NEM EVENT – DIRECTION TO SOUTH AUSTRALIA GENERATOR – 1 MARCH 2017

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this report in accordance with clause 3.13.6A(a) of the National Electricity Rules (NER), based on information available to AEMO prior to the date of publication.

This report uses several terms that have defined meanings in the NER. They have the same meanings in this report.

All references to time in this report are based on Australian Eastern Standard Time (AEST).

Disclaimer

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1. PURPOSE

As described in clause 4.8.9 of the National Electricity Rules (NER), AEMO is permitted to intervene in the market and issue ‘directions’ and ‘clause 4.8.9 instructions’ to Registered Participants, if satisfied it is necessary:

- To maintain or re-establish the power system to a secure, satisfactory or reliable operating state.
- For reasons of public safety or otherwise for the security of the power system.

Where AEMO intervenes in the market through the issue of directions, AEMO must publish a report in accordance with NER clause 4.8.9(f) and 3.13.6A(a).

This report meets those NER obligations.

2. SUMMARY

At 1639 hours (hrs) on 1 March 2017, AEMO issued a direction to Pelican Point Power Pty Ltd (ENGIE) to synchronise and dispatch Pelican Point unit GT12 to minimum load. The direction was issued under clause 4.8.9 of the NER to maintain the power system in a reliable operating state in South Australia (SA).

AEMO made the decision to intervene in the market based on assessing the potential impact of multiple risks present at the time following an actual lack of reserve (LOR) 1 condition from 1530 hrs in SA. Pelican Point unit GT12 was the only available generating unit at the time in a position to alleviate the need for load shedding if a credible contingency event occurred.

The direction was cancelled at 1925 hrs when the supply-demand balance was alleviated and potential lack of reserve conditions did not eventuate.

3. BACKGROUND

The Pre-dispatch Projected Assessment of System Adequacy (PD PASA) runs from 0930 hrs onwards on 1 March 2017 forecast LOR1 conditions for the evening peak period in SA. The forecast LOR1 condition continued to deteriorate throughout the day and an actual LOR1 condition was declared from 1530 hrs.

In situations where AEMO identifies a potential reserve shortfall, AEMO may issue directions under NER clause 4.8.9 to maintain the power system in a reliable operating state. This led to the requirement to direct a SA Generator in order to maintain the power system in a reliable operating state.

Although no LOR2 condition was forecast by AEMO’s systems prior to the time of intervention on 1 March 2017, AEMO observed multiple coincident risks to system reliability, including high wind and demand forecast uncertainties, generator reliability issues in the prevailing high temperature conditions, and the need to reclassify contingencies as credible. AEMO made the decision to intervene after assessing these risks. It is noted that, going forward, a recent change to the NER will allow these uncertainties to be reflected in the reserve level declarations, providing additional transparency to the market.[1]

[1] *National Electricity Amendment (Declaration of lack of reserve conditions) Rule 2017 No. 17*. See also AEMO’s Reserve Level Declaration Guidelines, available at: http://www.aemo.com.au/Stakeholder-Consultation/Consultations/Consultation-on-initial-version-of-Reserve-Level-Declaration-Guidelines.

4. NER COMPLIANCE WITH THE INTERVENTION PROCESSES

4.1 Circumstances giving rise to the need for the direction

A direction was issued in SA following the assessment of potential reserve shortfall based on increasing risk factors.

On 1 March 2017, hot weather conditions occurred in SA with the peak temperature in Adelaide reaching 38.6°C. SA demand reached a peak of 2,727 megawatts (MW) at 1730 hrs. Wind generation in SA ranged between 165 MW and 415 MW between 1630 hrs and 1930 hrs.

The 0930 hrs PD PASA run (produced at 0900 hrs) on 1 March 2017 forecast an LOR1 condition in SA between 1700 hrs and 1730 hrs on 1 March 2017. AEMO issued Market Notice (MN) 57761, declaring the forecast LOR1 condition.

The forecast LOR1 condition continued to deteriorate throughout the day, and AEMO continued issuing a number of Market Notices advising the market of the forecast LOR1 conditions (MN 57762, MN 57765, and MN 57768).

The 1600 hrs PD PASA run (produced at 1530 hrs) on 1 March 2017 indicated an actual LOR1 condition in SA from 1530 hrs, expected to continue until 1830 hrs. The minimum reserve of 465 MW was expected to occur for Trading Interval (TI) ending 1730 hrs with the contingency capacity reserve requirement of 570 MW.

For dispatch interval (DI) ending 1525 hrs on 1 March 2017, Origin Energy withdrew 56 MW of generation capacity from Quarantine Power Station units 1 to 4, with volume priced at either $198.01 per megawatt hour (MWh) or the market floor price (MFP) of -$1,000/MWh. The bid reason cited was “1512P CHANGE IN AVAIL – GAS PRESSURE SL”. AEMO received information that Quarantine Power Station was experiencing issues with gas pressure on units 1, 2, 3, and 4. As a result, AEMO reclassified the simultaneous loss of multiple generating units at Quarantine as a credible contingency event from 1535 hrs (MN 57773).

AEMO assessed a number of increased risk factors present at that time, including:

- Reclassification of the simultaneous loss of Quarantine Power Station units 1, 2, 3, and 4 due to gas pressure issues.
- Significant wind generation forecast uncertainty.
- High SA demand forecast coinciding with hot weather conditions, with increased forecast uncertainty at those temperatures.
- Elevated risk of generation performance issues during hot weather conditions.
- Lack of available options to ensure power system reliability (up to load shedding) should a credible contingency event occur.
- The notice period required in respect of the only unit available for direction (refer to Section 4.2).

After assessing these factors, AEMO considered that it may not have been able to avoid the need for load shedding if a credible contingency event occurred. By the time this conclusion was reached, the latest time to intervene was already imminent based on the lead time of the only available unit for a direction (Pelican Point GT12[2]). Accordingly, AEMO decided to issue a direction to Pelican Point GT12 for the maintenance of power system reliability.

[2] Pelican Point power station is registered as an aggregated unit consisting of two combined cycle gas turbines (GT11 and GT12) and a steam turbine (ST18). Each combined cycle GT had a minimum load of 160 MW which includes output for a whole GT and half a ST.

4.2 AEMO's determination that a market response would not have avoided the direction and the determination of the latest time for issuing the direction

Under NER clause 4.8.5A(a) and (c), AEMO must notify the market of an anticipated power system security or reliability issue and the latest time for a market response to address that issue before AEMO would use directions to intervene in the market.

On 1 March 2017, AEMO issued a number of Market Notices[3] advising the market of the forecast LOR1 conditions in SA. AEMO had contacted all Scheduled Generators with thermal generating units earlier in the morning to confirm their availability for 1 March 2017 and to determine the latest time to intervene.

AEMO considered a market response would not have avoided the need to direct, because all available scheduled generating units in SA (other than Pelican Point GT12 and Torrens Island A unit 1) were already bid into the market. Torrens Island A unit 1 was on an outage with a recall time of 168 hours, leaving Pelican Point GT12 being the only scheduled generating unit identified for a direction.

AEMO had already contacted ENGIE earlier in the morning at 0824 hrs on 1 March 2017 to seek generation availability for Pelican Point GT12 and to determine the latest time to intervene. ENGIE had advised AEMO that Pelican Point GT12 would be available under an AEMO direction with a synchronisation time of 1 hour and another 30 minutes to get to minimum load.

Following the assessment of increased risk factors described in Section 4.1, AEMO determined that it may not be able to maintain power system reliability between 1730 hrs and 1830 hrs if a credible contingency event occurred. Taking ENGIE's advice into consideration, AEMO then determined it was necessary to intervene immediately. At 1639 hrs, AEMO directed ENGIE to synchronise and dispatch Pelican Point GT12 to its minimum load of 160 MW. At that time, GT12 was offline and the output of Pelican Point Power Station was from the combined output of GT11 and ST18 (220 MW). A market notice (MN 57771) was published immediately afterwards notifying the market about the direction.

4.3 Processes implemented by AEMO to issue the direction

AEMO's procedures for the management of directions are contained in System Operating Procedure SO_OP 3707 "Intervention, direction and Clause 4.8.9 Instructions", Section 5[4].

The procedure requirements are summarised below, together with a description of the process AEMO followed in relation to each requirement for the direction on 1 March 2017.

I. *Publish a Market Notice of the possibility that AEMO might have to issue a direction or clause 4.8.9 instruction so that there is an opportunity for a response from Registered Participants to alleviate that need.*

   AEMO only published Market Notices advising the market of the forecast[5] and actual[6] LOR1 conditions in SA. No Market Notices were published advising about the possibility of an intervention, as an LOR2 condition was not indicated in PD PASA.

   It was only after all of the coincident risks became apparent and AEMO had an opportunity to assess their potential impact on system reliability that a need for intervention was confirmed. AEMO was also aware there were no more scheduled generating units in SA available for a market response other than Pelican Point GT12. By the time AEMO had determined that intervention would be necessary, the time to intervene was imminent.

[3] MN 57761, MN 57762, MN 57765, and MN 57768,

[4] http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3707---Intervention-Direction-and-Clause-4-8-9-Instructions.pdf

[5] MN 57761, MN 57762, MN 57765 and MN 57768

[6] MN 57769

II. *Determine and publish the latest time for intervention.*

With Pelican Point GT12 being the only available option for a direction at the time, AEMO determined the latest time for intervention according to the notified lead time of Pelican Point GT12 (1.5 hrs). AEMO did not publish a Market Notice for the latest time for intervention because, based on the advised lead time, there was insufficient time to do so once AEMO had determined that intervention would be necessary.

III. *Determine which Registered Participant should be the subject of a direction or clause 4.8.9 instruction.*

In anticipation of the tight supply-demand situation on 1 March 2017, Pelican Point GT12 was the only option for a direction to avoid the need for load shedding if a credible contingency event occurred. ENGIE was therefore the only Registered Participant that could reliably be directed to provide additional generation.

IV. *If a direction is to be issued, if reasonably practicable, the determination will aim to minimise the effect on interconnector flows and minimise the number of Affected Participants.*

AEMO seeks to minimise the number of Affected Participants by ‘counter-action’[7] on generating units within the Directed Participant’s portfolio. At the time of the direction on 1 March 2017, AEMO issued a counter-action instruction to Pelican Point GT11 and ST18. The combined output from GT11 and ST18 reduced to its minimum loading of 160 MW from its original output of 220 MW.

V. *Issue a direction or clause 4.8.9 instruction verbally to the relevant Registered Participant, confirming whether it is a direction or clause 4.8.9 instruction.*

AEMO control room logs indicate a verbal direction was given to ENGIE at 1639 hrs on 1 March 2017 for Pelican Point GT12 to synchronise and dispatch to minimum load.

VI. *Issue a Participant Notice confirming the direction or clause 4.8.9 instruction.*

AEMO issued a Participant Notice PN 57772 to ENGIE at 1649 hrs on 1 March 2017 advising of a direction in accordance with clause 4.8.9 of the NER.

VII. *Issue a Market Notice advising that AEMO has issued a direction or clause 4.8.9 instruction.*

AEMO issued MN 57771 at 1648 hrs on 1 March 2017 advising the market that a direction in accordance with clause 4.8.9 of the NER had been issued to a participant in the SA region. The direction was expected to stay in place until 2200 hrs on 1 March, catering for the minimum run time of 4 hours for Pelican Point GT12. Note that MN 57771 was issued to correct an earlier Market Notice (57770), which was issued at 1643 hrs with an incorrect direction issue time.

VIII. *Revoke the direction or clause 4.8.9 instruction as soon as it is no longer required.*

The actual LOR1 condition ceased at 1825 hrs (MN 57779) and the potential inability to maintain reliability if a credible contingency occurred did not eventuate as wind generation dispatched higher than was forecast at the time of the direction. At 1832 hrs, AEMO contacted ENGIE to ask whether the Pelican Point GT12 direction could be ended earlier than the expected end time of 2200 hrs

[7] In accordance with NER clause 4.8.9(h)(3), AEMO may apply a counter-action constraint on a selected market participant to minimise the number of affected participants during an AEMO Intervention Event.

specified in MN 57771. There was also a possibility ENGIE may not have been able to comply with the direction due to the trip of ST18[8].

At 1908 hrs, ENGIE contacted AEMO and agreed to end the direction earlier. ENGIE advised that once GT11, GT12, and ST18 were back in stable mode after the trip of ST18, GT11 would be taken out of service in place of GT12, to allow GT12 to complete minimum run time.

At 1925 hrs on 1 March 2017, AEMO revoked the Direction when GT11 came out of service and GT12 remained in service for normal market operation. MN 57782 was issued advising the market of the direction cancellation.

4.4 Basis for AEMO not following any or all processes under clause 4.8 prior to direction

AEMO considers that it followed all applicable processes under NER clause 4.8 for this direction apart from:

- The requirement to publish a notice to the market of the possibility that AEMO may issue a direction so that there is an opportunity for a market response (NER clause 4.8.5A(a)).
- The requirement to determine and publish the latest time for AEMO intervention (NER clause 4.8.5A(c)).

AEMO did not publish these notices because:

- In the case of clause 4.8.5(a), AEMO did not consider issuing a notice prior to the time at which it determined intervention was necessary. In part because the need to intervene had not been established, and in part because the purpose of such a notice (to seek a market response) could not have been achieved as Pelican Point GT12 was the only option available and not already dispatched in the market.
- In the case of clause 4.8.5(c), AEMO did not form the view that intervention was necessary until the time for intervention had passed.

Refer to Section 4.2 for more details.

AEMO has reviewed its interpretation of these rules and the adjusted process is further explained in Section 7.

4.5 Effectiveness of responses to AEMO inquiries under clause 4.8.5A(d)

As noted in Section 4.2, AEMO contacted all Scheduled Generators with thermal generating units in SA to seek their availability for 1 March 2017. All Scheduled Generators other than ENGIE confirmed that all of their capacity had either been made available for 1 March already or was on outage, and there was no additional capacity available for direction.

AEMO is satisfied that all Generators responded to the inquiries made under 4.8.5A(d) in a timely manner.

[8] ST18 tripped at 1742 hrs on 1 March 2017.

4.6 Notice from Registered Participants of inability to comply with the direction

At 1639 hrs on 1 March 2017, ENGIE was directed to synchronise Pelican Point GT12 and dispatch to minimum load as soon as possible. GT12 synchronised at 1732 hrs but was unable to follow dispatch targets to minimum load due to a trip of ST18 at 1742 hrs.

In order for GT11 and GT12 to come up to minimum load, ENGIE advised the AEMO control room that Pelican Point Power Station would need to reduce total output to approximately 27 MW for ST18 to re-start (below original availability of 220 MW).

Both GT11 and GT12 increased to minimum load of 160 MW each at around 1905 hrs, but the direction was cancelled at 1925 hrs because the direction was no longer required[9].

[9] Refer to Section 4.3 VIII for more details regarding direction cancellation.

5. APPLICATION OF INTERVENTION PRICING

Under NER clause 3.9.3(b), AEMO must set the dispatch price and ancillary service prices for an intervention price dispatch interval at the value which AEMO, in its reasonable opinion, considers would have applied for that dispatch interval in the relevant region had the intervention event not occurred (intervention pricing).

AEMO's relevant procedures for intervention pricing are:

- Power System Operating Procedure SO_OP 3705 "Dispatch", section 10[10].
- Intervention Pricing Methodology[11] (the methodology and assumptions developed in accordance with NER clause 3.9.3(e)).

Under NER clause 3.9.3(f)(2), AEMO determines and publishes the prices that apply during a period of intervention in accordance with the Intervention Pricing Methodology.

Section 10 of SO_OP 3705 "Dispatch" requires AEMO to do the following:

I. *In accordance with NER Clause 3.9.3(a), "In respect of a dispatch interval where an AEMO intervention event occurs AEMO must declare that dispatch interval to be an intervention price dispatch interval".*

   a. AEMO issued MN 57774 at 1709 hrs to declare an AEMO intervention event commenced at DI ending 1640 hrs and was forecast to apply until 2200 hrs. It also declared all dispatch intervals during the AEMO intervention event to be intervention price dispatch intervals. This Market Notice advised that the direction may affect dispatch quantities for intervention pricing purposes, and that AEMO would provide an update once dispatch quantities were affected by implementing the intervention pricing constraint.

   b. AEMO issued MN 57775 at 1740 hrs (as an update to MN 57774) to advise dispatch quantities had been affected for intervention pricing purposes from DI ending 1740 hrs and were forecast to apply until the end of the AEMO intervention event.

   c. The direction ended at 1925 hrs and intervention pricing constraints were implemented to affect dispatch quantities between:

      - DI ending 1740 hrs and DI ending 1805 hrs, and
      - DI ending 1905 hrs and DI ending 1935 hrs.

      Table 2 in Section 6 sets out the process of implementing intervention pricing constraints during the direction and the resulting dispatch quantities had the direction not occurred ('what-if' outputs).

      What-if outputs were revised between the DIs ending 1855 hrs and 1905 hrs to better reflect outputs had the direction not occurred. These DIs were revised due to intervention pricing constraints being invoked two DIs later than the time which Pelican Point generation increased above the original availability of 220 MW. Note that only the what-if outputs were revised but not the regional reference prices (RRP).

[10] http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3705---Dispatch.pdf

[11] https://www.aemo.com.au/-/media/Files/PDF/Intervention-Pricing-Methodology-October-2014.pdf

II. *AEMO may initiate 'intervention' or 'What If' pricing if the RRN test*[12] *is passed. If the RRN test is passed and AEMO applies intervention pricing, NEMDE will do an intervention price run after completion of the dispatch or outturn run.*

The regional reference node (RRN) test was met for this direction, meaning that a direction given in respect of plant at the RRN would have avoided the need for the direction (NER clause 3.9.3(d)).

The central dispatch process has been automated to apply the Intervention Pricing Methodology into the intervention pricing run to determine the prices in accordance with 3.9.3(b).

[12] The RRN test is reflected in NER clause 3.9.3(d)

6. CHANGES TO DISPATCH OUTCOMES DUE TO THE DIRECTION

On 1 March 2017, ENGIE was directed to synchronise one of its combined cycle GTs (GT12) and dispatch to minimum load of 160 MW. The direction was required to maintain power system reliability in SA on 1 March 2017 due to the potential for load shedding on the occurrence of a credible contingency event.

Table 1 and the blue line in Figure 1 show the actual output (Initial MW) for Pelican Point in the dispatch run. Table 2 and the black line in Figure 1 show the output for Pelican Point had the direction not occurred (what-if run).

The compensable period when dispatch quantities were affected for intervention pricing purposes is between the DIs ending 1855 hrs and 1925 hrs. AEMO determined this was the period when actual output in the dispatch run for Pelican Point Power Station was dispatched above the what-if output during the direction period. Additional generation of around 50.37 MWh was dispatched as a result of the direction (refer to yellow highlighted area in Figure 1).

Table 1 Actual output (Initial MW) of Pelican Point in the Dispatch run during direction

Dispatch Intervals	Actual output (Initial MW) of Pelican Point in the Dispatch run
Between DI ending 1640 hrs and 1735 hrs	I. After AEMO issued the direction at 1639 hrs, GT12 was in the process of synchronising. II. GT11 and ST18 continued to generate at a combined output of less than or equal to 220 MW (original availability had the direction not occurred).
For DI ending 1740 hrs	I. GT12 synchronised and the combined output of Pelican Point power station (GT11, GT12 and ST18) should increase generation to 320 MW[13]. II. However, ST18 tripped at 1742 hrs. The combined output of Pelican Point power station could not move to 320 MW and remained at or below 220 MW.
Between DI ending 1745 hrs and 1835 hrs	In order to restore ST18 after the trip and for GT11 and GT12 to be at minimum load, ENGIE advised that total output for Pelican Point Power Station would have to reduce to below the original availability of 220 MW. For DI ending 1835 hrs, the total output for Pelican point was reduced to around 27 MW to restart ST18.
Between DI ending 1840 hrs and 1850 hrs	ST18 was restored and both GT11 and GT12 were moving towards minimum load with a combined output below the original availability.
Between DI ending 1855 hrs and 1915 hrs	Both GT11 and GT12 were either moving towards minimum load with a combined output above the original availability or generating at minimum load. Therefore, having an output between 220 MW and 320 MW.
Between DI ending 1920 hrs and 1925 hrs	I. GT11 reduced generation and came out of service at 1925 hrs. II. This was agreed between AEMO and ENGIE as the direction was no longer needed. ENGIE advised to take GT11 out in place of the directed GT12 as GT12 needed to complete minimum runtime.

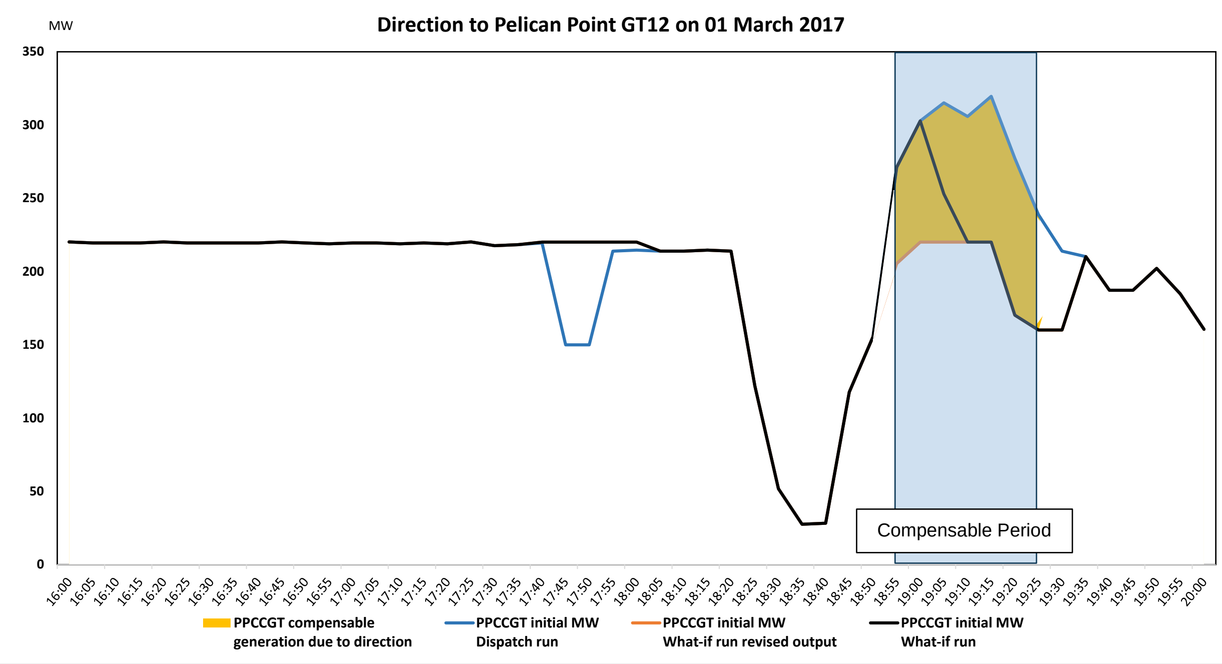
Table 2 Output (Initial MW) of Pelican Point in the What-if run during direction

Dispatch Intervals	Output (Initial MW) of Pelican Point in the What-if run when dispatch quantities were affected for intervention pricing purposes
Between DI ending 1740 hrs and 1805 hrs	The intervention pricing constraint commenced in DI ending 1740 hrs which was as soon as practical after the directed unit (GT12) synchronised at 1732 hrs. However, ST18 tripped at 1742 hrs, and the intervention pricing constraint was revoked at DI ending 1805 hrs as ENGIE was unable to comply with the direction and had to reduce output to below original availability to restore ST18.
Between DI ending 1810 hrs and 1850 hrs	Dispatch quantities were not affected for intervention pricing purposes during this period.

13 320 MW is the summation of the minimum load for both combined cycle GTs, GT11 and GT12 (160 MW each). 160 MW minimum load includes output for a whole GT and half a ST.

Dispatch Intervals	Output (Initial MW) of Pelican Point in the What-if run when dispatch quantities were affected for intervention pricing purposes
Between DI ending 1855 hrs and 1935 hrs	I. Between DI ending 1905 hrs and 1935 hrs: Intervention pricing constraint was invoked again for DI ending 1905 hrs when ST18 returned to service and revoked at DI ending 1935 hrs. The intervention pricing constraint was invoked 2 DIs later than the time at which Pelican Point generation increased above the original availability of 220 MW at DI ending 1855 hrs. II. Between DI ending 1855 hrs and 1905 hrs: As a result of invoking the intervention pricing constraint 2 DIs late, AEMO revised the what-if output for Pelican Point Power Station between DI ending 1855 hrs and 1905 hrs to better reflect outputs had the direction not occurred. (Refer to orange line in Figure 1) III. Between DI ending 1930 hrs and 1935 hrs: The direction ended at 1925 hrs and intervention pricing constraints should have been revoked for DI ending 1925 hrs, but remained in place for an additional 2 dispatch intervals. AEMO determined the affected dispatch quantities for DIs ending 1930 hrs and 1935 hrs were not compensable.

Figure 1 Impact between dispatch run and what-if run for Pelican Point on 1 March 2017



Under NER 3.8.1(b)(11), AEMO is required, as far as reasonably practicable, to minimise the market impact of its direction in terms of the number of Affected Participants and changes to interconnector flows[14]. Counter-action was applied during this direction by reducing generation for Pelican Point GT11 to minimum load of 160 MW. There were no Affected Participants during the compensable period[15] as a result of the SA direction.

[14] AEMO's power system operating procedure SO_OP 3707 "Intervention, Direction and Clause 4.8.9 Instructions" describes this objective, but does not link it to NER clause 3.8.1(b)(11). In practice, AEMO meets the objective by selecting generating units located in the same region as the directed generation (and, if possible, belonging to the same participant) and then constraining the dispatch of the selected generating units by an equal and opposite amount to that of the directed generating units.

[15] In accordance with NER clause 3.12.2(b), an Affected Participant would only be compensated for TIs when the dollar impact exceeds $5,000.

7. CONCLUSIONS AND FURTHER ACTIONS

AEMO has reviewed the direction issued to ENGIE in relation to Pelican Point GT12 on 1 March 2017 and the circumstances surrounding this direction. AEMO assessed its compliance with the applicable procedures and processes for determining who to issue the direction to, market notification, and the application of intervention pricing.

While AEMO is satisfied that the procedure and process requirements were largely met, two issues were identified for this direction event.

I. Market Notices were not issued advising of the possibility of an intervention or the latest time for intervention prior to the issue of the direction. AEMO has reviewed its interpretation of these rule requirements and has adjusted its processes to provide for publication of these notices earlier where possible, and irrespective of the potential for market response.

II. The incorrect timing for invoking and revoking the intervention pricing constraints (Refer to Table 2 in Section 6 for more detail) which led to:

- What-if outputs being revised between DI ending 1855 hrs and 1905 hrs, and
- Affected dispatch quantities for DIs ending 1930 hrs and 1935 hrs were determined not compensable.

AEMO has since undertaken operator refresher training to reinforce the correct process for invoking and revoking constraints in the System Outlook for the Market Management System (SOMMS).

ABBREVIATIONS

Abbreviation	Expanded name
DI	Dispatch Interval
TI	Trading Interval
LTTI	Latest Time to Intervene
MN	Market Notice
PN	Participant Notice
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rules
RRN	Regional Reference Node
SA	South Australia
LOR	Lack of Reserve
AEMO	Australian Energy Market Operator
AEST	Australian Eastern Standard Time
PASA	Projected Assessment of System Adequacy
PD PASA	Pre-dispatch Projected Assessment Of System Adequacy
RRP	Regional Reference Price
SOMMS	System Outlook for the Market Management System