operation of a plant – that is, they would be treated as fixed.

Facilities may require specialist expertise or additional labour when starting up and shutting down, but if such events are routine – such as in the case of a peaking plant, then the addition of these increments of labour costs might still be considered fixed costs. That is, these might be considered unavoidable costs arising from being a generator operating according to a particular duty.

We have already considered the costs associated with maintenance, which are a separate issue that does not require further attention here.

Unexpected or irregular events may produce higher labour costs than normal and we consider that these are likely to be appropriate to treat as variable costs. We note though that this appears to be a very narrow class of costs.

In summary, we think that labour costs are potentially allowable, but the types of labour costs that could be considered avoidable is likely to be narrow and any labour costs that are the subject of a claim for compensation must be clearly identified as incremental.

4.2.4 Variable operating and maintenance costs

In modelling the electricity market, it is common to take account of a cost term referred to as "variable operating and maintenance costs" (VOM). VOM estimates are undeniably useful for these purposes, since they can be easily integrated with the estimation of SRMC necessary to simulate bidding behaviour.

One adverse consequence of the convenience of reducing all non-fuel variable costs to a single term expressed in dollars per MWh is insensitivity to changes in the operating profile of a plant. While an estimate of VOM expressed this way could perfectly capture the average maintenance and labour costs per MWh for a given type of plant operating a decade ago, it may be quite inaccurate now, when the operating profile of the plant has changed considerably.

We believe that the maintenance and labour costs discussed above constitute the major part of those costs that VOM seeks to capture. That is, VOM is largely an alternative way of expressing these costs. In the context of a claim for compensation, we believe that it is appropriate to expect that well supported estimates of the constituent costs will be provided. While it is possible to do this with terms expressed in dollars per MWh, we consider that additional caution may be required.

4.3 *Claim 1*

4.3.1 Net Direct Costs

Start costs

Start costs are not explicitly provided for in clause 3.15.7B(a3) but could reasonably be understood to include fuel costs and maintenance costs. Fuel costs are not relevant in this case, since the start charge in *Claim 1* does not include fuel costs.

Directed Participant 1 supported its estimate of start costs for each of the 8 units operated pursuant to the *direction*, by providing a spreadsheet setting out the scheduled maintenance requirements of the generators in question, as determined by the number of starts. The same spreadsheet included a 2007 estimate of the cost associated with each level of maintenance overhaul (these costs were adjusted to 2015 dollars for the claim). Thus, for instance every 500 starts, a particular plant overhaul might be required at a certain estimated cost, while another type of overhaul might be required at 1000 starts at a different estimated cost.

In the spreadsheet provided, each of these levels of maintenance was converted into an average cost per maintenance type per start and then the cost of all maintenance types per start was summed to give a total average maintenance cost per start. While the 2007 estimate of costs was adjusted for inflation, the spreadsheet did not attempt to reflect the time value of money in valuing the future maintenance costs that are brought forward as a result of responding to *Direction 1*.

Since at least some of the generating units the subject of *Direction 1* are very old, we think that it is quite plausible the plant would be retired before some of the included maintenance overhauls fall due. Equally, maintenance might be deferred as the expected value from investing in the future reliability of these plant might be heavily discounted by the Directed Participant.

The spreadsheet provided by *Directed Participant 1* essentially applies the single cycle method endorsed by Harding Katz. For the reasons described in Section 4.2.1, we also endorse this approach where there is a high level of uncertainty about the actual “what if” maintenance regime.

Accordingly, we conclude that Claim 1 has appropriately estimated the start costs, based on the single cycle method of attributing maintenance costs and that its claim for $16,000 in start costs should be allowed.

Cost of gas

Clause 3.15.7B(a3) explicitly allows for fuel costs to be recovered as part of net direct costs incurred as a result of a *direction*. As noted, *Directed Participant 1*’s unit gas costs have been substantiated with invoices. The total volume of gas claimed to have been burned as a result of the *direction* appeared high on initial inspection. Further investigation and information provided by both AEMO and *Directed Participant 1* shows that the fuel cost estimates were broadly consistent with expectations. The poor fuel efficiency of the directed units reflects the combined contribution of the considerable age and inflexibility of the plant, the fuel penalty associated with reheating cooled plant and the requirement that all 8 units operate at the very bottom of their output range.

Claim 1 included a gas imbalance charge of $325.50, again substantiated with a supplier receipt. We noted that the charge in question was raised in the invoice against 24 April 2017, rather than 25 April – the day of the *directions*. *Directed Participant 1* explained that this was due to the fact that the gas market operates according to a trading day ending at 06:00. The additional gas required between the start of the *direction* and the end the 24 April gas trading day caused the imbalance on that day and, because it occurred late in the day, there was no opportunity to change the nomination. By contrast, *Directed Participant 1* was able to nominate greater quantities of gas for the 25 April gas trading day as required to comply with the *direction* over the period 06:00 to 14:15. Thus, imbalance charges were only incurred as a result of *Direction 1* on the gas trading day of 24 April 2017 and these are the charges set out in the claim.

We conclude that the gas cost of $99,366 and a further $325.50 for gas imbalance charges should be accepted.

FCAS charge

An FCAS charge of $91.28, which *Directed Participant 1* indicated was "as per AEMO settlement statement". This charge represented the share of FCAS contingency raise charges allocated to the generator in question in accordance with AEMO's procedures for recovering ancillary service costs[10]. This item has been substantiated with information provided by AEMO.

We conclude that the FCAS charge of $91.28 should be accepted.

4.3.2 Net claim

Synergies has confirmed and allowed each of the cost items that make up the estimated net direct costs in *Claim 2*. We also confirm that deductions for prior compensation have been correctly applied in accordance with clauses 3.15.7B(a)(2) and (3). On our interpretation of 3.15.7B(a4) (see Section 4.1), the claim exceeds the $5000 threshold. On this basis, we conclude that *Directed Participant 1* should be awarded its claim for additional compensation in full, with an amount of $89,966 being payable.

4.3.3 Summary of amounts claimed and allowed

The net direct cost items claimed by *Directed Participant 1* are summarised in

[10] Contingency FCAS costs are recovered in proportion to energy consumption / generation. Contingency raise services are recovered from generators, while loads pay for contingency lower services.

Table 2 and compared against the amounts allowed by Synergies.

Table 2 Summary of *Claim 1*

Item	Claimed	Allowed	Comment
Costs			
Start costs	$16,000.00	$16,000.00	Accepted
Gas			
Commodity and transport	$99,365.97	$99,365.97	Accepted
Imbalance charge	$325.50	$325.50	Accepted
FCAS charge	$91.28	$91.28	Accepted
Total net direct costs	$115,782.75	$115,782.75	
Deductions			
Total notified compensation (referred to as "DCP" under 3.15.7(c))	$25,816.92	$25,816.92	
Net additional compensation	**$89,965.83**	**$89,965.83**	

Source: *Claim 2* and AEMO data.

4.4 *Claim 2*

4.4.1 Net Direct Costs

Start costs

As noted in relation to *Claim 1*, start costs can be claimed as net direct costs under 3.15.7B(a3) and will generally cover incremental fuel and maintenance costs arising from the *direction*. The start cost cited by *Directed Participant 2* was not initially broken down and, since incremental fuel costs had been claimed separately, we requested additional information to confirm whether the $16,000 estimate included fuel costs associated with facility start-up. *Directed Participant 2* provided additional material to substantiate the start cost estimate and conceded that the fuel costs associated with start-up had erroneously been double counted. We were then able to replace the original start-up cost estimate with a non-fuel start-up cost that comprises only maintenance and electricity costs amounting to $1,390.

A large proportion of the non-fuel start cost is attributable the electricity costs, meaning that the estimated maintenance cost component of the start cost was relatively small. Accordingly, we chose not to investigate the methods used to calculate the incremental maintenance costs associated with starts. We did not, therefore, establish whether the cost estimate reflects a single cycle method calculation consistent with the approach endorsed for *Claim 1*. In view of the magnitude of the start-related maintenance costs in *Claim 2*, we considered that the choice of maintenance cost calculation method would be relatively inconsequential, while the time penalty imposed on the Directed Participant to document its methods might be significant.

We are satisfied that a non-fuel start cost of $1,390 should be allowed.

Cost of gas

Clause 3.15.7B(a3) explicitly allows for fuel costs to be recovered as part of net direct costs incurred as a result of a *direction*. We accept *Directed Participant 2*'s unit gas costs on the strength of the internal emails provided.

Total gas burned was summarised in a spreadsheet provided by the Directed Participant, in which we uncovered the small omission of gas burned as a directed participant during trading interval ending 12:30 on 26 April 2017. *Direction 2* was cancelled during the dispatch interval ending 12:10 on that day but *Directed Participant 2* continued to dispatch for several hours.

We consider that the gas burned during the first two dispatch intervals of trading interval ending 12:30 on 26 April 2017 should be included as a net direct cost and we accordingly adjusted this estimate upwards, allowing $212,378 in total gas costs.

Overtime costs

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 not attempted to verify the cited cost of $800 as the cost of paying a technician to attend the site as a result of the *direction*. However, we regard this cost as reasonable to treat as variable, given the unexpected timing of the direction.

We consider that the $800 should be allowed, however, its separate inclusion is relevant to our response to the claim for VOM costs (see below).

VOM costs

VOM costs are clearly allowed for by clauses 3.15.7B(a3)(2), (3) and (4). *Directed Participant 2* has relied on an independent source for its estimate of these costs. The reference has separately evaluated VOM costs for all thermal plant operating in the NEM in 2009, which includes the generator in question. This suggests, *prima facie* that the VOM estimate is appropriate to include in this assessment of incremental costs. However, as we foreshadowed in our discussion of maintenance and labour costs in Section 4.2 it seems to us that the additional claim for VOM costs is problematic.

The fundamental issue raised by the inclusion of a general unit cost for VOM is the likelihood that it results in double counting maintenance costs. In the case of the generator the subject of *Direction 2*, we have already allowed a cost item to account for the average cost of maintenance associated with a start of the kind in question. There is nothing in the ACIL Tasman report that allows us to separately identify additional maintenance costs driven by the operation of the plant, as distinct from the start-up of the plant.

We don't consider that the estimates are likely to reflect an up-to-date or plant specific assessment of the maintenance and other variable operating costs of the particular generator in question. The same estimate is given for three other facilities (two in Victoria and one in South Australia) and was prepared in 2009. We note that the operating regime for all these generators is likely to have changed considerably in the intervening time and that this would have altered the averaging of maintenance and operating costs per unit of energy served (see previous discussion in Section 4.2.4).

ACIL Tasman's estimates are also problematic because they are not susceptible to interrogation. Table 16 of that report lists gives as its sources "ACIL Tasman and various sources" but provides no further guidance on how the figures were arrived at. Again, while this is reasonable in the context of providing inputs for market modelling, we don't consider this meets the standards appropriate to a compensation determination.

Accordingly, we have excluded the $3,520 claimed by Directed Participant 2 as a general VOM cost. In our final report, we remain open to allowing additional VOM costs if suitable information can be provided to demonstrate these costs while assuring that double counting has been avoided. In particular, Directed Participant 2 should consider whether more detailed information can be provided to demonstrate additional maintenance or operating costs that are not driven by starts.

4.4.2 Net claim

Synergies has determined that the following net direct costs should be allowed.

- A non-fuel start cost of $1,390, consistent with the non-fuel costs substantiated by *Directed Participant 2*, but excluding the fuel costs originally included in the claim of a $16,000 start cost.
- A total gas cost of $212,378, being slightly more than was claimed for on account of the inclusion of the estimated fuel burn in two additional dispatch intervals.
- An overtime cost of $800, equal to the amount claimed.

We have rejected the VOM cost item of $3,520 for the reasons given previously. We have recalculated the net direct cost and applied deductions for prior compensation in accordance with clauses 3.15.7B(a)(2) and (3). On our interpretation of 3.15.7B(a4) (see Section 4.1), the claim exceeds the $5000 threshold. On this basis, we conclude that *Directed Participant 2* should be awarded its claim for additional compensation in full, with an amount of $12,042 being payable.

4.4.3 Summary of amounts claimed and allowed

The net direct cost items claimed by *Directed Participant 2* are summarised in Table 3 and compared against the amounts allowed by Synergies.

Table 3 Summary of *Claim 2*

Item	Claimed	Allowed	Comment
Costs			
Cost of gas	$210,900.00	$212,378.35	Two dispatch intervals added
Start costs	$16,000.00	$1,389.51	Fuel costs removed
Overtime costs	$800.00	$800.00	Allowed in full
VOM	$3,520.00	$0.00	General cost not allowed, further substantiation required.
Total net direct costs	$231,220.00	$214,567.86	
Deductions			
Total notified compensation (referred to as “DCP” under 3.15.7(c))	$202,525.88	$202,525.88	
Net additional compensation	$28,694.00	$12,041.98	

Source: *Claim 2* and AEMO data.

5 Concluding remarks

5.1 Compensation

Based on the foregoing, we have determined that the total compensation payable pursuant to 3.15.7B for the claims are as follows:

- *Directed Participant 1* should be awarded its claim for additional compensation in full, with an amount of $89,966 being payable.
- *Directed Participant 2* should be awarded part of its claim for additional compensation in full, with an amount of $12,042 being payable.

The *Directed Participants* have been individually informed of these determinations, the reasons for them, and the amount of compensation.

5.2 Potential drafting error in NER

During our preliminary evaluation of *Claim 2*, we were required to review clause 3.15.7A in detail, due to irregularities in the way that claim was originally set out. While undertaking this review, we identified a small potential drafting flaw in that clause which we believe should be noted. Clause 3.15.7A (a2) reads as follows (emphasis added):

> 3.15.7A(a2) For the avoidance of doubt, any component of a *direction* that satisfies this clause **3.15.7(a1)** is to be considered for compensation under this clause 3.15.7A, and clause 3.15.7B, as the case may be. Any other component of the *direction* that does not satisfy clause **3.15.7(a1)** is to be considered for compensation under clause 3.15.7, and clause 3.15.7B, as the case may be.

We note that the NER does not contain a clause 3.15.7(a1) but that the provision might be sensibly interpreted if it is assumed that the intended reference was to 3.15.7**A**(a1).

In our Final Report on additional compensation claims arising the *directions* of 1 December 2016, we made the following comment:

> The issues with clause 3.15.7B(a4) outlined in Section 4.3 strongly suggest that the drafting of this clause should be clarified. We note that the compensation arrangements are now some 15 years old and might warrant review by the AEMC even were it not the case that 3.15.7B(a4) is so challenging to apply.

Any such review would also provide an opportunity to consider the potential drafting error in clause 3.15.7A(a2).