BLACK SYSTEM SOUTH AUSTRALIA 28 SEPTEMBER 2016

THIRD PRELIMINARY REPORT

Published: **December 2016**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this further preliminary report as part of its review of the Black System event in South Australia on Wednesday 28 September 2016, under clauses 3.14 and 4.8.15 of the National Electricity Rules (NER) and as a further step in reporting under the NER.

The observations in this report may be updated as further investigations are conducted.

The information in this report is current as of 0900 hrs on Wednesday, 7 December 2016.

Disclaimer

AEMO has been provided with preliminary data by Registered Participants as to the performance of some equipment leading up to, during, and after the Black System event. In addition, AEMO has collated information from its own systems. The information provided by Registered Participants and collated from AEMO's own systems is preliminary information only. Any analysis and conclusions in these findings are also preliminary in nature.

While AEMO has made every effort to ensure the quality of the information in this update report, its investigations are incomplete and the findings expressed in it may change as further information becomes available and further analysis is conducted. AEMO will publish its full final report after completing its review as required by the NER.

Any views expressed in this update report are those of AEMO unless otherwise stated, and may be based on information given to AEMO by other persons.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this update report:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this update report; and,
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this update report, or any omissions from it, or for any use or reliance on the information in it.

NER TERMS, ABBREVIATIONS, AND MEASURES

This report uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings apply in this report unless otherwise specified.

Abbreviations

Abbreviation	Expanded name
AC	Alternating Current
AEMO	Australian Energy Market Operator
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AGC	Automatic Generation Control
BOM	Bureau of Meteorology
CB	Circuit breaker
CC	Cloud-to-cloud (lightning strike)
CCGT	Closed cycle gas turbine
CG	Cloud-to-ground (lightning strike)
DC	Direct Current
DI	Dispatch interval
DNSP	Distribution Network Service Provider
EMMS	Electricity Market Management System
ESCOSA	Essential Services Commission of South Australia
FCAS	Frequency control ancillary services
FPSS	Future Power System Security (program)
GIC	Geomagnetic Induced Current
GT	Gas Turbine
HV	High Voltage
HVDC	High Voltage Direct Current
HYTS	Heywood Terminal Station
I/S	In Service
LBSP	Local Black System Procedure
LV	Low Voltage
LVRT	Low Voltage Ride Through
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMOC	National Electricity Market Operations Committee
NER	National Electricity Rules
NSP	Network Service Provider
O/S	Out of Service
POD	Power Oscillation Damper
PSSWG	Power System Security Working Group
PTL	Port Lincoln
PV	Photovoltaic

Abbreviation	Expanded name
QPS	Quarantine Power Station
ROCOF	Rate of Change of Frequency
SA	South Australia
SAPN	South Australian Power Networks
SCADA	Supervisory Control and Data Acquisition
SCR	Short Circuit Ratio
SESS	South East Substation
SPAR	Single phase auto-reclosing
SRAS	System Restart Ancillary Service
SRS	System Restart Standard
STATCOM	Static compensator
SVC	Static Var Compensator
TIPS	Torrens Island Power Station
TNSP	Transmission Network Service Provider
UFLS	Under frequency load shedding
WF	Wind farm
WSCR	Weighted Short Circuit Ratio

Measures

Abbreviation	Unit of Measure
Hz	Hertz (cycles per second)
km/h	Kilometres per hour
kV	Kilovolt
kWhr	Kilowatt hour
ms	Milliseconds
MVA	Mega volt amps
MVAR	Mega volt amps reactive
MW	Megawatts
MWhr	Megawatt hour
MWs	Megawatt second
MW/s	Megawatts per second (rate of change)
pu	Per unit

INTRODUCTION

This report is divided into the following sections:

- **Pre-event** – the status of the power system in SA prior to the Black System and a summary of NER provisions related to AEMO pre-event decisions on system security.
- **The events resulting in the Black System** – the sequence of events on the power system that occurred in the SA region of the National Electricity Market (NEM) in the 87 seconds before system shutdown at 16:18:16.
- **Restoration** – the sequence of steps taken to restore normal power supply to all SA electricity consumers.
- **System Restart Ancillary Services (SRAS)** – the sequence of events and actions taken relating to provision of SRAS in SA during the Black System.
- **Market suspension and subsequent operation** – a summary of the provisions in the NER related to Market suspension in the NEM, and of the sequence of events from the system shutdown to lifting of Market suspension on 11 October 2016 at 2230 hrs.
- **Preliminary recommendations** – for action proposed by AEMO as a result of this investigation
- **Next stage of investigations** – the proposed next steps for further investigation and reporting.

References to times in this report, unless otherwise specified, are market time (Australian Eastern Standard Time), not local time in SA, nor local time in Victoria.

EXECUTIVE SUMMARY

AEMO has published two preliminary reports that articulate the sequence of events before, during, and after the South Australia (SA) region Black System event on 28 September 2016. This third report provides a consolidated view of all information published to date, together with further insight into AEMO's pre-event planning and system restart process in South Australia, and power system and market operations during the Market suspension.

The particular event was initiated by the loss of three transmission lines involving a sequence of faults in quick succession tripping generators offline. Such extreme events occur rarely and are classified as 'non-credible' in the National Electricity Market (NEM). A number of wind turbine generators in the mid-north of SA exhibited a reduction in power or disconnected as the number of faults grew. AEMO was not aware of the protective feature of these generating units that caused these power reductions, and has taken action to ensure the limitations are known and appropriately managed.

While extreme events will occur from time to time, testing the wider resilience of the grid system, this report outlines preliminary recommendations for further analysis to mitigate the risk of similar major supply disruptions occurring in SA.

A fourth and final report, due to be published in March 2017, will provide more detailed information from these investigations, including information regarding generator performance standards. Where these wider investigations indicate changes are required to processes and systems, the March report will outline these final recommendations.

In this report, AEMO outlines the importance of practical measures to be implemented to:

- Reduce the risk of islanding of the SA region.
- Increase the likelihood that, in the event of islanding, a stable electrical island can be sustained at least in part of SA.
- Improve performance of the system restart process.
- Improve market and system operation processes required during periods of Market suspension.
- Address other technical issues highlighted by this investigation.

Similar to its previous two reports, AEMO has structured this report into the core stages of the Black System event – pre-event, event, restoration, and Market suspension/resumption. Preliminary recommendations are in Chapter 7 and are summarised in this executive summary.

The significance of the event and the intensity of review has brought to the fore a range of broader issues associated with the changing generation mix across the NEM. The generation mix now includes more non-synchronous and inverter-connected plant, which has different characteristics to conventional plant and uses active control systems to ride through disturbances.

The growing proportion of this type of generating plant within the generation portfolio is leading to more periods with low inertia and low available fault levels, hence a lower resilience to extreme events.

These technical challenges need to be managed with the support of efficient and effective regulatory and market mechanisms, to ensure the most cost-effective measures are used. AEMO is continuing its contribution to the resolution of all these matters, working in association with its stakeholders. This includes our Future Power System Security (FPSS) program and collaborative engagement with the Australian Energy Market Commission (AEMC) and the Finkel review.

While this report focuses on the specifics of the SA Black System event, it highlights a number of challenges and measures relevant to broader considerations of how the changing power system responds to extreme events.

Pre-event

AEMO has access to multiple sources of weather information, including from Weatherzone for aggregated weather advice, the Bureau of Meteorology (BOM), Indji Watch for bushfires satellite coverage, and Global Positioning and Tracking Systems (GPATS) for lightning strikes mapping.

On the morning of Wednesday 28 September 2016, weather warnings were issued by Weatherzone and received by AEMO's NEM Control Room, stating a severe storm with heavy lightning and damaging winds across SA was approaching. Later in the day, the wind warning was updated to a destructive level moving from a predicted maximum wind speed from 120 to 140 km per hour (km/h).

AEMO assessed the risks to the power system in SA and the likelihood of damage to the network or wind turbines cutting out due to high winds. Based on an assessment of information available at 0830 hrs (forecast winds of 50–75 km/h and gusts of up to 120 km/h), it was determined that there was no action to be taken by AEMO to reclassify lines as a result of the weather warnings, due to the following:

- No advice had been received from ElectraNet that the forecast wind speeds represented an abnormal threat to the transmission system.
- No double circuit transmission lines in South Australia were vulnerable to lightning.
- High winds were expected to reduce the output of some wind farms but, based on prior experience, the reduction in output could be expected to occur gradually, and the expected loss of output could be accommodated using the spare capacity on the Heywood Interconnector already set aside to manage credible contingency events.
- AEMO was not aware that some wind farms may not be capable of riding through multiple successive faults on the network.

The BOM released a report on 14 November 2016[1], indicating that tornadoes with wind speeds in the range of 190–260 km/h had occurred in a few areas. These speeds were well above the maximum wind speeds forecast before the event. The weather warnings did not forecast the formation of tornadoes.

During the period of the event, two tornadoes almost simultaneously damaged a single circuit 275 kilovolt (kV) transmission line and a double circuit 275 kV transmission line, some 170 km apart.

Preliminary recommendations include:

- AEMO to review and implement a more structured process for reclassification decisions when faced with risks due to extreme wind speeds.
- AEMO to assess the risks of when wind speeds are forecast to exceed protection settings on wind turbines, which would lead to 'over-speed cut-outs'.
- AEMO to work with stakeholders to determine whether the NEM Control Room can develop a more sophisticated forecasting system to predict extreme wind conditions, including tornadoes.

Event

Largely as a result of tornado damage to the transmission network, there were six voltage dips over a two-minute period. Wind turbines have protective features that result in a significant power reduction if they experience more than a pre-set number of voltage dips within a two-minute period. This information was previously unknown to AEMO. It was not provided to AEMO in the NEM connection process, nor is it included in AEMO's operational and planning modelling.

Latest information included within this report outlines a reduction in wind farm output of 456 megawatts (MW) from nine wind farms north of Adelaide over a period of less than seven seconds. Further investigation of this reduction is required, with a review of the adequacy of relevant performance standards to be included in AEMO's final event report.

[1] Bureau of Meteorology. *Severe thunderstorm and tornado outbreak South Australia 28 September 2016*, 14 November 2016. Available at: http://www.bom.gov.au/announcements/sevwx/.

The reduction in wind farm output resulted in a significant increase in flow through the Heywood Interconnector. Approximately 700 milliseconds (ms) after the reduction of output from the last of these wind farms, the flow on the Victoria–SA Heywood Interconnector reached such a level that it activated a special protection scheme that tripped it offline. The SA power system then became separated (“islanded”) from the rest of the NEM, and the entire supply to the SA region was then lost due to a severe supply/demand imbalance (“Black System”).

As a result of this sequence of events, AEMO makes the following preliminary recommendations:

- AEMO to work with ElectraNet to determine the feasibility of developing a system protection scheme which, in response to sudden excessive flows on the Heywood Interconnector or serious events within SA, would initiate load shedding or generation tripping, with a response time fast enough to prevent separation.
- AEMO to investigate potential measures that could help manage a severe imbalance between supply and demand in the event of islanding SA, resulting in a very high rate of change in frequency beyond what can be managed currently.
- AEMO to investigate the level of risk to power system security posed by a single credible fault in an area where there is a concentration of wind farms, and develop measures to manage the risk.

Restoration

Immediately following the Black System, the first requirement for AEMO and ElectraNet was to assess the state of the transmission network and then for ElectraNet to make safe the damaged transmission lines that were presenting a potential threat to public safety.

After an assessment of the sections of the network that were safe to energise, the restart proceeded, in accordance with a system restart plan that involved the use of restart capability from one of the two contracted SA system restart ancillary service (SRAS) generating units and restoration of supply from the Victoria region via the Heywood Interconnector.

The relevant generating unit successfully started, but was unable to supply power at the level required to fully restart a major generating unit. Restoration therefore proceeded only via the Heywood Interconnector. By 2030 hrs, about 40% of the load in SA capable of being restored had been restored. By midnight, 80 to 90 % of the load that could be restored had been restored. The remaining load was gradually restored as transmission lines were repaired, and all load was restored by 11 October.

The time to restore the majority of the load was in line with restoration times experienced in other recent power system restorations in Australia and elsewhere around the world.

System restarts are rare events, and therefore each event represents a valuable learning experience for both AEMO and the industry. The following recommendations aim to improve the speed of restoration, without increasing risk, should another Black System occur.

- AEMO, together with the South Australian System Restart Working Group, to review the process in detail to determine process efficiencies. These learnings should be shared across all Australian jurisdictions.
- Any differences between SRAS test plans and the restart process set out in the system restart plan and associated local Black System procedures to be identified and explained, to ensure that the test simulates, as far as practical, the conditions that will be encountered in a real restart situation.
- Similarly, where the restart procedure for an SRAS source depends initially on a start of a low voltage generator, the start of this generator alone should be tested on a regular basis in addition to the annual test for the entire SRAS source.

Market suspension

At 1625 hrs on 28 September 2016, AEMO declared the NEM suspended in the SA region due to the Black System. When the Black System ended, the Market suspension was not immediately lifted due to continuing uncertainties in power system operations. At 2039 hrs on 29 September 2016, AEMO was directed by the SA Government to keep the market suspended.

During this period, AEMO continued to manage power system operations in SA. This involved, from 3 October 2016, reclassification of the loss of multiple wind farms as a credible contingency event due to the simultaneous reduction of output observed immediately prior to the Black System. As a result of this reclassification, a constraint equation was placed on the output of these wind farms. This reclassification was adjusted on a number of occasions as some wind farms increased the pre-set level for their special protection scheme. The reclassification remains in place as of 7 December 2016 for some wind farms.

The effect of the reclassification is to ensure the SA power system is operated with sufficient redundancy to cover the simultaneous loss of generation from all wind farms within the constraint equation.

During the Market suspension, AEMO implemented the required pricing mechanisms for the SA region and, in limited instances, for other NEM regions.

At 1748 hrs on 11 October 2016, AEMO was advised by the SA government that its direction for suspension of the market had been revoked. AEMO lifted the Market suspension at 2230 hrs.

A major problem identified was the lack of detailed procedures on how to operate the power system during extended periods of Market suspension, leading to the following recommendations:

- AEMO to develop detailed procedures on the differences required in power system operations during periods of NEM Market suspension, and identify if any rule changes are desirable to improve the process.
- AEMO to investigate a better approach to ensuring that the minimum stable operating levels of generating units are taken into account in the NEM dispatch process.
- AEMO to review market processes and systems, in collaboration with NEM participants, to identify improvements and any associated rule or procedure changes that may be necessary to implement those improvements.

Experience in this investigation has also identified possible improvements for future major investigations, so recommendations include:

- AEMO to develop a more structured process in consultation with NEM participants to source and capture data after a major event in a timely manner and to better co-ordinate data requests made to participants.
- AEMO to investigate with NEM participants the possibility of introducing a process to synchronise all high speed recorders to a common time standard.

Next steps

These report highlights a number of preliminary recommendations that will be further developed in AEMO's final report, due to be published in March 2017.

As part of AEMO's FPSS program, work is underway to identify and implement viable solutions for a number of technical challenges outlined in this report, to maintain power system security now and into the future.

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TABLES

FIGURES

1. REPORT OBJECTIVES AND SCOPE

This report, the third in a series, sets out AEMO's understanding of the following, at this stage of its investigation:

- Details of the Black System event and its causation chain.
- The performance of the system restart process and supply restoration.
- The performance of power system and market operations during Market suspension.
- Recommendations for further action.

The scope of this report is intended to meet the requirements of clause 4.8.15 of the National Electricity Rules (NER) for events prior to declaration of Market suspension, and of clauses 3.14.3 (c) and 3.14.4(g) of the NER for subsequent events. Specifically, the report:

- Reviews the adequacy of the provision and response of facilities or services.
- Reviews the appropriateness of actions taken to restore or maintain power system security, including how reclassification criteria were assessed and applied.
- Reports on the reason for the suspension and the effect that the suspension had on the operation of the National Electricity Market (NEM) spot market.

This report has incorporated all information from AEMO's two previous reports on this event, except where that information has now been superseded. The previous reports are:

- **Preliminary Report** – AEMO's first report, published on 5 October 2016, titled *Preliminary Report – Black System Event in South Australia on 28 September 2016* and based on information available up to 0900 hrs on Monday 3 October 2016. This report is available at http://www.aemo.com.au/Media-Centre/Media-Statement-South-Australia-Interim-Report.
- **Update Report** – AEMO's second report, published on 19 October 2016, titled *Update Report – Black System Event in South Australia on 28 September 2016* and based on information available up to 1700 hrs on Tuesday 11 October 2016. This report is available at http://www.aemo.com.au/Media-Centre/Update-to-report-into-SA-state-wide-power-outage.

2. PRE-EVENT

This section outlines the state of the power system[2] in the period leading up to the events resulting in a Black System at 1618 hrs on 28 September 2016. This resulted in the loss of supply to all customers in SA (approximately 850,000 customer connections and 1,826 megawatts (MW)[3] of demand).[4]

Prior to the event:

- The electricity system in SA was in a secure operating state.
- The electricity market was operating normally.

2.1 Assessment of conditions

At 0830 hrs on 28 September 2016:

- AEMO assessed the state of the weather using available weather analysis tools.[5] Bureau of Meteorology (BOM) weather reports, at the time of this assessment, included wind speed forecasts of up to 120 km/h (gusts). The forecasts received by AEMO did not include any warnings regarding the possibility of tornadoes. Details of these weather warnings are in Appendix E.1.[6]
- AEMO noted that forecast wind conditions could reduce wind farm output where the wind speed exceeded 90 km/h, and implemented increased monitoring of wind farm performance.[7] This included comparisons between forecast and actual wind farm outputs to ensure accurate dispatch. Over-speed trips occur at the individual wind turbine level and reduce power output over several minutes. Potential over-speed reductions were adequately covered by spare capacity on the Heywood Interconnector.
- AEMO was operating the power system in accordance with the NER and procedures under the NER and was covering the loss of certain groups of wind farms as a credible contingency event, where these wind farms were connected to the grid via a single transmission line.[8] This meant the Heywood Interconnector would remain stable for the loss of 260 MW of generation within SA, and action would then be required by AEMO to bring the flow on the interconnector back to the secure limit within half an hour. There was sufficient reserve generating capacity within SA to achieve this if needed.
- AEMO assessed the potential impact on the transmission network due to lightning. As no double circuit transmission lines in SA were classified as 'vulnerable' to lightning[9], the potential presence of lightning did not warrant the loss of those lines being reclassified from a non-credible contingency event to a credible contingency event. The unexpected disconnection of a single circuit transmission line, for any reason, is always treated as a credible contingency event.
- AEMO assessed conditions that could impact the Heywood Interconnector. As both transmission circuits comprising the Heywood Interconnector were in service, the loss of both lines was considered a non-credible contingency event. The lines had not been classified as 'vulnerable' due to lightning, and AEMO had not received advice regarding abnormal risks to the transmission network due to the forecast weather conditions.
- AEMO had not been informed by ElectraNet or SA Generators of any circumstance which could have adversely affected the secure operation of the power system or their equipment under these

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[2] Appendix A illustrates the SA 275 kV transmission network before the event.
[3] Numeric value was given as 1,895 MW in the *Preliminary Report – Black System Event in South Australia on 28 September 2016*. The minor variation is due to the data timestamp, which has been aligned at 1618 hrs.
[4] Further details relating to the roles and responsibilities of everyone involved in the event, as well as key power system security concepts such as 'credible contingency event', 'non-credible contingency event', and 'vulnerable', are in Appendix F.
[5] AEMO's sources of information include Weatherzone, the BOM, and Indji Watch (Global Positon and Tracking Systems Pty Ltd (GPATS)).
[6] Since 1 January 2006, warnings of damaging winds (wind gusts exceeding 90 km/hr) have been issued in SA on 617 days, and warnings of destructive winds (wind gusts exceeding 124 km/hr) have been issued in SA on 29 days.
[7] Under high wind speed or high ambient temperature conditions, wind generation can shut down to protect wind turbines from damage.
[8] The largest such contingency at the time in South Australia were the group Lake Bonney wind farms (approximately 260 MW).
[9] See section 11.4.1 of AEMO's Power System Security Guidelines, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.

forecast conditions (advice to AEMO of the existence of such risks is standard practice under clause 4.8.1 of the NER).[10]

- AEMO understood that all wind farm turbines were capable of riding through multiple faults provided these faults were within the size and duration parameters specified in generator performance standards[11] that would have ensured they cleared within the maximum clearance times set out in the System Standards.[12]

At around 0930 hrs, AEMO discussed the approaching weather with ElectraNet:

- ElectraNet advised that several outages had been cancelled, several more outages were expected to be returned to service early, and field crews were on standby if required.
- No issues were raised by ElectraNet about abnormal risks to the transmission network. Across the NEM, the transmission system has had a history of successfully withstanding storms with maximum gust wind speeds of 120 to 140 km/h without major incidents. The lack of any advice from ElectraNet of additional risks to its transmission network under these forecast conditions was not inconsistent with the historical performance of the grid.[13]

In accordance with the NER and AEMO's procedures under the NER, AEMO:

- Concluded there was insufficient justification to reclassify the loss of multiple transmission circuits, including the two circuits that constitute the Heywood Interconnector, or any additional multiple generating units, as a credible contingency event.
- Accordingly, placed no additional constraints on the operation of the Victorian and SA transmission network prior to the events of 28 September 2016.

AEMO's assessment was that under the NER, in the absence of advice as to specific threats to power system security, it had no obligation or authority to take further action to maintain the secure operation of the power system.

2.2 Management of power system security

AEMO has power system security responsibilities as set out in Chapter 4 of the NER. A detailed summary is in Appendix F. At a high level:

- AEMO manages the NEM power system from two control rooms in different states that function as a single virtual control room. System management is a minute-by-minute activity that relies on extensive use of large real-time data processing systems.
- AEMO manages the power system to an N-1 standard, meaning that any single element (generator, transmission line, etc.) can be suddenly lost without system parameters breaching limits. These events are termed credible contingency events, because their occurrence is reasonably possible in the normal running of the power system.
- When the power system is operating to this N-1 standard, it is in a secure operating state.
- If a credible contingency event occurs, AEMO seeks to restore the system to a secure operating state within 30 minutes by adjusting plant settings and power flows.
- Events beyond the N-1 standard, such as the coincident loss of multiple generating units or transmission lines, are termed non-credible contingency events.
- AEMO can reclassify non-credible contingency events as credible contingency events if circumstances increase the risk of their occurrence. Common examples of reclassification include lightning in the vicinity of transmission lines known to be vulnerable to lightning, or bushfires crossing easements that contain multiple transmission lines.[14] Reclassification usually requires AEMO to apply additional constraints to the transmission network, and this can result in changes to

[10] Refer to Appendix F.11 for further details on this requirement.
[11] Refer NER S5.2.5.5.
[12] The System Standards are detailed in Schedule 5.1a of the NER, specifically, clause S5.1a.8 of the NER.
[13] ElectraNet later advised AEMO that, prior to the event, it did not consider that there was an increased risk of multiple single circuit or double circuit lines tripping.
[14] See Appendix F for definitions.

generation dispatch, which may limit the ability of individual plant to generate electricity and may increase regional energy prices.

- AEMO has overall responsibility for management of power system security, but works very closely with Market Participants and Network Service Providers (NSPs) to achieve this. AEMO relies on the assistance and cooperation of these parties to stay informed about the state of the power system and any anticipated risks.

2.3 System configuration

Pre-event operational demand[15] in SA was being supplied by a combination of thermal (synchronous) generation, wind generation, and imports from Victoria across both the Victoria to SA (Heywood) AC interconnection and (Murraylink) DC interconnection.

A summary of the generation mix prior to the event is outlined below.

Figure 1 SA generation mix pre-event

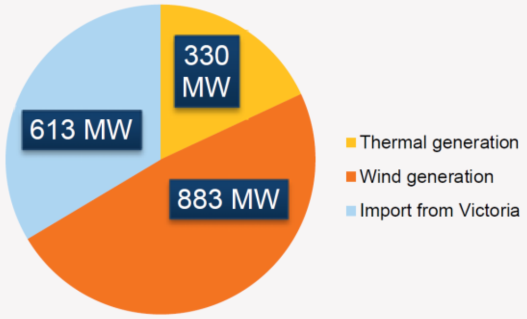


Table 1 below sets out the output of the generators on-line at the time of the SA Black System, including the substation and lines they connect to. The combined inertia of the thermal generating units was around 3,000 megawatt seconds (MWs).

Table 1 Generators on-line

Generator	Type	Output (MW)	Substation	Lines connected
The Bluff Wind Farm (WF)	Wind	43	Belalie	Davenport–Belalie Belalie–Mokota
Clements Gap WF	Wind	14	Redhill	Redhill–Bungama Redhill–Brinkworth
Canunda WF	Wind	43	Snuggery	Snuggery–Mayurra–South East Snuggery–Blanch
Hallett WF	Wind	38	Canowie	Canowie–Mt Lock Canowie–Robertstown
Hallett Hill WF	Wind	42		
Hornsdale WF	Wind	86	Mt Lock	Mt Lock–Davenport Mt Lock–Canowie
Lake Bonney 1 WF	Wind	77	Mayurra	Mayurra–Snuggery–South East
Lake Bonney 2 WF	Wind	149		
Lake Bonney 3 WF	Wind	35		
Mt Millar WF	Wind	67	Yadnarie	Yadnarie–Middleback Yadnarie–Port Lincoln
North Brown Hill WF	Wind	85	Belalie	Davenport–Belalie Belalie–Mokota
Snowtown North WF	Wind	44	Snowtown	Snowtown–Blyth West
Snowtown South WF	Wind	65		

15 Operational demand refers to the electricity used by residential, commercial, and large industrial consumers, as supplied by scheduled, semi-scheduled, and significant non-scheduled generating units.

Generator	Type	Output (MW)	Substation	Lines connected
Waterloo WF	Wind	95	Waterloo East	Waterloo East–Waterloo Waterloo East–Robertstown
Total Wind Generation		**883**		
Ladbroke Grove Unit 1	Thermal	42	Ladbroke Grove	Ladbroke Grove–Penola West
Ladbroke Grove Unit 2	Thermal	40		
Torrens Island B PS Unit 1	Thermal	82	Torrens Island	Torrens Island–Para Torrens Island–Le Fevre Torrens Island–Magill Torrens Island–City West Torrens Island–Cherry Gardens Torrens Island–North Field Torrens Island–Kilburn
Torrens Island B PS Unit 3	Thermal	84		
Torrens Island B PS Unit 4	Thermal	82		
Total Thermal Generation		**330**		

Note: Snowtown II comprises Snowtown North and Snowtown South wind farms.

Figure 2 shows the SA total wind farm output. The variation shown is typical of the intermittent nature of wind generation. This did not create a power system security issue, as variations were well within the reserve capacity already in place to cover credible contingency events.[16] The red dashed line depicts the time of the Black System.

Immediately prior to events leading to the Black System event, total SA wind power output was decreasing at about 50 MW per minute. This relatively slow variation was not a factor in the event.

Figure 2 SA total wind farm output (semi-scheduled and non-scheduled)

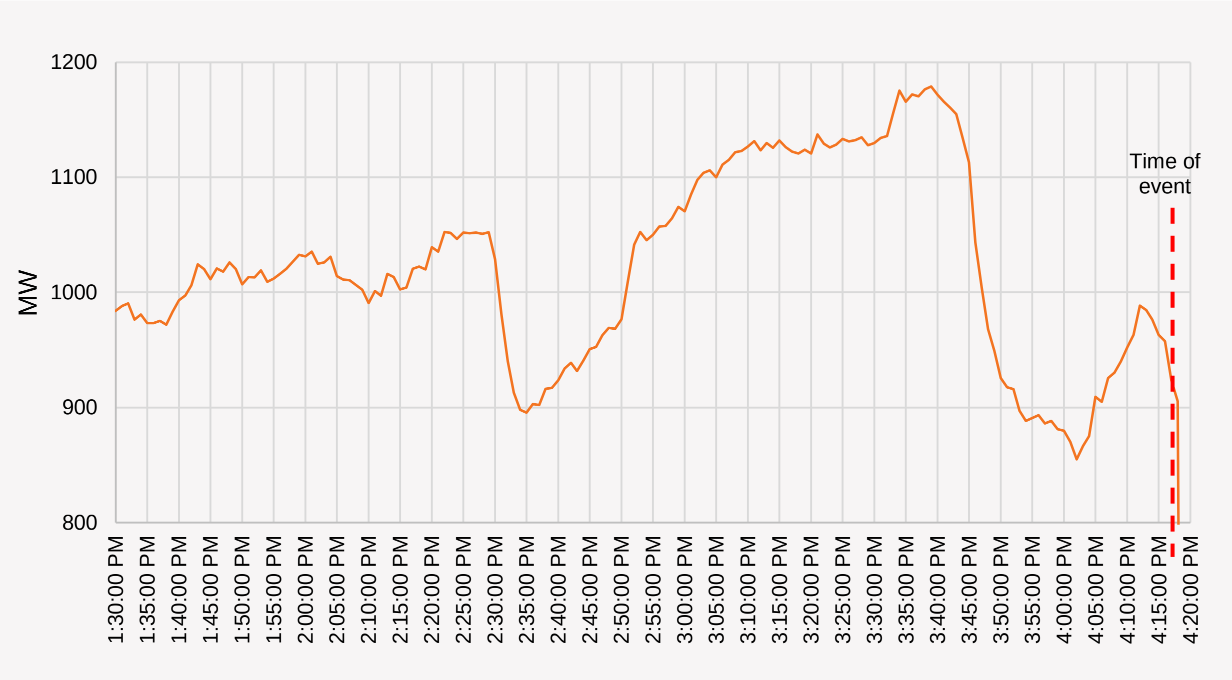


Table 2 shows SA transmission equipment which was out of service before the event or was returned to service early because of the approaching storm.

[16] For further details see Appendix E.3 of this report.

Table 2 Prior network outages

Outage	Start Date/Time	End Date/Time	Constraint set invoked	Status
PARA SVC No.2 Power Oscillation Damper (POD)	16/09/2016 17:00	25/10/2016 09:26	S-PA_SVC1-POD (Oscillatory limits)	Completed after the event.
Monash North West Bend No.2 132 kV line	24/09/2016 13:30	28/09/2016 15:33	S-MHNW_2 (thermal limits)	Returned to service early at the request of ElectraNet. Original planned return to service was 1630 hrs on 30 September 2016.
Robertstown–Waterloo East 132 kV line and associated circuit breakers (CBs)	28/09/2016 08:10	28/09/2016 11:14	S-WE_MWP4_RB (thermal limits)	Returned to service early at the request of ElectraNet. Original planned return to service was 1800 hrs on 28 September 2016.
Ardrossan West–Wattle Point Tee Dalrymple 132 kV line	22/09/2016 11:15	30/09/2016 16:08	n/a	Completed after the event.
TIPS–City West 275 kV line	24/08/2016 09:36	04/11/2016 16:30	n/a	Long-term outage.
Munno Para 1 275/66 kV XFMR and associated 275 kV CBs	22/09/2016 09:50	30/09/2016 17:06	n/a	Completed after the event.
Pimba–Olympic Dam 132 kV line	n/a	n/a	n/a	Note this line is normally out of service.

Note: Table 2 contains additional outage entries compared to the *Preliminary Report – Black System Event in South Australia on 28 September 2016*.

Action by ElectraNet to return lines to service was in accordance with normal outage management practice when faced with forecasts of adverse weather conditions.

Constraint sets and constraint equations are used by the NEM dispatch engine (NEMDE) for the secure and sustainable operation of the power system.[17] Constraint equations are used to define the mathematical restrictions translated from a physical transmission network representation. These constraint equations may be grouped into constraint sets to simplify the constraint management process.

As the physical transmission network configuration changes, due to planned or unplanned outages, constraint sets may need to be changed to represent a modified mathematical model.

The constraint sets detailed in Table 3 were in place immediately prior to the Black System.[18]

Table 3 SA constraint sets invoked pre-event

Constraint set	Date/time invoked	Date/time revoked	Description
S-NIL	12/10/2001 09:05	31/12/9999 00:00	Out = Nil, SA System Normal
F-MAIN_RREG_0300	28/09/2016 15:55	28/09/2016 16:50	Mainland Raise Regulation Requirement equal to 300 MW
S-WE_MWP4_RB	28/09/2016 08:10	28/09/2016 11:14	Out = Robertstown – MWP4 – Waterloo East 132 kV line O/S (or any line segment(s) between Robertstown – Waterloo East 132 kV O/S)
S-MHNW_2	24/09/2016 13:30	28/09/2016 15:55	Out = Monash to North West Bend line 2
S-PA_SVC1-POD	16/09/2016 17:05	29/09/2016 11:30	Out= One Para SVC POD O/S (with associated SVC I/S), (Note: with both Black Range Series caps I/S)
S-POR_CB6215	28/09/2016 08:00	28/09/2016 08:35	Outage = Port Lincoln 132 kV CB6215 (Note: applies for either Port Lincoln 33 kV CB 4637 OPEN or CLOSED)

17 Refer http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/Constraint_Formulation_Guidelines_v10_1.pdf.

18 Table 3 contains additional constraint entries, compared to those listed in the *Preliminary Report – Black System Event in South Australia on 28 September 2016*.

Constraint set	Date/time invoked	Date/time revoked	Description
I-VS_600_TEST	05/08/2016 12:00	12/12/2016 10:00	Out = NIL, Heywood VIC to SA limit of 600 MW for testing of upgraded Heywood interconnection
I-VS_650_TEST	27/09/2016 12:30	31/12/9999 00:00	Out = NIL, Heywood VIC to SA limit of 650 MW for testing of upgraded Heywood interconnection
I-VSS_820_TEST	05/08/2016 12:00	12/12/2016 10:00	Out = NIL, Heywood and Murraylink combined VIC to SA limit of 820 MW for testing of upgraded Heywood interconnection
I-VSS_870_TEST	27/09/2016 12:30	31/12/9999 00:00	Out = NIL, Heywood and Murraylink combined VIC to SA limit of 870 MW for testing of upgraded Heywood interconnection

There was no local SA Regulation frequency control ancillary services (FCAS)[19] requirement pre-event, because there was considered to be no credible risk of separation of SA from the rest of the NEM, as SA was connected to Victoria via the double circuit (Heywood Interconnector) transmission line.

This meant SA synchronous generators were operating their steam governors for constant power output (as instructed by AEMO via Automatic Generation Control system), rather than in automatic frequency control mode.

When SA is connected only via a single transmission line from Victoria, constraint equations are invoked pre-contingently to ensure sufficient regulation FCAS (both raise and lower) services are enabled in SA for a potential credible contingency event.

FCAS enables AEMO to control the frequency of the power system and ensure the system meets the frequency standards prescribed by the Reliability Panel. There are eight types of FCAS, which can be grouped into two categories: six types of contingency FCAS, and two types of regulation FCAS.[20] However, none of these services would have responded fast enough to have any effect during the events leading to separation or in stabilising the SA island after separation.

Table 4 details the constraint equations that relate to the SA system, binding between 1600 hrs and 1615 hrs. Binding constraint equations impact on dispatch by limiting flows across the transmission network, and indicate that NEMDE determined that left-hand-side controllable term/s needed to be varied to satisfy the linear constraint equation.

The table shows that there were no constraint equation violations (which indicate NEMDE could not find a viable solution)[21], indicating the power system was in a secure operating state during the pre-event timeframe.

Table 4 Constraint equation results summary

SETTLEMENTDATE	CONSTRAINTID	RHS	MARGINALVALUE	VIOLATIONDEGREE
28/09/2016 16:00	V::S_NIL_MAXG_1	591.7963	-2.2112	0
28/09/2016 16:05	S>>NIL_RBPA_WEWT	238.4796	-23.5317	0
28/09/2016 16:05	S>>NIL_TBTU_TBMO_1	631.164	-24.9706	0
28/09/2016 16:10	S>>NIL_RBTU_WEWT	252.5159	-0.2105	0
28/09/2016 16:10	S>>NIL_TBTU_TBMO_1	642.2509	-9.1477	0
28/09/2016 16:15	S>>NIL_RBPA_WEWT	240.5657	-0.2012	0
28/09/2016 16:15	S>>NIL_TBTU_TBMO_1	638.0883	-9.5003	0

[19] Regulation FCAS is enabled to continually correct the generation/demand balance in response to minor deviations in load or generation. Contingency FCAS is enabled to correct the generation/demand balance following a major contingency event, such as the loss of a generating unit or major industrial load, or a large transmission element. Contingency services are enabled in all periods to cover contingency events, but are only occasionally used (if the contingency event actually occurs).

[20] Refer http://www.aemo.com.au/-/media/Files/PDF/Guide-to-Ancillary-Services-in-the-National-Electricity-Market.pdf.

[21] Refer http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/Constraint_Formulation_Guidelines_v10_1.pdf.

The constraints in Table 4 were all NIL outage constraint equations. NIL outage constraint equations are normally invoked under normal system conditions in the absence of planned or forced outages of elements of the transmission network.

At 1600 hrs, V::S_NIL_MAXG_1 constraint equation were binding for one dispatch interval (DI) with low marginal value to manage transient stability for the loss of the largest generation block[22] in SA.

In the period 1605 to 1615 hrs, the two following NIL outage thermal constraints were binding:

- S>>NIL_RBPA_WEWT (overload Waterloo East – Waterloo 132 kV for the trip of Robertstown – Para 275 kV lines).
- S>>NIL_TBTU_TBMO_1 (overload Tailem Bend – Mobilong 132 kV line for the trip of Tailem Bend – Tungkillo 275 kV line).

The behaviour of these constraints was consistent with the system conditions at that time, including increased Hallett area wind generation and interconnector flows from Victoria flowing into the Adelaide load centre.

For the period prior to the events covered in Chapter 3, AEMO's real-time diagnostic tools confirmed the power system was in a secure operating state and the operating state did not represent a threat to power system security, based on AEMO's procedures and NER requirements..

2.4 Transmission line faults

AEMO has reviewed all transmission line faults that occurred in SA on the day of 28 September 2016. These are set out in Table 5 below.

Table 5 Transmission line faults in SA on 28 September 2016

Transmission line	Out of service	In service	Comment
Hummocks–Snowtown–Bungama 132 kV	10:31	10:31	Single phase fault.[a] Auto-reclosed.
Blyth West–Bungama 275 kV	10:35	10:35	Single phase fault. Auto-reclosed.
Blyth West–Bungama 275 kV	10:35	10:35	Single phase fault. Auto-reclosed.
Blyth West–Bungama 275 kV	10:53	10:53	Single phase fault. Auto-reclosed.
Hummocks–Snowtown–Bungama 132 kV	11:28	11:28	Single phase fault.[a] Auto-reclosed.
Hummocks–Snowtown–Bungama 132 kV	15:49	15:49	Single phase fault.[a] Auto-reclosed.
Northfield–Harrow 66 kV feeder (Distribution)	16:16:46	16:16:46	Tripped (no details). Auto-reclosed.
Brinkworth–Templers West 275 kV	16:17:33	10/10/2016 17:20	Two phase to ground fault. No auto-reclose. Damaged towers bypassed.[b]
Davenport–Belalie 275 kV line	16:17:59	16:18:00	Single phase fault. [b] Auto-reclosed.
Davenport–Belalie 275 kV line	16:18:08	10/10/2016 13:40	Single phase fault. [b] No auto-reclose (due to earlier fault), locked out. Damaged towers bypassed.
Davenport – Mt Lock 275 kV line	16:18:13	12/10/2016 19:15	Single phase fault. [b] Auto-reclosed, then locked out. Damaged towers bypassed.
Davenport–Brinkworth 275 kV line	Not known[c]	Planned for 14/12/2016	Damaged. Did not trip prior to system shutdown. [b]
Port Lincoln – Yadnarie 132 kV line	Not known[c]	Approximately 30/09/2016 21:00	Insulator damage repaired.

a Referred to as a three-phase fault in the *Update Report – Black System Event in South Australia on 28 September 2016*.
b Refer to Section 3.1.4 for more details.
c Occurred after the Black System event, hence actual time unknown.

[22] The largest such contingency at the time in SA was the group of Lake Bonney wind farms (approximately 260 MW).

The series of transmission line faults in the period from 1031 hrs to 1549 hrs did not pose significant risks, because they involved only two transmission circuits and both lines successfully auto-reclosed and remained in service.

2.5 Weather – a post-event analysis

At the time of the Black System, there were severe weather conditions in SA. A report from Weatherzone (see Appendix B), after the event, has confirmed that:

- There was an "intense low pressure system" that "brought severe weather to SA" from Wednesday 28 September 2016 until early Friday 30 September 2016.
- The low pressure system and associated pre-frontal trough and cold front "triggered especially severe thunderstorms (including tornadoes)" as it crossed SA on 28 September 2016.
- The "complex weather system affected large parts of southern and south-eastern Australia, with damaging to destructive winds, widespread thunderstorms, cloud to ground lightning strikes, damaging hail, and heavy rainfall (leading to flooding) over SA in particular".

Appendix C includes SA rain radar screen shots from the BOM.

Wind speeds (average) were forecast in the range of 50–75 km/h, while wind speeds (gusts) were forecast in the range of 90–140 km/h.

Actual BOM weather data confirms wind speeds within the lower range of these forecasts.[23] The BOM confirmed that Yunta, approximately 276 km north of Adelaide, recorded (worst case) maximum wind speeds of 113 km/h at 1820 hrs on 28 September .[24] Other recorded maximum wind speed data[25], closer to the time of the Black System, indicates values around 100 km/h.[26] Appendix E.1 shows a summary of forecast and worst case actual data.

A recent report published by the BOM[27] provides more details of the tornadoes that are likely to have caused the observed damage to the transmission lines. The BOM indicated wind speeds in localised areas exceeded the forecast of 140 km/h (gusts) and were estimated to have been at the high end of the F2 range of 190–260 km/h. Tornado events were not forecast on this occasion.

As described in Section 2.1, AEMO's risk assessment was made at 0830 hrs based on forecasts of maximum wind speeds of 120 km/h. Updated weather forecasts issued by the BOM from 1257 hrs[28], after this assessment had been made, indicated forecast wind speeds up to 140 km/h (gusts).[29] AEMO did not review its 0830 hrs decision in light of these updated forecasts.

AEMO's post-event analysis of the weather data concludes that, based on existing practices, AEMO would not have changed its actions if it had reviewed the increase in forecast wind speeds reported from 1257 hrs.

[23] Information provided to AEMO indicates that damaged transmission lines were subjected to actual wind speeds that were much higher than forecast. Refer Section 5, Impact on Power Transmission Network Last, page 39, BOM report, *Severe thunderstorm and tornado outbreak South Australia 28 September 2016*, available at: http://www.bom.gov.au/announcements/sevwx/.

[24] Last paragraph page 21, BOM report.

[25] This refers only to general maximum wind speeds and does not include the localised extreme wind speeds due to tornadoes.

[26] Refer Appendix 0 for actual wind speed data for Snowtown, Port Pirie, Port Augusta, and Clare.

[27] Refer Section 4 Tornado Damage Assessment, page 22, BOM report.

[28] Refer Appendix E.1 Forecast Weather vs Actual, Table 20.

[29] BOM report 2016.

3. EVENTS RESULTING IN BLACK SYSTEM

3.1 Sequence of events

3.1.1 Event summary

Immediately prior to the event, Supervisory Control and Data Acquisition (SCADA) data showed that the 1,826 MW of electricity demand of SA's 850,000 electricity customers was being collectively supplied by:

- 883 MW of SA wind generation.[30]
- 330 MW of SA gas generation.
- 613 MW of electricity imports via the two interconnections with Victoria.

The total amount of domestic solar photovoltaic (PV) was estimated to be approximately 50 MW.

Extreme weather conditions resulted in five system faults on the SA transmission system in the 87 seconds between 16:16:46 and 16:18:13, with three transmission lines ultimately brought down.[31]

In response to these faults[32], and the resulting six voltage disturbances[33], there was a sustained reduction of 456 MW[34] of wind generation to the north of Adelaide. Analysis of high speed monitoring data has shown a further 42 MW of transient wind power reduction. This transient response is the normal expected response of wind farms riding through the voltage disturbances.

Increased flows on the Heywood Interconnector counteracted this loss of local generation by increasing flows from Victoria to SA. More detail on this is in Section 3.3.1.

This reduction in generation and immediate compensating increase of imports on the Heywood Interconnector resulted in the activation of Heywood Interconnector's automatic loss of synchronism protection mechanism at South East Substation (SESS), leading to the 'tripping' (disconnection) of both of the transmission circuits of the Heywood Interconnector. As a result, approximately 900 MW of supply from Victoria over the Heywood Interconnector was immediately lost, and the remaining generation in SA was unable to meet the SA demand.

This sudden and large deficit of supply caused the system frequency to collapse more quickly than the SA Under-Frequency Load Shedding (UFLS) scheme was able to act. Without any significant load shedding, the large mismatch between the remaining generation and connected load led to the system frequency collapse, and consequent Black System in SA.

Chapter 3 of this report examines the system faults and voltage disturbances in the period immediately prior to the Black System and the system response during these disturbances.

3.1.2 Measured voltages

Using high speed voltage records provided by ElectraNet, AEMO has reviewed the voltage disturbance caused by each of the faults on the transmission network. AEMO has concluded the voltage disturbances were as would be expected for the type of powerline faults that occurred. Figure 3 shows the approximate location of the faults on the SA transmission network in relation to the major substations in the area.

[30] High speed monitoring data showed 850 MW.

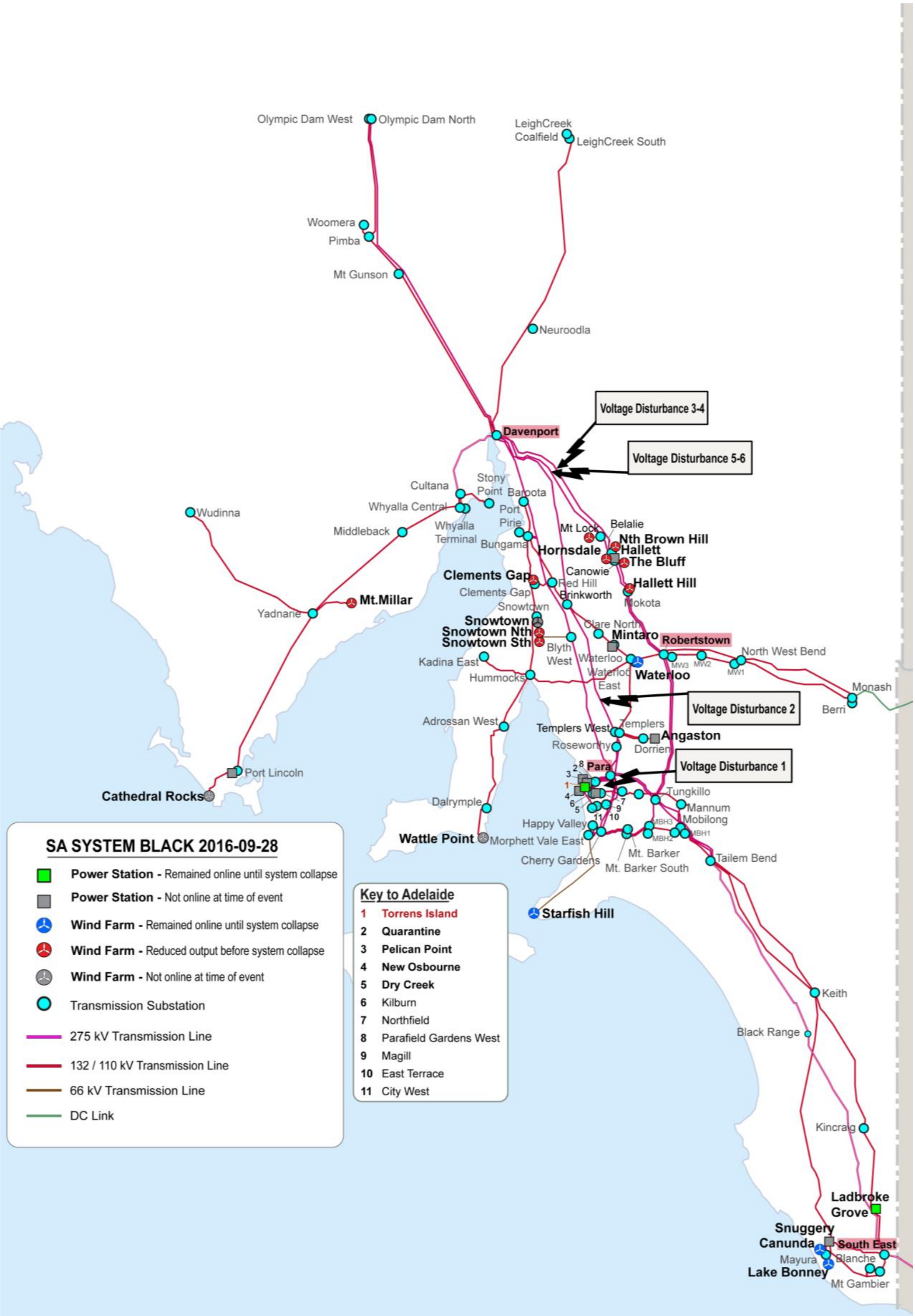
[31] From the BOM report published on 14 November 2016, AEMO concurs that the root cause of the five electrical faults occurred before the Black System was tornado conditions.

[32] In a power system, a "fault" is a condition that causes failure of the equipment in the circuit to deliver energy as intended. In this context, it is mainly the flow of current from a high voltage conductor to earth through an arc resulting from a lightning strike or direct contact caused by a fallen tower.

[33] The difference between the number of faults and the number of voltage disturbances was due to the fact that, for one fault, there was an unsuccessful auto-reclose attempt, resulting in two voltages disturbances due to the one fault.

[34] The *Preliminary Report – Black System Event in South Australia on 28 September 2016* advised 315 MW of wind generation disconnected, based on data available at that time.

Figure 3 Map of SA transmission system showing location of faults and major terminal stations



Five transmission line faults, resulting in six voltage disturbances on the network, caused sustained loss of power from multiple generating systems. This, in turn, initiated a sequence of events that ultimately led to the SA region Black System. Table 6 provides more detail on each transmission line fault.

Table 6 Transmission line faults

Fault number	Time	Details
1	16:16:46	Fault on Northfield–Harrow 66 kV feeder in the Adelaide metropolitan area. Trip and successful auto-reclose. Voltage dipped to 85% at Davenport.
2	16:17:33	Two phase to ground fault on the Brinkworth – Templers West 275 kV transmission line. No reclose attempt was made as the fault was two phase to ground whereas SA 275 kV transmission system uses single phase auto-reclosing (SPAR) only. Voltage dropped to 60% at Davenport.
3	16:17:59	Single phase to ground fault on the Davenport – Belalie 275 kV transmission line. Faulted phase successfully auto-reclosed. Voltage dropped to 40% at Davenport.
4	16:18:08	Single phase to ground fault on the Davenport – Belalie 275 kV transmission line. No auto-reclose attempted as fault was within 30 seconds of the previous fault. Line opened on all three phases and remained out of service. Voltage dropped to 40% at Davenport.
5	16:18:13	Single phase to ground fault on the Davenport – Mt Lock 275 kV transmission line. Voltage dropped to 40% at Davenport.
	16:18:14	Single phase to ground fault on the Davenport – Mt Lock 275 kV transmission line due to unsuccessful auto-reclose. Fault still on line. Line opened on all three phases and remained out of service. Voltage dropped to 40% at Davenport.

AEMO has examined the impact of these faults, as seen at Davenport, Robertstown, Para, and South East Terminal Stations, using data from high speed monitors located at these points. This data sample spans the whole SA transmission network except the Eyre Peninsula and the line to Olympic Dam.

AEMO's analysis has confirmed the same six voltage dips were experienced at the above locations between 16:16:46 and 16:18:14, corresponding to the faults on the network. The observed disturbances are smaller in magnitude further from the fault location, as would be expected. Voltages near Mount Gambier experienced the lowest deviations from their pre-event value.

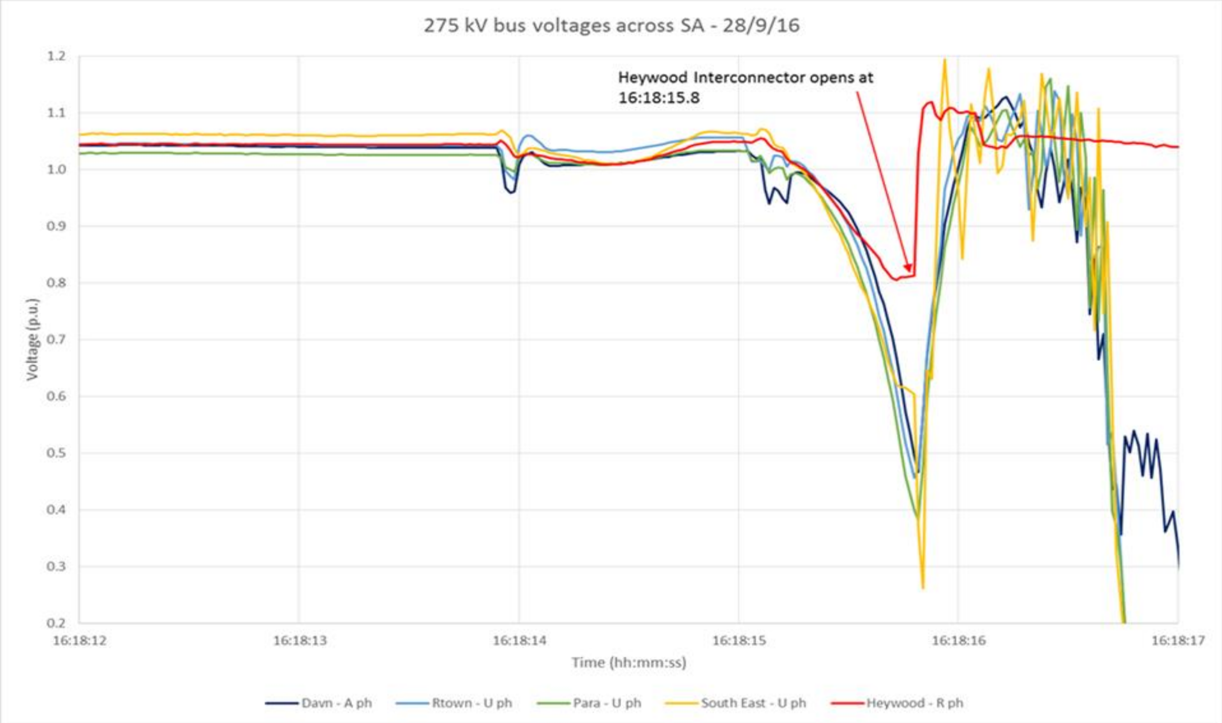
The voltage levels measured at each of these locations over the period of the SA region Black System are illustrated in Appendix G (Figure 40 to Figure 43).

Figure 4 shows voltages measured at a number of key 275 kV points across the SA networks, as well as the 275 kV voltage measured at Heywood in Victoria, for the period immediately before loss of the Heywood Interconnector.

The graph shows a rapid decline in voltages across the SA network following final loss of the Davenport – Mt Lock 275 kV line. This initial rapid decline in voltages was caused by sustained power reduction of wind generation accumulating to 456 MW just after 16:18:15 (see Section 3.2.1).

After the Heywood Interconnector opened at 16:18:15.8, the voltage levels recovered. In fact, there were over voltage conditions until the collapse of the electrical island within SA.

Figure 4 275 kV voltage decline across SA prior to separation



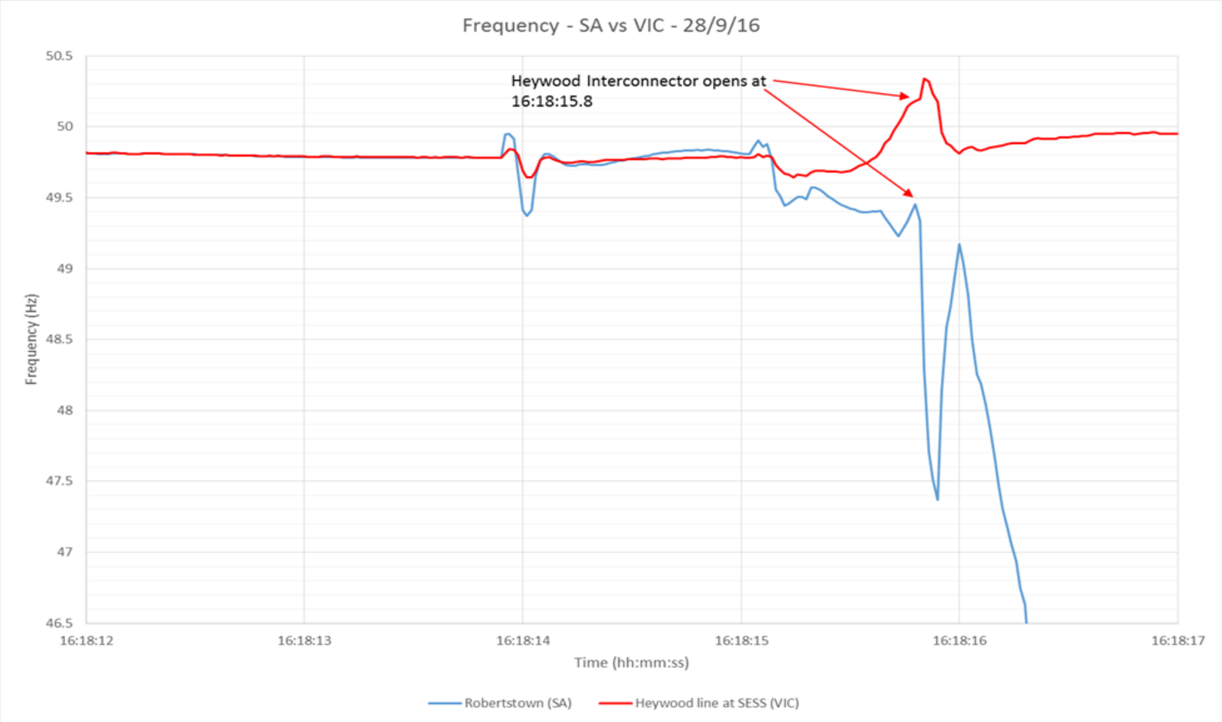
These six voltage disturbances resulted in depression of the generating systems' connection point voltage for all on-line wind farms north of Adelaide. The impact of these voltage disturbances on fault ride-through response of all on-line wind farms in SA is discussed in Section 3.2.

3.1.3 Measured frequencies

Figure 5 shows frequency measured at Robertstown in SA, and at Heywood in Victoria, in the period immediately before loss of the Heywood interconnection. Note that the Heywood frequency is measured at SESS, from the Heywood Terminal Station (HYTS) line voltage transformers. These voltage transformers are on the line side of the circuit breakers (CBs) on the HYTS to SESS lines which were opened by the loss of synchronism protection at the time of separation, and thus were connected to Victoria post-separation.

It shows a separation in the measured frequency between the two areas in the period immediately prior to loss of the Heywood Interconnector. Again, this is consistent with a loss of synchronism between the SA power system and the remainder of the NEM.

Figure 5 SA frequency compared to Victoria during event



SA's UFLS scheme is designed to quickly rebalance supply and demand, following any separation from Victoria which leaves SA short of supply.

It triggers in stages, and starts when frequency falls below 49 hertz (Hz). In each stage of load shedding, as soon as frequency drops below a certain value, a pre-determined percentage of the load allocated for load shedding will be disconnected after a pre-determined time delay. It is designed such that all load available to the UFLS scheme will be shed by the time frequency declines to 47.5 Hz. Clause 4.3.5 of the NER requires that at least 60% of customer demand for connection points over 10 MW is available for UFLS.

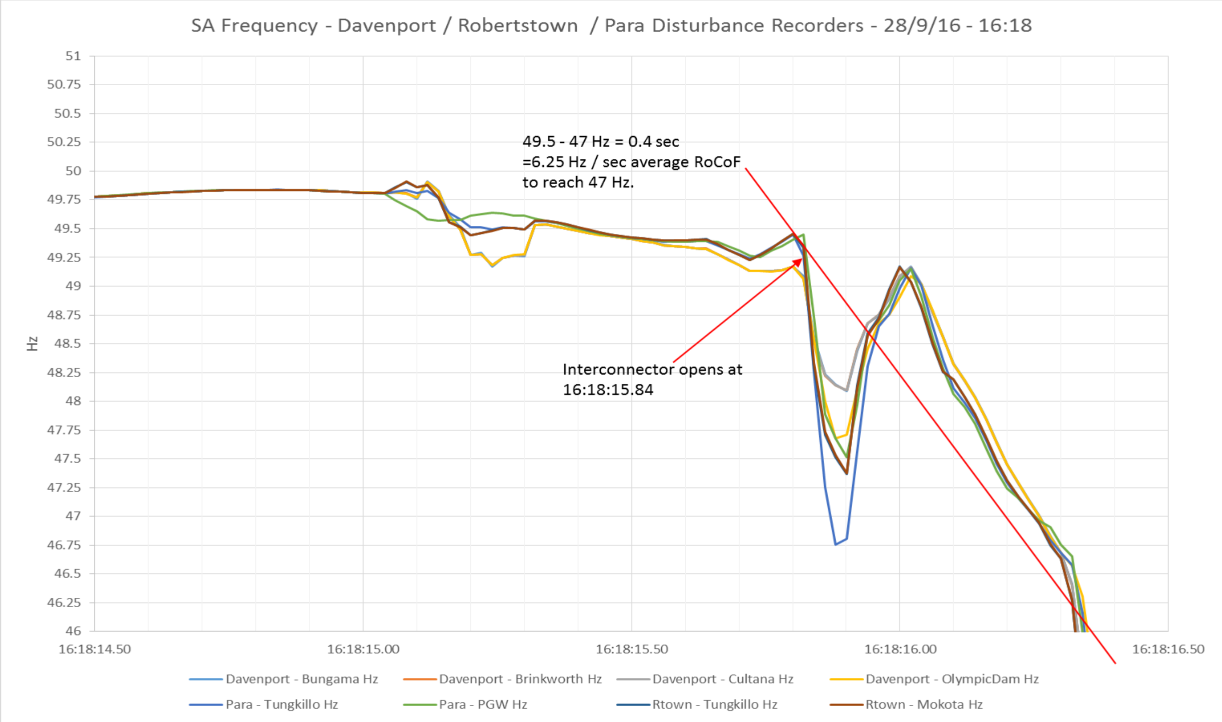
On 28 September 2016, the UFLS scheme did not trigger prior to the loss of the Heywood Interconnector, as the frequency remained above the 49 Hz trigger level.

Upon loss of the Heywood Interconnector, Figure 6 indicates that the rapid Rate of Change of Frequency (RoCoF) experienced in SA was too great for the UFLS to stop the fall in frequency. Effectively, the time taken for the frequency to suddenly drop from 49 Hz to below 47 Hz was too fast considering various time delays involved in operation of this scheme.

All UFLS load blocks in SA have a total measurement and operating delay varying between 150 and 250 ms. This delay varies depending on the type of relay used, the number of CBs that need to be disconnected, and the voltage level to which the CB is connected (lower voltage CBs have longer opening time).

Following the sustained reduction of 456 MW of wind generation, frequency started to decline until 16:18:15.8 where the system separation occurred. At this point, a frequency nadir between 47 Hz and 48 Hz was observed in most SA nodes. Immediately after the separation, a momentary frequency rebound reaching 49.2 Hz was experienced.

Figure 6 Frequency and ROCOF in various SA nodes immediately before the system separation



It is not clear whether these frequency measurements are a true reflection of power system frequency, or a transient frequency measurement or calculation issue, given the large and almost step changes in voltage phase angles in SA following separation (see Figure 13). These sudden angle changes, along with rapid changes in load due to operation of the UFLS scheme, may result in short-term inaccuracies in frequency measurements.

The key reason for the frequency collapse was that, in the absence of any substantial load shedding, the remaining synchronous generators and wind farms were unable to maintain the islanded system frequency. The frequency in various SA nodes therefore fell rapidly following loss of the Heywood Interconnector, dropping below 47 Hz in most parts of the SA island. This is the lower bound of the extreme frequency excursion tolerance limits nominated in the frequency operating standards determined by the Reliability Panel. Generators are not required to operate outside the extreme frequency excursion tolerance limits.

In summary, there was a rapid fall in frequency in the SA region following separation. The rate of change of frequency was too great for the UFLS scheme to operate effectively. The frequency fell below 47 Hz and the remaining generation in SA tripped as would be expected. Even if the UFLS scheme had operated quickly enough, resulting in 60% of SA load being shed on time, the remaining load of approximately 800 MW was too great for the remaining generation[35] to maintain the islanded system frequency.

[35] The remaining generation comprised three TIPS B units, two Ladbroke Grove units, Canunda, Lake Bonney and Waterloo Wind Farms, and import from Murraylink. Given large oscillations in active power responses of the generating systems it is not practical to quote fixed MW figures for these generating systems after system separation. Additionally, reduced system strength caused by system separation raises a question as to whether or not these wind farms would have remained connected (see Section 3.5.2 for details on the definition of short circuit ratio (SCR) and the need for the available fault level in the system to exceed the minimum SCR withstand capability of wind turbines, as confirmed by each original equipment manufacturer to AEMO). Lastly, it is noted that none of the five synchronous generating units were participating in the FCAS market, hence they were unable to immediately rebalance the supply to meet the connected load if a stable island had been formed.

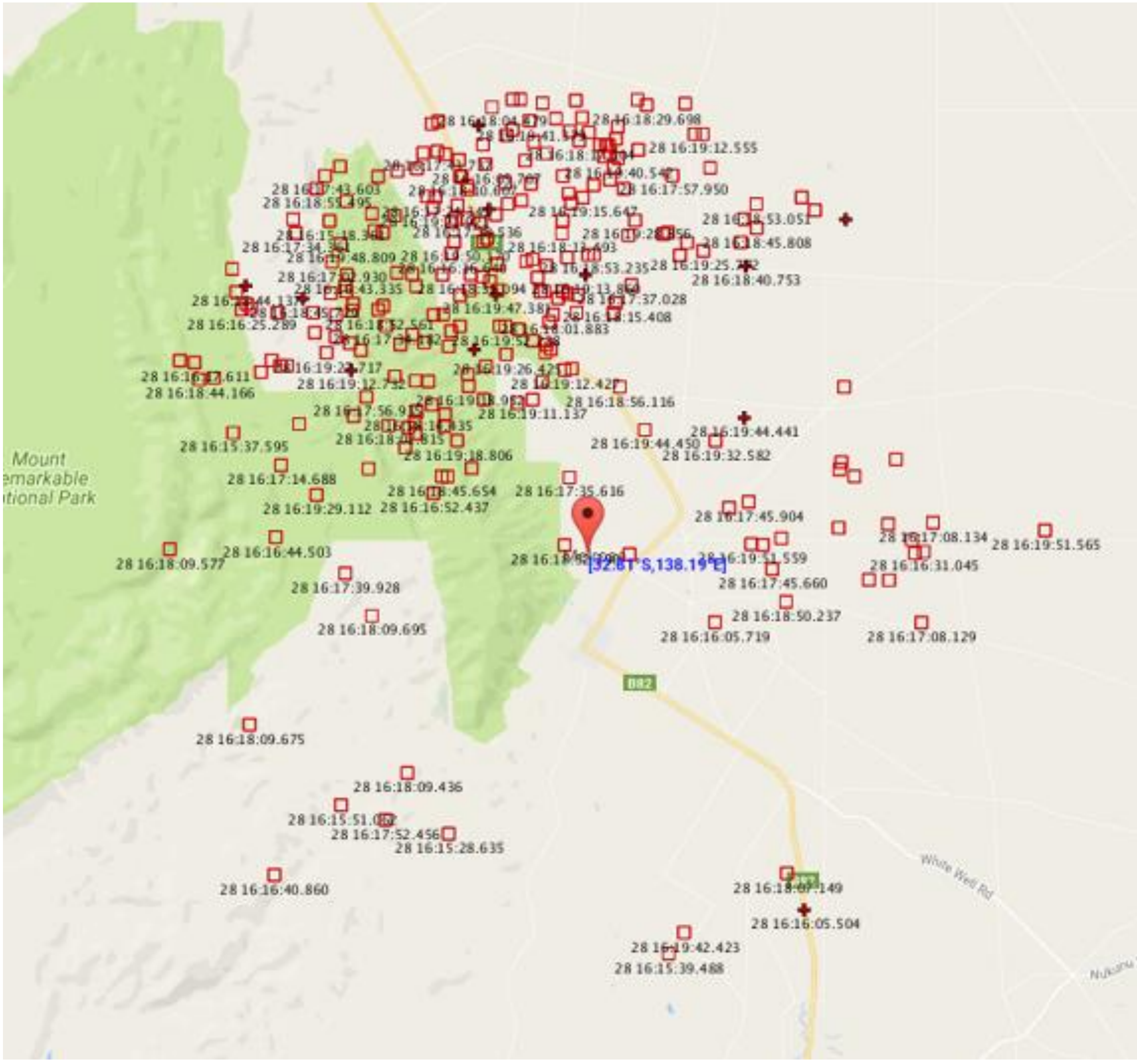
3.1.4 Cause of electrical faults

Lightning strikes

Close inspection of lightning strike data for various locations in the mid-north and northern parts of SA during the five electrical faults indicates low levels of lightning strikes for most locations except Melrose.

As Figure 7 shows, the Melrose region was subjected to 263 lightning strikes in five minutes. However, close inspection of lightning strike data indicates that all lightning strikes within a few hundred milliseconds of the known system faults (see Table 6) are CC (cloud-to-cloud) type rather than CG (cloud-to-ground). Traditionally, only CG flashes are considered when analysing the cause of electrical faults, because CC discharges do not involve a path to the ground and cannot cause an electrical fault between phase(s) and the ground.

Figure 7 Lightning stike map for Melrose area in the five minutes prior to the Black System



Tornadoes

Tornadoes can come in many shapes, but are typically in the form of visible condensation funnel, with the narrow end touching the earth. Often, a cloud of debris caused by its destructive force encircles the lower portion of the funnel.

BOM's post-event report[36] confirms the presence of tornadoes near the following transmission circuits between 1605 hrs and 1635 hrs on 28 September 2016:

- Brinkworth – Templars West 275 kV line.
- Davenport–Belalie 275 kV line.
- Davenport – Mt Lock 275 kV line.

This information corroborates the conclusion that tornadoes were the cause of the five electrical faults that occurred before the system separation, due to either the associated high rotating winds or clouds of debris causing damage to towers or conductors to clash.

The BOM, however, does not suggest a tornado as the cause of the Davenport–Brinkworth 275 kV line outage that occurred after the Black System. It suggests that those towers were impacted by a severe downdraft within minutes of the Black System.

The wind speeds involved, as estimated in the BOM report, were well in excess of the design rating of these transmission lines (refer Appendix V).[37]

General high wind speeds

Data from the BOM indicates a peak mean wind speed of 57 km/h with gusts reaching 70 km/h. This would have been insufficient to cause major concerns on transmission network. In its report, however, the BOM indicates wind strengths ranging from 190 to 260 km/h in localised areas and evidence of tornadoes.

Conclusion

The cause of transmission network faults immediately prior to the Black System can be attributed to localised tornadoes.

3.2 SA Generator performance

3.2.1 Wind farms

Wind turbine fault ride-through capability

Wind turbines are designed so that when a low voltage is detected at their terminals, the normal steady-state control is suspended and a sequence of actions is initiated by the turbine control systems, referred to as fault 'ride-through' mode. The purpose is for the wind turbine to remain connected to the grid and provide support to the voltage recovery at the point of connection.

Wind turbine control systems are set to provide a fault ride-through response when voltage dips to below 80% to 90% of normal voltage, as seen at the turbines' voltage terminals. This applies to all wind turbines installed in SA.[38]

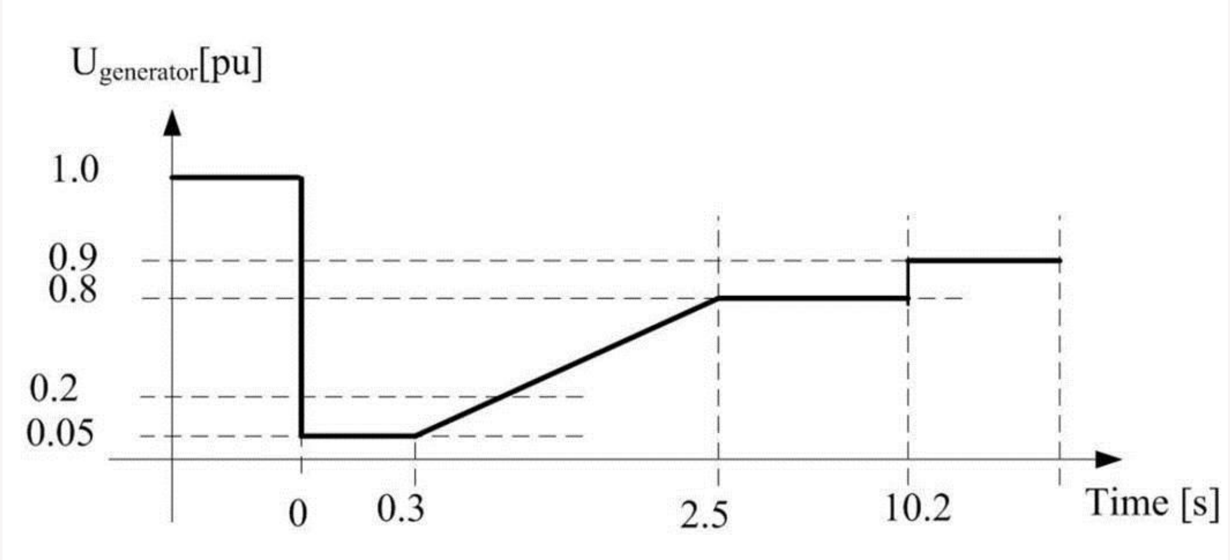
In response to exactly the same voltage dips, wind turbines with a higher low-voltage ride-through (LVRT) activation threshold, such as 90%, activate fault ride-through mode more often than wind turbines with a lower LVRT activation threshold. For example, for voltage dips of 15%, 20%, and 25%, a wind turbine with LVRT activation threshold of 90% would activate fault ride-through mode three times, while another wind turbine with LVRT activation threshold of 80% would activate fault ride-through mode twice only.

The size of the voltage dips observed by SA wind turbines on-line at the time of the event was sufficient for ten of the thirteen on-line wind farms to activate their fault ride-through mode. Depending on the wind farm, this mode of turbine operation was activated between three and six times.

[36] Severe thunderstorm and tornado outbreak South Australia 28 September 2016, available at: http://www.bom.gov.au/announcements/sevwx/.
[37] This new advice supersedes previous advice from ElectraNet on the design ratings, which was referenced in the Update Report.
[38] Similar fault ride-through design applies to most other power electronic technologies, such as solar inverters, High Voltage Direct Current (HVDC) links, Static Compensators (STATCOMs), and other power electronic devices that interact with the power system. More traditional power system assets, such as synchronous generators, achieve ride-through based on their physical properties rather than power electronics with software controls.

Figure 8 shows an example of LVRT withstand capability of a commercial wind turbine installed in SA. This wind turbine will ride through faults when the combination of residual voltage and fault duration is above the black line. For example, this turbine can ride through a fault with a residual voltage of 5% for 300 ms. If the fault lasts for longer than 300 ms at 5% residual voltage, the turbine will disconnect. Equally, if the fault has a residual voltage less than 5% at any time, the turbine will disconnect. Both of these disconnection examples occur as the time-voltage profile of the fault is not within the turbine withstand capability, that is, not above the black line.

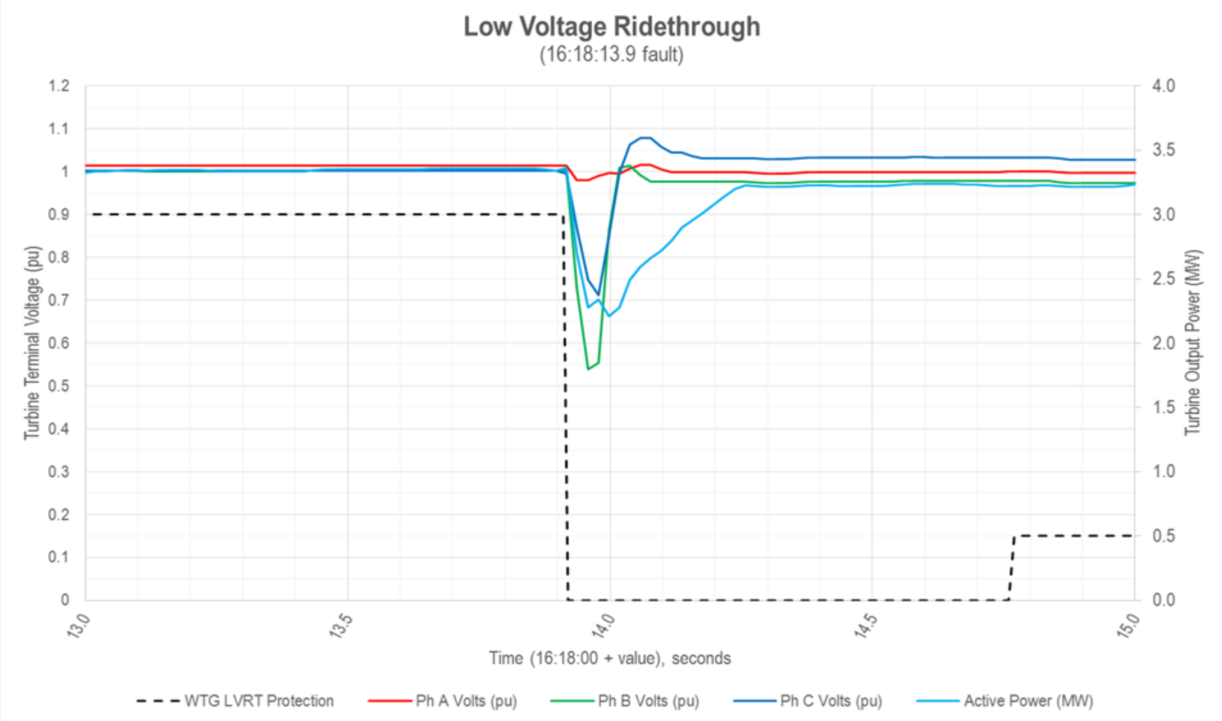
Figure 8 Example of low voltage ride-through withstand capability curve at the wind turbine terminals



Source: Vestas Wind Systems A/S. *Advanced Grid Option 2, Vestas VCS turbines*, 2011.

Figure 9 shows an example of a wind turbine installed in SA, comparing three-phase voltages measured at the wind turbine terminals for the fault that occurred at 16:18:13.9 against the LVRT withstand capability of this type of wind turbine. This figure illustrates that the wind turbine recovered its active power output shortly after the fault clearance. This is because the fault was within the LVRT withstand capability of this particular wind turbine type.

Figure 9 Voltage response of an example wind turbine against its LVRT withstand capability



Similar trends can be observed on all other wind turbines, whereby the voltage dips were within their LVRT withstand capability.

All wind turbines successfully rode through faults until the pre-set protection limit applied to most on-line wind turbines was reached or exceeded. This will be further discussed in this sub-section.

Relation to connection studies and commissioning tests

The following applies when a Generator seeks connection to the grid.

Model assessment and due diligence studies

Following negotiation of suitable performance standards between the connection applicant and the connecting NSP, with AEMO's input where required by the NER, AEMO conducts a due diligence review of the capability of a generating system to meet its performance standards.

To make this assessment, AEMO uses power system simulation software, together with computer models of the generating system provided by the applicant. The requirements for generating system models are specified in AEMO's Generating System Model Guidelines.[39]

In this assessment, AEMO reviews any technical studies presented by the connection applicant and/or the connecting NSP, and conducts its own studies.

AEMO will generally select a subset of scenarios to consider, covering the extremes of power system loading and generation dispatch and fault severity. The faults studied are typically those that will have the greatest impact (lowest system voltage at connection point) and the longest clearing time. Historically, the greatest issue with fault ride-through capability has related to transient stability, which is highly dependent on these factors.

[39] Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Network-connections/-/media/B468B9355D4249C2A0BF55C44971B08C.ashx.

Commissioning and compliance testing

A Generator seeking connection is responsible for demonstrating the compliance of each of its generating systems with its performance standards and for demonstrating the accuracy of models via R2[40] model validation, as specified in clause S5.5.2 of the NER.

As part of the initial commissioning and compliance regime, AEMO will review the Generator's commissioning test results as well as model validation results. Generating system models are only accepted as R2 (registered) data after the Generator has demonstrated the model satisfies the accuracy requirements of the Generating System Model Guidelines.

For some criteria defined in the generator performance standards, direct testing is not practicable. Testing of fault ride-through requirements involves the application of a network fault. While this method has been used in rare circumstances, it is not typical, because it places network security, reliability, and plant integrity at risk.

The primary means of testing compliance against fault ride-through requirements set out in NER S5.2.5.5 has been through long-term event monitoring. Measured responses captured through long-term monitoring are then compared against simulated responses, to:

- Ensure the veracity of results obtained from simulation models.
- Confirm that associated generator performance standards can be met or exceeded in practice.
- Derive validated R2 models.

Like other types of generating systems, wind farms demonstrate compliance with relevant generator performance standards requirements through their performance during network faults over time.[41] Non-compliance may be identified by Generators, AEMO or network service providers, and can be reported and resolved via the performance standards compliance process set out in clauses 4.15(f), 4.15(g) and 5.8.5(d) of the NER.

The end-to-end generator connection assessment described above highlights the process applied by AEMO and relevant NSPs to ensure fault ride-through capability of the generating system. Salient activities conducted in this process include:

- Confirmation of the compatibility and authentication of simulation models submitted to AEMO.
- Due diligence studies to confirm relevant clauses in generator performance standard as proposed by the Generator.
- Commissioning tests and long-term monitoring to demonstrate the ability to meet relevant clauses on the actual installed plant and validate the simulation models.

AEMO's awareness of ride-through capability for multiple successive faults

The event has revealed that many wind farms in the NEM have a protection feature that takes action if the number of ride-through events in a specific period exceeds a pre-set limit. Each wind turbine then either disconnects from the network, stops operating (remains connected with zero output), or reduces its output.

AEMO was unaware of this protection feature before the Black System event of 28 September 2016 in SA, for the following reasons:

- This protection feature is not represented in the simulation models submitted to AEMO for any of the affected wind farms. AEMO is also unaware of this feature in any other wind turbine simulation models it has received. Accordingly, simulations of wind farm performance using the wind farm models currently available to AEMO would not display disconnection or offloading in response to a large number of faults in quick succession.

[40] R2 is registered data on generating plant which is obtained from on-system testing after the connection of the generator to the power system.

[41] A common practice applied in Europe for assessing fault ride-through capability of actual wind turbines is container tests, which subject a single wind turbine in isolation to a number of defined fault scenarios as required for certification of wind turbine models in certain countries. Some of the factors relating to actual network faults, such as fault impedance, system strength, and impact of nearby power system equipment, cannot be always adequately accounted for. In addition, AEMO understands that these types of tests have not been previously used for application of multiple faults in quick succession, like six voltage disturbances within two minutes, and would need modifications to the standard set-up.

- Compliance with respect to fault ride-through capability is generally assessed based on recorded network fault event analysis. No previous examples of repeated fault ride-through issues with wind farms have been reported to AEMO.[42] Additionally, AEMO is not aware of any reported instances of this phenomenon internationally.

Response of on-line wind farms

Summary

The size of the voltage dips observed by SA wind turbines on-line at the time of the event was sufficient for ten of the thirteen wind farms on-line to activate their fault ride-through function. Depending on the wind farm, this mode of turbine operation was activated between three and six times, as shown in Table 7.

Of the 13 wind farms on-line prior to the event, four remained in service: Canunda, Lake Bonney 1, Lake Bonney 2 & 3[43], and Waterloo. Of these, only one (Waterloo) initiated ride-through mode multiple times, but it remained in service because it was set to a limit of more than six ride-through events.

The size of the voltage dips for wind farms connected to the south-east part of SA, such as Lake Bonney and Canunda wind farms, was not as large as the voltage dips observed at Davenport. Wind turbines in the south-east initiated fault ride-through mode either once, at around 16:18:15, or not at all.

Table 7 SA wind farm responses to six voltage disturbances between 16:17:33 and 16:18:15 on 28 September 2016

Wind Farm	Pre-set limit allowing maximum number of successful ride-through events in 120 seconds	Number of times wind turbines activated ride-through mode within 120 seconds	Last state of wind turbines prior to system collapse	Output pre-event at 16:18:08 [MW]	Output just prior to state separation at 16:18:15.4 [MW]
Canunda	10	1	Operational	45.6	44.2
Lake Bonney 1	5–10	0	Operational	77.7	79.1
Lake Bonney 2	10	0	Operational	59.6	54.3
Lake Bonney 3	10	0	Operational	112.5	102.0
Waterloo	10	6	Operational	97.2	71.2
			Transient MW Reduction		**42.0**
Clements Gap	2	3	Disconnected	14.6	-0.5
Hallett	2	3	Most turbines disconnected	38.5	-0.6
Hallett Hill	2	3	Most turbines disconnected	43.4	18.6
Mt Millar	Not applicable	5	Zero power mode	66.6	1.9

42 AEMO is made aware of non-compliances with performance standards for fault ride-through by a number of means including:
- Long-term monitoring and network fault event data provided by wind farms to:
  - Demonstrate wind farm compliance with respect to pertinent clauses in their generator performance standards as required in their performance monitoring plans.
  - Validate wind farm models (R2).
- Notice of non-compliances which need to be submitted by wind farm owners as soon as it is identified as set out in clauses 4.15 (f), 4.15 (g) and 5.8.5 (d) of the NER.

AEMO's investigation of historical events resulting in loss of multiple circuits and the extent to which they resulted in multiple successive faults on any wind farms.

43 Lake Bonney wind farms 2 and 3 are counted as a single wind farm since they connect to the transmission network at a single point.

Wind Farm	Pre-set limit allowing maximum number of successful ride-through events in 120 seconds	Number of times wind turbines activated ride-through mode within 120 seconds	Last state of wind turbines prior to system collapse	Output pre-event at 16:18:08 [MW]	Output just prior to state separation at 16:18:15.4 [MW]
North Brown Hill	2	3	Most turbines disconnected	87.0	11.0
Hornsdale	5	6	Stopped Operation	83.6	-1.1
Snowtown North	5	6	Stopped Operation	65.9	-0.8
Snowtown South	5	6	Stopped Operation	41.3	-1.2
The Bluff	2	3	Most turbines disconnected	42.6	-0.3
			Sustained MW Reduction		**456.3**
Total MW output				**876.1**	**377.7**
Total MW loss					**498.4**

Note that the data used in Table 7 is from high speed monitoring devices. It has been provided to AEMO by Registered Participants. This is the most accurate information of the state of the system available during the final seconds lead-up to the Black System. Differences between SCADA and high speed data are evident as energy flow in the power system was changing faster than SCADA can capture, and data was not necessarily recorded at the same instant of time.

Cause of wind generation reduction

AEMO has been working with each wind farm operator to determine the causes of this reduction.

To illustrate the output reductions, the wind farms have been grouped together as shown in Table 8.

Table 8 SA wind farms on-line in SA on 28 September 2016

Wind farm – 'Grouping'	Wind farms
Group A	Hallett, Hallett Hill, The Bluff, North Brown Hill, Clements Gap
Group B	Hornsdale, Snowtown North and South (collectively referred to as Snowtown II Wind Farm)
Group C	Mt. Millar
Group D	Lake Bonney 1, 2, 3, Canunda, Waterloo

From information made available to date by wind farm operators and turbine manufacturers, AEMO has concluded the following.

Group A and B

Nine wind farms exhibited sustained power reduction during the six voltage disturbances on the transmission system, out of which eight wind farms are categorised as Group A and B in this report. Group A and B wind turbines have a protection system that takes action if the number of ride-through events in a specific period exceeds a pre-set limit.

- If the pre-set limit was exceeded in the event, each wind turbine either disconnected from the network, stopped operating (remained connected with zero output), or reduced its output.
- The pre-set limit varied from wind farm to wind farm, and the six voltage disturbances exceeded this limit in some cases.
- This protection system caused eight wind farms to reduce output when the number of ride-through events caused by voltage disturbances exceeded the pre-set limits.

Group C

The operating philosophy of Group C wind turbines differs from all other wind turbines such that when a system disturbance occurs which causes the AC voltage at the wind turbine terminals to fall below 0.8 per unit (pu), the power electronic converter used in the wind turbine is blocked about 40 ms later. The current supply to the grid is therefore forced to zero (i.e. P = Q = 0) referred to as the “zero power mode” of operation.

The process of unblocking the power electronics and restoring power output from the wind turbine commences if the generating unit’s low voltage terminal voltage recovers to a pre-set level of 0.8 pu. Current ramping to the pre-disturbance value commences at an approximately fixed rate about 100 ms after the voltage recovers. The ramp rate to increase the current from zero to its rated value is 8 MW/s. During and immediately following the clearance of the fault, no current is supplied by the wind turbine.

AEMO therefore concludes that the sustained power reduction by Group C wind turbines was caused by zero power mode fault ride-through response and slow active power recovery of 8 MW/s. However, it must be recognised the single line connecting this wind farm to the grid was damaged in the storm.

Group D

In addition to the 456 MW sustained power reduction associated with the response of nine wind farms to six successive voltage disturbances, a further reduction of 42 MW of wind power reduction was observed at 16:18:15.4 (the onset of rapid voltage decline). This was caused by the natural response of those remaining wind farms that activated their fault ride-through mode.

While these wind farms successfully rode through the faults, they did not recover to the pre-disturbance output power level immediately and took several hundred milliseconds to recover. This resulted in a transient loss of 42 MW of wind generation in SA which caused a further increase in Heywood Interconnector flow. All wind turbines that exhibited this behaviour remained connected and operational until the SA power system was fully lost at 16:18:16.

The power reduction across the wind farms is illustrated in Figure 10 below.

Figure 10 Total wind farm output – Sustained vs transient power reduction, 28 September 2016

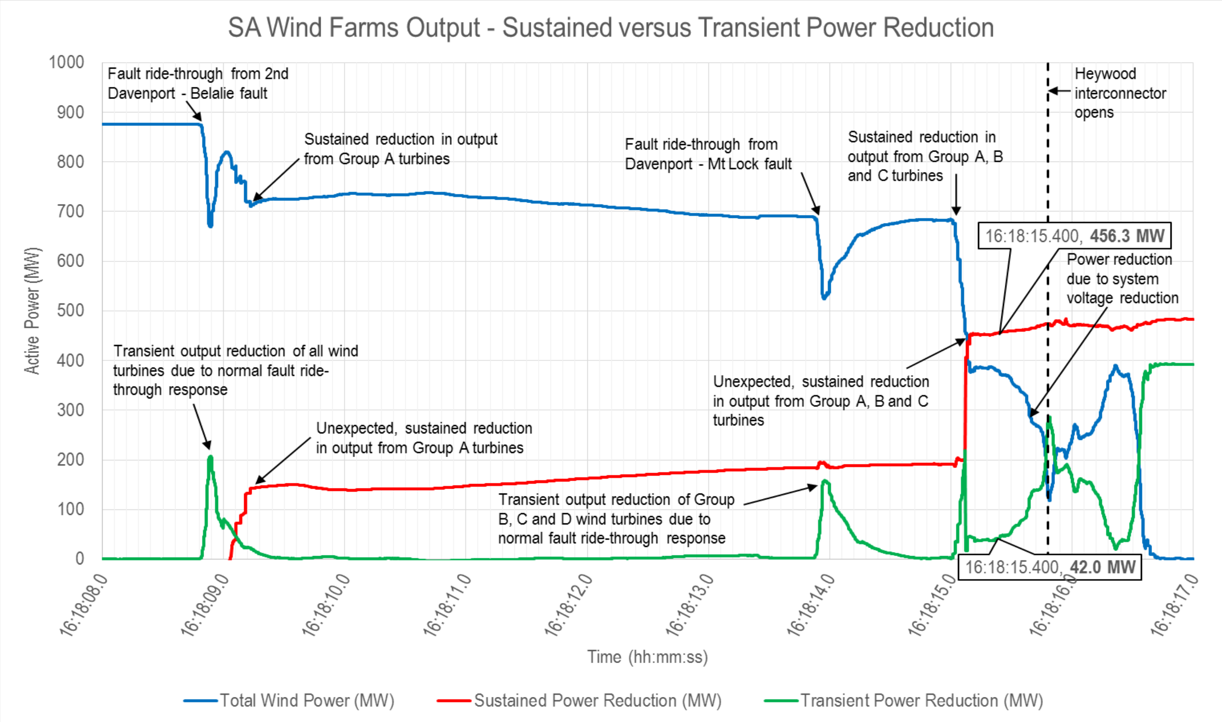
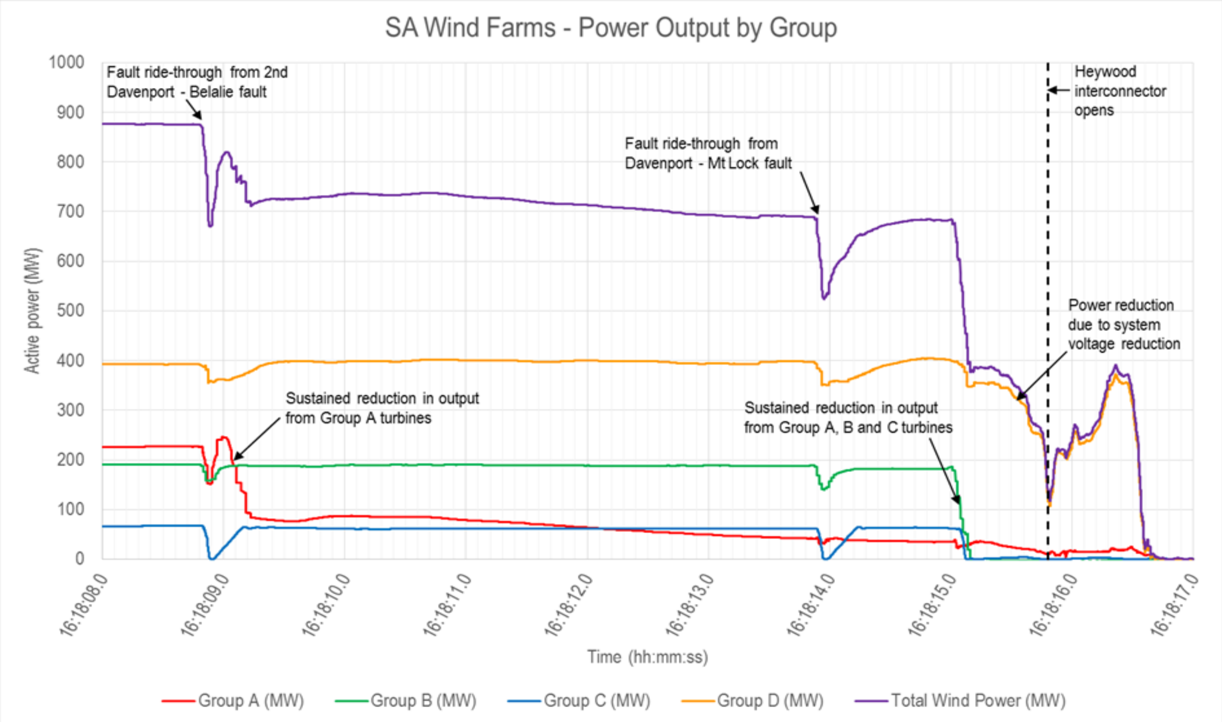


Figure 11 below illustrates the power reduction of wind farms, based on the grouping in Table 8. It also highlights the following observations (noting the SA power system had experienced three voltage disturbances just prior to the time shown on Figure 11):

- **16:18:08.8:** Fast reduction in power by Group A wind turbines due to the occurrence of a third successive voltage disturbance within two minutes, as seen by most on-line wind turbines. Most wind turbines successfully rode through the third voltage disturbance, then either reduced output or disconnected due to the activation of repetitive LVRT protection.
- **16:18:15.1**: Fast reduction in power by Group B wind turbines due to the occurrence of six successive voltage disturbances within two minutes. This resulted in activation of protection to stop the turbines. At the same time, all on-line Group C wind turbines dropped their active power to zero due to zero power mode fault ride-through response.
- **16:18:09.2 to 16:18.15.4**: Slow reduction in power by remaining Group A wind turbines from a total of 80 MW to 40 MW just prior to the rapid voltage decline. AEMO is continuing to investigate the circumstances leading to this reduction.
- **16:18:15.1 to 16:18.15.4**: Transient reduction in power by Group D wind turbines amounting to 42 MW at 16:18:15.4 due to natural fault ride-through response of these wind turbines.
- **16:18:16:** A small number of Group A wind turbines remained connected after system separation. Close inspection of three-phase voltages across those wind turbines indicate that only two of the six voltage disturbances (those occurred at 16:17:59 and 16:18.08) were large enough to activate the LVRT mode. Those wind turbines did not exceed the pre-set limit of three which would have otherwise resulted in disconnection.

Figure 11 Wind farm power reduction based on wind turbine grouping



Response of individual wind farms

Figure 44 to Figure 56 in Appendix I.1 show the response of individual wind farms during the Black System event. These figures illustrate connection point voltages, active and reactive power between 16:18:08 and 16:18:16. Where the connection point data is missing or insufficient, measured data taken from an adjacent transmission substation is used.

The following key observations can be made:

- All faults were successfully cleared within the time settings of the appropriate primary protection systems, which ranged from 80 to 120 ms.
- Immediately prior to the event, steady-state connection point voltages were stable and within 90 to 100 % of nominal defined as continuous uninterrupted operating range in clause S5.2.5.4 of the NER.
- Voltage collapse began after clearance of the sixth voltage disturbance and sustained generation reduction of 260 MW associated with three wind farms (Groups B and C). This confirms system voltages were stable and would have remained stable if angular instability had been avoided.
- All faults seen by individual wind turbines were within their respective LVRT withstand capability (see Figure 9 as an example). All on-line wind turbines were therefore expected to maintain their continuous uninterrupted operation, and resume their active power output shortly after the fault clearance.
- Most wind farms increased their reactive power injection in response to each fault as expected. However, a number of wind farms exhibited a reduction in their reactive power injection. This will be investigated further in AEMO's final report.
- Following clearance of all faults, 456 MW of sustained power reduction by nine wind farms, and onset of global voltage instability at 16:18:15.2, a number of wind farms increased their reactive power injection to restore the respective connection point voltages. However, three wind farms reduced their reactive power injection. This was inconsistent with the expected performance, and will be investigated further in AEMO's final report.

- Of the 14 on-line wind farms, 10 utilise dynamic reactive power support plant in form of static compensators (STATCOMs). The response of these devices during the incident will be investigated further in AEMO's final report.

In summary, each individual fault was consistent with the historical network faults on the SA transmission network, which wind farms are expected to ride through. Following clearance of each fault, connection point voltage for each on-line wind farm returned to the range for which continuous uninterrupted operation is required. All on-line wind farms successfully rode through faults until a pre-set limit which allows a maximum number of successful ride-through events was reached or exceeded. This resulted in sustained power reduction by Group A and B wind farms. The system-wide voltage instability commenced after sustained power reduction of 456 MW by nine wind farms.

Impact of wind intermittency and over-speed

The most well-known characteristic of wind power, variation of output with wind strength (often termed 'intermittency'), was not a material factor in the events immediately prior to the Black System.

Other potential causes for the sustained power reduction have been subject to analysis by AEMO, including wind turbine disconnection due to excessive wind speed. Typically, wind turbines exhibit a protective behaviour whereby they shut down to protect themselves from excessive mechanical stress in high winds, typically 90 km/h or more. Approximately 20 MW of wind power was disconnected due to excessive wind in the last five minutes prior to the Black System.

This was not a material contribution to the event.

Subsequent measures taken by Generators

Based on information provided to AEMO by SA Generators and respective wind turbine manufacturers following the Black System, AEMO understands the purpose of the protection settings, with respect to the number of successive faults for which fault ride-through mode is activated, is to:

- Avoid excessive stress and fatigue on turbine mechanical drive train, tower, and so on, and
- Account for the cooling cycle and thermal capacity of dump resistors included in modern wind turbines for enhanced fault ride-through capability.

Additional factors which determine the number of successive faults that can be ridden through are the fault duration and size of voltage dip for each fault. For example, a given wind turbine may be designed to withstand 10 faults, each lasting up to 200 ms, with a maximum voltage drop of 20% each.

Generators involved have advised that these protection settings can be increased to some extent without compromising the integrity and lifetime of the electrical and mechanical components in the wind turbine. However, they have requested time to assess and reconsider all implications before confirming new settings for long-term application.

Within days of the event, AEMO permitted some of the impacted Generators to implement the proposed new settings on-site, enabling successful ride-through for a larger number of successive faults. These Generators have subsequently proposed to further amend these protection settings. One Generator has confirmed that its turbines have a similar protection function, but it was not operating at the time of the incident. This Generator has also proposed to amend its settings for this function before confirming those settings for the long term.

Table 9 indicates the current capability of SA wind turbines in relation to successive fault ride-through capability, remedial measures proposed by the affected wind turbines, and an indication of the capability of other installed wind turbines in SA. This information was provided to AEMO by SA Generators and respective wind turbine manufacturers following the Black System.

Subject to Generator Performance Standard requirements, protection settings are a question for each wind farm in consultation with their manufacturer. AEMO is continuing to consult with wind farm operators and wind turbine manufacturers to better understand the impact on the power system of their existing and revised settings.

Table 9 Protection settings implemented in SA wind turbines at the time of incident, and proposed mitigation measures

Wind turbine group	Installed capacity in SA (MW)	Able to ride-through multiple faults on 28 September 2016	Multiple ride-through capability on 28 September 2016	Actions taken for improved ride-through capability
Group A	507	No	2 within 2 minutes[a]	Proposed 4 within 2 minutes
Group B	372	No	5 within 30 minutes (also 5 within 2 minutes)	Changed to 20 within 120 minutes (also 20 within 2 minutes)
Group C	70	No	Varies depending on fault duration, dip size and rate of active and reactive power recovery following fault clearance Can ride through at least 9 faults within 30 minutes if cleared within primary protection clearance time.	Investigating the possibility of modifying fault ride-through mode from zero power mode to reactive power and voltage control mode to avoid sustained power reduction during faults
Group D	627	Yes	Up to 10 within 30 minutes • 10 for Canunda, Cathedral Rocks, Lake Bonney 2, 3 and Waterloo wind farms. • Wattle point, Lake Bonney 1, and Starfish Hill wind farms are yet to be confirmed.	No further increase has been proposed

a In this table, a setting allowing plant to ride through two successive faults but disconnect on the third fault is described as “2 within 2 minutes”.

AEMO notes that the modifications proposed on Group A wind farms would be insufficient to avoid sustained power reduction in the circumstances that occurred on 28 September 2016. This is because many of these wind turbines experienced five or six electrical faults in quick successions, and the proposed revised settings allow for successful ride-through of four voltage disturbances within two minutes. AEMO will present its analysis of the risk associated with these settings in its final report.

In addition to the impacted wind farms in SA, AEMO is currently in discussion with wind farm operators and wind turbine manufacturers in all NEM regions to understand the capability of all wind turbines currently installed in the NEM to ride through multiple successive faults.

In summary, action has been taken to improve the multiple ride-through capability of wind farms in SA and elsewhere in the NEM. Some changes to protection settings have been made, and other changes are under consideration. However risks in this area still remain and will be assessed further in AEMO’s final report.

3.2.2 Synchronous generators

A synchronous generator responds to disturbances by virtue of its physical characteristics (size, mass, rotational inertia) and by the action of its automatic voltage regulator. This provides fault ride-through capability and network voltage support. Unlike most power electronic based devices, these generators do not necessarily switch into a distinct fault ride-through mode. The primary concern for a synchronous generator during multiple, successive faults is the mechanical stresses placed on the turbine and generator.

For the voltage disturbances experienced on the SA transmission system between 1616 hrs and 1618 hrs on 28 September 2016, the data available to AEMO shows:

- All five synchronous generating units (three at Torrens Island and two at Ladbroke Grove) remained connected until 16:18:16, when the SA transmission system was disconnected from the rest of the NEM. They showed no active power reduction prior to this time.
- Operation of the five on-line synchronous generators did not contribute to this event.

Torrens Island Power Station (TIPS) B

Figures 56 to 58 in Appendix I.2 show the response of the three TIPS B units on-line during the event. AEMO makes the following key observations:

- Following clearance of the sixth voltage disturbance, the three on-line TIPS B generators increased their active power generation from ≈80 MW to ≈110 MW immediately before system separation. This demonstrates inertial contribution of these units.
- Immediately after the system separation, all three units increased their active power generation momentarily until the system collapsed. This also demonstrates inertial contribution of these units.
- None of the three TIPS B generating units was providing FCAS prior to the event. AEMO notes that the frequency in SA at no time required any FCAS response until after the loss of the Heywood Interconnector at 16:18:15.8.[44]
- The rapid decline in system frequency did not allow any substantial governor response from these units. This is because it takes up to six seconds for these generating units to increase their active power output by 35 MW when they participate in the Contingency FCAS market. However, when a generator is not participating in the FCAS market, the governor may be disabled altogether.
- Each of the three on-line TIPS B units increased their reactive power generation from ≈20 Mega volt amps reactive (MVAr) immediately after the onset of rapid voltage decline to ≈110 MVAR at the time of system separation.
- 0.5 seconds after system separation, the three TIPS B units disconnected as soon as frequency dropped below 47 Hz.
- Of three TIPS B units, one tripped on frequency protection whereas the other two disconnected on lockout protection. The purpose of lockout relay is not just simply to trip the generator. When this trip mechanism is actuated, the generator breaker is opened, and the turbine is tripped on emergency shutdown. When the generator is tripped by lockout protection, it requires a manual reset to permit a turbine restart, hence the term "lock-out".
- The timing of CB opening to disconnect the units from the transmission system varied between 16:18:16.24 and 16:18:16.26, plus an additional 40–60 ms delay for CB opening.
- Data from the three TIPS B units shows generator current dropping to zero at approximately 16:18:16.31.

Ladbroke Grove Power Station

Figure 59 in Appendix I.2.4 shows the response of two Ladbroke Grove generating units. AEMO makes the following key observations:

- Following clearance of the sixth voltage disturbance, each unit decreased its active power generation from ≈40 MW to ≈28 MW immediately before system separation.
- Both units increased their reactive power generation from ≈15 MVAr immediately after the onset of rapid voltage decline to ≈80 MVAR at the time of system separation.
- Frequency at Ladbroke Grove was significantly different to the rest of SA, and appears to have followed the South East frequency rather than those measured at remainder of the SA system. Section 3.3.1 confirms that South East experienced an over-frequency as opposed to a declining frequency that was observed in rest of SA before the system separation. This is further corroborated by Figure 60, which shows the measured frequency on the transmission line to which these generating units are connected.
- Generator data indicates the protection system tripped the units on over voltage after the system separation when frequency at most SA nodes had declined below 47 Hz. This is consistent with the over voltages observed on the three TIPS B units following system separation, and consistent with historical responses of the SA system (see Appendix J) whereby over voltages were experienced in all previous events immediately following separation. The over voltage protection is

[44] The fastest FCAS market is for response in six seconds, which means that if generators had been dispatched to supply FCAS, it would have done little to affect the outcome.

set to trip instantaneously at 13.2 kV. After the system separation, unit 1 peaked at 14 kV and unit 2 at 13.5 kV.

- The generator current dropped to zero at 16:18:16.01 indicating when unit CBs opened (that is, 0.21 seconds after system separation).

3.3 Network performance

3.3.1 Interconnectors

Heywood Interconnector

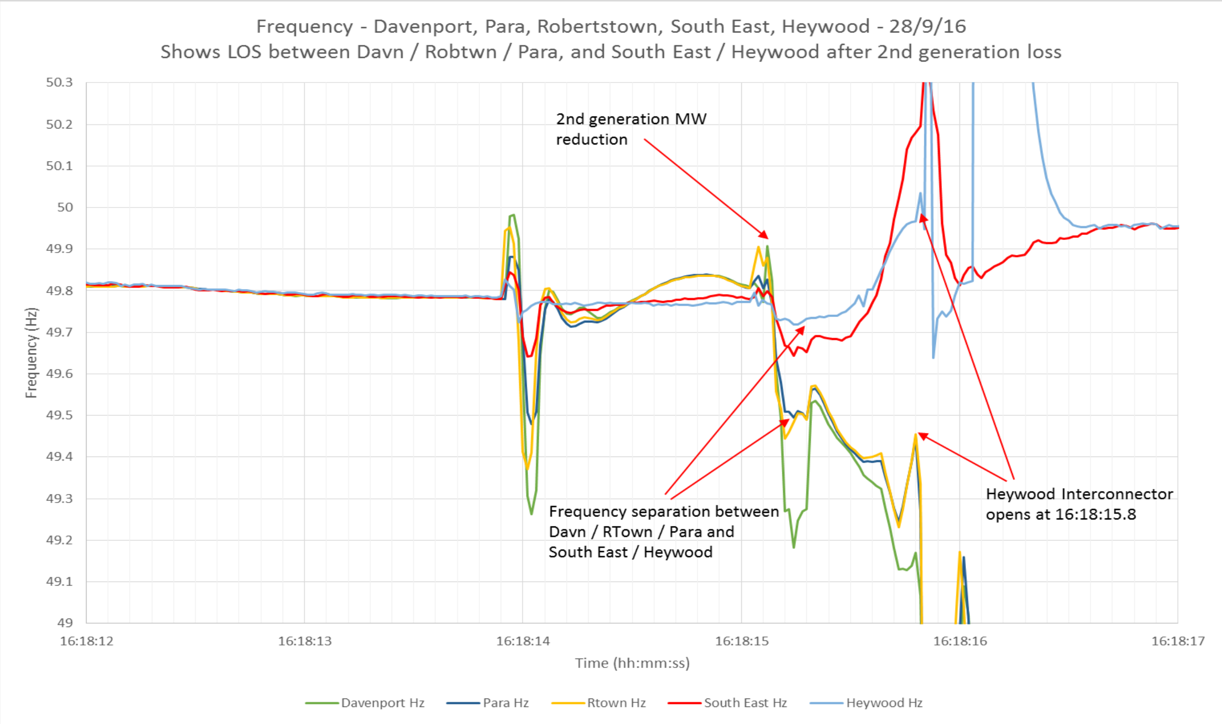
Cause of system separation

Figure 12 indicates that the frequencies measured across various nodes in the SA power system started to diverge from that measured at the Heywood Substation at around 16:18:15.2 (approximately 600 ms before the system separation).

Figure 13 highlights an upward drift in relative difference between the voltage phase angle in South East Substation and the rest of SA. This is consistent with Figure 12, as phase angle is the integral of frequency difference over a period of time.[45]

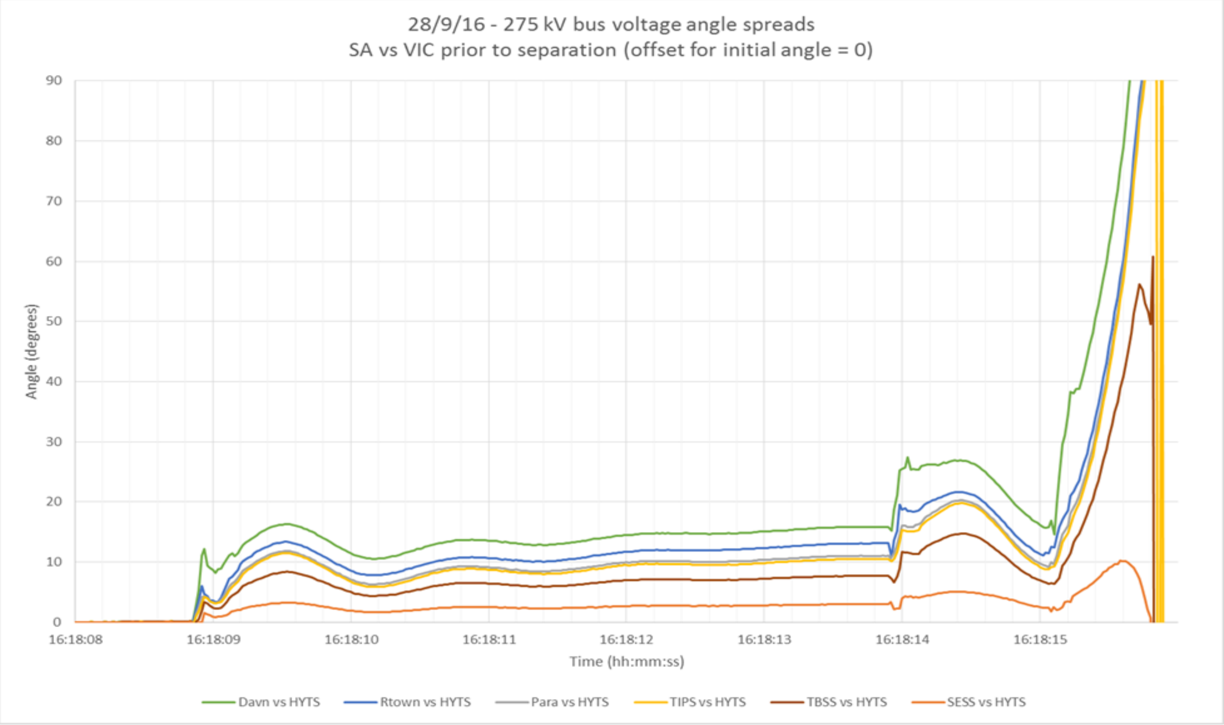
This demonstrates that disturbances caused by sustained loss of 456 MW of wind generation resulted in a rapidly growing angular difference between groups of generators in SA and the rest of the NEM immediately before the system separation. The underlying reason for relatively low variations in frequency at South East following system separation will be investigated in AEMO's final report.

Figure 12 SA system frequencies relative to the Heywood Interconnector



45 Figure 12 and Figure 13 collectively demonstrate that the natural point of separation between SA and remainder of the NEM is between South East and Para rather than between South East and Heywood substations. This is evident from an increase in the South East frequency which shows consistent behaviour to that measured at the Heywood substation until the point of separation, and negligible changes in its relative phase angle.

Figure 13 Voltage angle difference between various SA nodes and Heywood Substation



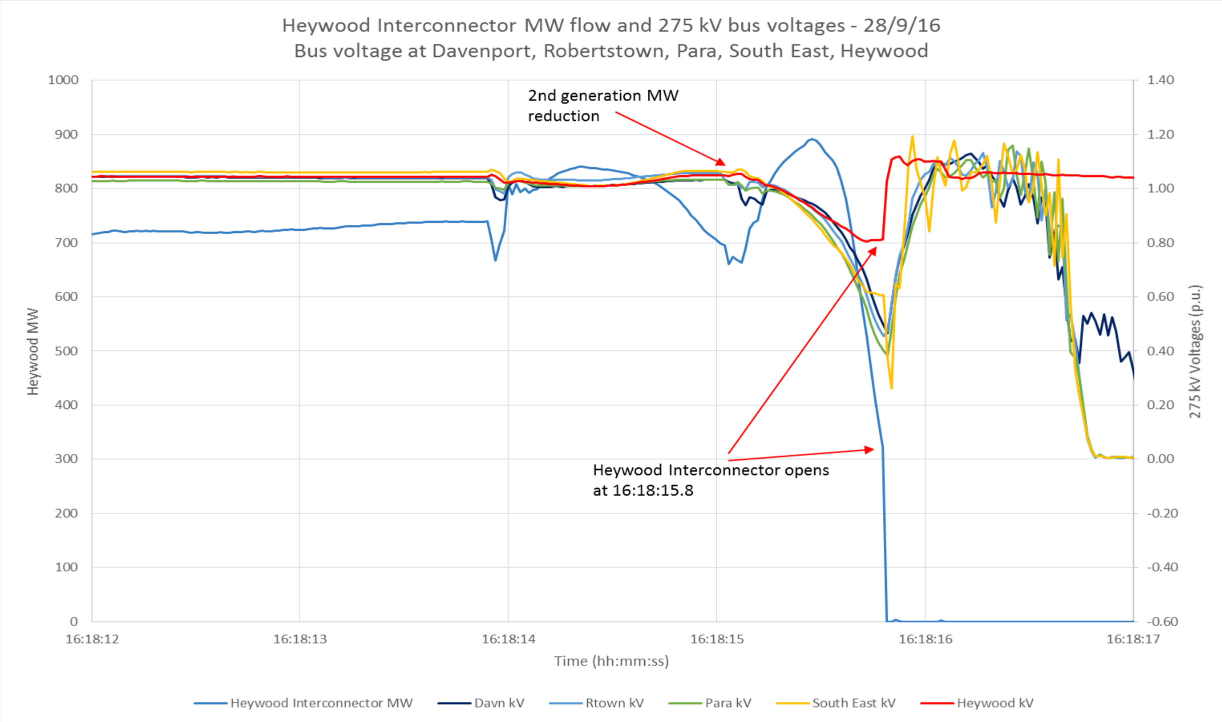
Cause of global voltage instability

An angular difference of 90 degrees is generally used to determine the onset of transient instability and loss of synchronism between two power systems. This coincides with a point in the voltage-power curve, whereby any attempt to transfer more power across the network results in a reduction in system voltages and voltage instability is inevitable. This coincidence can be described using ‘saddle node bifurcation’ theory discussed in Appendix J.

Sustained power reduction of 456 MW of wind generation gradually manifested itself as both transient and voltage instability, and voltages across all SA substations rapidly dropped before the system separation. This differs from a conventional voltage collapse problem whereby occurrence of low voltages are limited to sections of the network rather than the entire network. A conventional voltage collapse is caused by insufficient reactive power margin in parts of the network, and generally takes several seconds to manifest. This is unlike the voltage instability problem occurred on 28 September which developed in a few hundred milliseconds. A conventional voltage collapse may subsequently result in an angular instability in the system, but it is not caused by it.

Comparing Figure 13 and Figure 14 indicates that voltages across the SA power system exhibited a downward trend at the same time as the relative angles experienced an upward drift. Figure 14 shows that, unlike all other substations in SA, Davenport 275 kV voltage did not drop to zero at 16:18:17. Close inspection of this figure reveals a separate unstable island formed somewhere around Davenport 275 kV, a few seconds after the rest of SA collapsed.

Figure 14 Heywood Interconnector power flow and voltages across SA power system



Response of loss of synchronism relay

When two areas of a power system, or two interconnected systems, lose synchronism, the areas must be separated from each other quickly and automatically to avoid equipment damage and to minimise the risk of spreading the disturbance. The operating philosophy of loss of synchronism protection is discussed in Appendix J.2.

The Heywood Interconnector employs duplicate loss of synchronism relays at the South East end. This scheme is designed to separate the SA transmission network from the Victorian transmission network in the event of an unstable power swing which may prevail following contingency events.

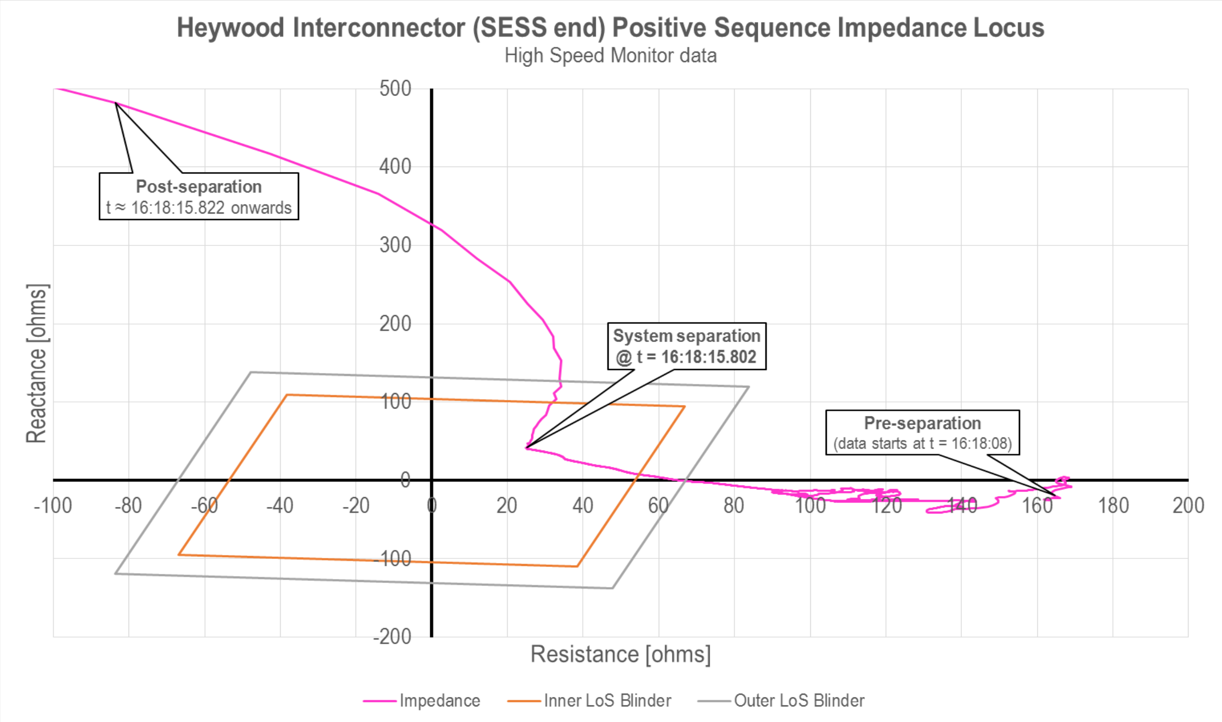
The scheme uses redundant out-of-step protections installed at South East Substation on the Heywood #1 and #2 lines to determine if an unstable power swing is taking place.

The thermal overload capability of Heywood Interconnector at the South East end is approximately 750 MVA (for up to 15 minutes) per circuit. The total power flow across the Heywood Interconnector as measured at the South East end was approximately 890 MW (1,060 MVA) at the onset of voltage collapse at 16:18:15.4. It was the combination of high currents and low voltages that resulted in activation of Heywood loss of synchronism relay rather than the sheer size of current (over-load).

Figure 15 depicts impedance trajectory against the relay operating characteristic. This figure clearly shows that the impedance trajectory crossed both inner and outer relay blinders, resulting in correct operation of the relay and opening of the associated CB. Immediately following system separation, the impedance trajectory experienced a sharp knee point.

In summary, the loss of synchronism relay operated as designed and its operation was appropriate in these circumstances.

Figure 15 Response of Heywood Interconnector loss of synchronism relay

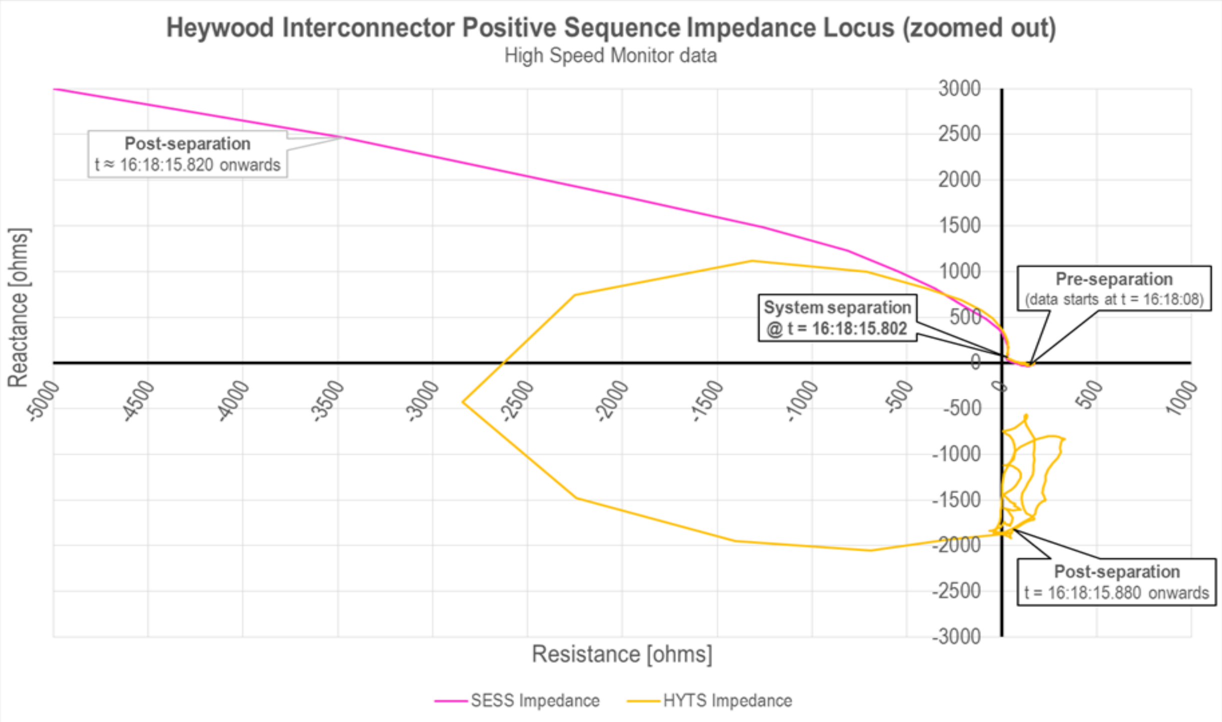


Impact on Victorian network

Figure 16 compares impedance trajectory at the Heywood and South East ends of the interconnector. The South East impedance trajectory is a zoomed out version of that presented in Figure 15.

Impedance trajectory calculated at the Heywood substation indicates that following disconnection from SA, the equivalent Victorian power system as seen by the Heywood substation resumed its stability and attempted to return to the pre-event impedance. However, it is noted that the pre-event impedance is purely resistive, as the capacitive reactance of the series capacitors installed at Black Range would somewhat cancel out inductive reactance of the transmission line. Following system separation, the apparent impedance becomes highly inductive, due to loss of reactive support from the South East reactive power support devices, and as the nearest source of reactive support for Heywood Substation was provided by Latrobe Valley generation.

Figure 16 Impedance trajectory at Heywood and South East substations



Comparison against historical SA system separation events

Unforeseen separation and complete loss of the Heywood Interconnector has occurred five times in the seventeen years since 1999.[46] Table 10 indicates that, in addition to the 28 September 2016 event, three other relevant system separation events[47] were initiated by a non-credible disconnection of generation in SA and resultant increase in the Heywood Interconnector flow, combined with declining system voltages. Appendix K compares key attributes of the three relevant events and the event on 28 September 2016 to depict active power, voltage, and frequency variations.

In all four generation-related events, disconnection of SA from the remainder of the NEM occurred due to correct operation of loss of synchronism protection between Heywood and South East substations. In all cases frequency drift can be seen between South East and rest of SA (Para is used as the frequency reference in SA) prior to loss of synchronism.

The key differentiator between the 28 September 2016 event and other three events is that there was significantly lower inertia in SA in the most recent event, due to a lower number of on-line synchronous generators. This resulted in a substantially faster RoCoF compared to the other events, exceeding the ability of the UFLS scheme to arrest the frequency fall before it dropped below 47 Hz.

All four events indicate over voltages across the SA system following system separation. AEMO will investigate this further to determine the extent to which these over voltages might undermine the ability to form a viable island.

[46] AEMO has reliable data and records back to 1999.

[47] Four separation events were mentioned in the Update Report, but one of those occurred during bushfires, so it is not relevant for present purposes.

Table 10 Previous events – complete loss of the Heywood Interconnector due to generation disconnection in SA

Date	Time	Cause of interconnector trip	Supply interrupted in SA	Duration of separation	Sufficient load was shed by UFLS prior to separation	System inertia (MW.s)	Peak Heywood flow (MW)	Frequency started to drift until system separation
2 December 1999	13:11	Trip of both units at Northern Power Station	1,130 MW	26 minutes	Yes	10693	950	2.8 seconds
8 March 2004	11:28	Runback of both units at Northern Power Station	650 MW	43 minutes	Yes	7617	825	1.7 seconds
14 March 2005	06:39	Runback of both units at Northern Power Station	580 MW	22 minutes	Yes	11127	900	2 seconds
28 September 2016	16:18	Extreme weather event caused loss of three transmission lines and loss of 456 MW of generation from nine wind farms.	1,895 MW Black System	65 minutes	No	3000	890	0.6 seconds

Murraylink High Voltage Direct Current (HVDC) interconnector

The second interconnector with Victoria, the Murraylink HVDC link (Murraylink), uses voltage source converter technology based on power electronic converters.

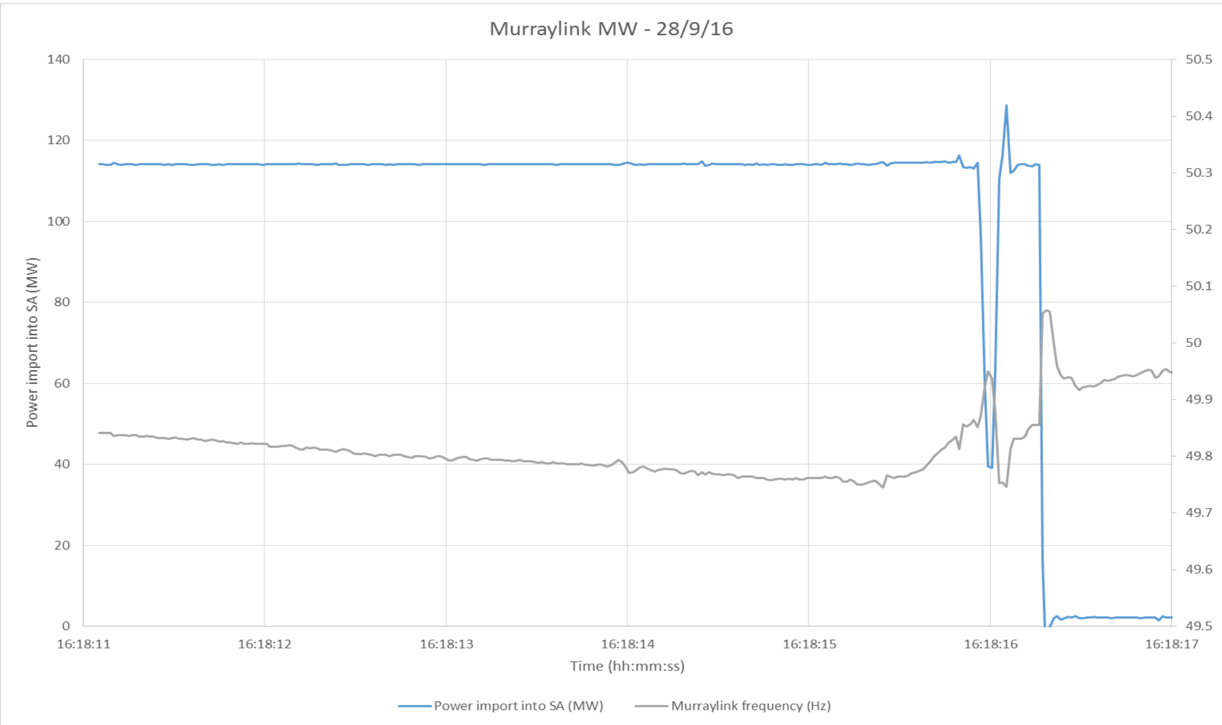
- The Murraylink design has a fast response time to voltage disturbances of less than 20 ms.
- Occurrence of a voltage disturbance causes a temporary increase of up to 150% in the HVDC link current. After around 20 ms, the nominal HVDC link current is restored.
- This means power flow across Murraylink recovers much faster from a voltage disturbance when compared to other technologies.
- The negligible decline in active power transfer across the Murraylink in response to the six voltage disturbances further confirms that its transient power reduction warrants no further consideration for this event.

The data available to AEMO at this time shows:

- Figure 17 indicates that Murraylink remained connected to the network during all faults and disturbances, maintained its pre-event active power level of 114 MW, and disconnected at 16:18:16 when SA system collapsed. This is because Murraylink requires an AC voltage supply at both the SA and Victorian ends. Loss of supply at the SA end following system collapse therefore caused its disconnection.
- Operation of Murraylink did not impact SA system performance during the six voltage disturbances between 16:17:33 and 16:18.15.

The response of Murraylink was consistent with expectations, and did not contribute to this event.

Figure 17 Power transfer across Murraylink and frequency



3.3.2 Reactive power support plant

Static Var compensators[48]

The SA transmission network includes two 80 MVAr Static Var compensators (SVCs) at the South East Substation, and two 80 MVAR SVCs at the Para Substation.

Data obtained from the two South East SVCs was not adequate to make any conclusions on the response of these two SVCs. This is because no dedicated high-speed measurement devices were connected at these SVCs.

High-resolution data was, however, available from the two Para SVCs.

Close inspection of the response of Para SVC 1 and 2, as shown in Figure 70 and Figure 71 demonstrates the following key points:

- Both SVCs contributed positively to the faults by injecting reactive power and saturating at the nominal capacity of 80 MVAr.
- Post fault response of the two SVCs and in particular SVC 2 was highly oscillatory.
- Both SVCs reduced their reactive power injection in response to declining system voltages that began at 16:18:15.2. It is noted that the decline in voltage started immediately after the clearance of the sixth fault for which reactive power contribution of the SVCs saturated at around nominal capacity.
- System separation occurred following the sustained 456 MW reduction in SA generation, and loss of synchronism due to angular instability rather than a slow evolving conventional voltage collapse (see Section 3.3.1, Cause of global voltage instability). Performance of the SVCs did not therefore play a material part in the causation chain for this particular event.
- Maintaining healthy voltages at this substation would defer initiation of loss of synchronism and operation of respective protection that disconnects SA from the remainder of the NEM. The response of all four SVCs will be further investigated in AEMO's final report, in consultation with ElectraNet.

In summary, the operation of the SVCs was not as expected, but the performance of the SVCs did not contribute materially to the Black System. The response of the SVCs will be investigated further in AEMO's final report.

Series capacitors

Two series capacitors are located at the Black Range substation, approximately half way between South East and Heywood Substations. They reduce transmission line impedance so as to improve power transfer capability, SA voltage stability, and system transient stability.

Figure 72 in Appendix L.2 shows the current across the two series capacitors and the timing at which they were bypassed. This figure indicates that the series capacitors remained connected until system separation, hence assisting system stability.

The series capacitors were bypassed immediately after the loss of the Heywood Interconnector, consistent with the installed control scheme, and did not adversely impact the sequence of events.

3.3.3 Control and protection schemes

Impedance-based relays[49]

Figure 18 indicates that a number of impedance-based distance relays operated between the system separation and Black System at both the 132 kV and 275 kV transmission lines, that is, several hundred milliseconds after the sixth voltage disturbance. These relays are expected to discriminate between fault conditions and power swings, and do not operate during power swings.

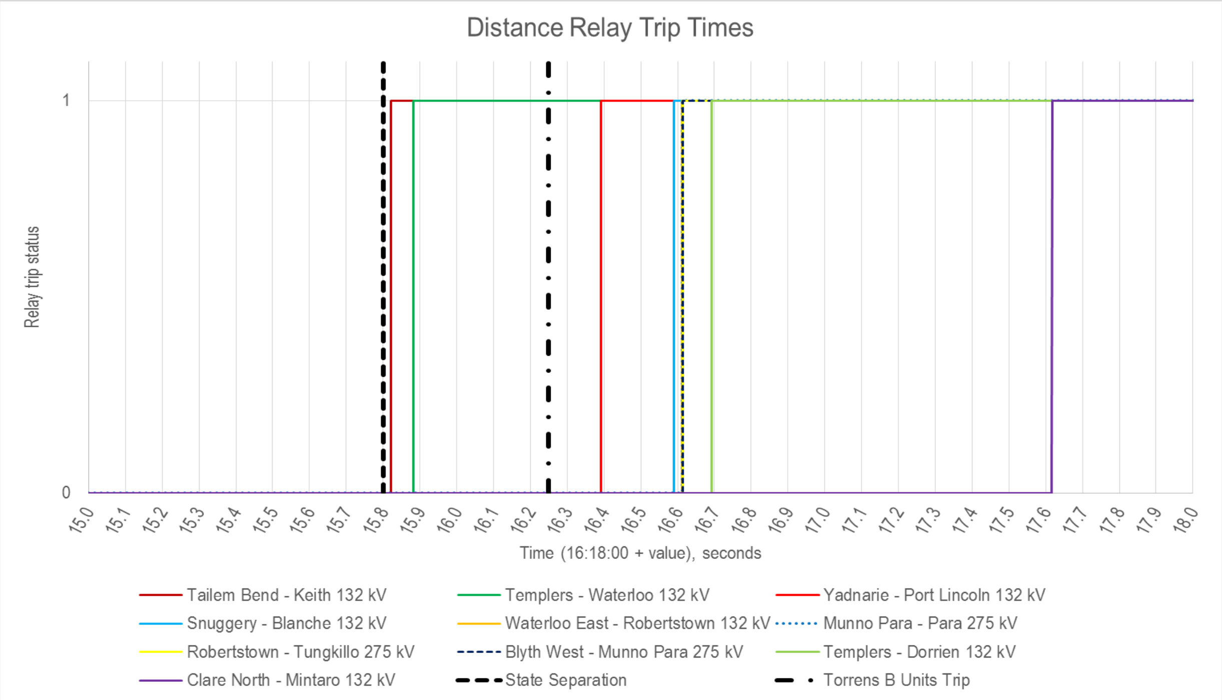
[48] Dynamic reactive power support devices comprising reactors controlled by fast action of power electronic devices, and switched capacitors. These devices provide faster control of reactive power compared to fixed shut reactors and capacitors.

[49] Protective devices which act on the ratio of voltage/current and disconnect the protected device from excessive low voltages and high currents.

Close inspection of relay data indicates that all these relays operated on three-phase distance protection. However, as discussed in this report, all six voltage disturbances were unbalanced, for which operation of three-phase distance relays should be prevented.

The operation of these relays is not considered to have contributed to the Black System, because following system separation, system collapse was occurring and inevitable. Operation of three-phase distance relays for unbalanced disturbances will be examined further in AEMO's final report to ensure this will not create material risks in other circumstances.

Figure 18 Operation of a number of distance relays before and after the system separation



Under-frequency load shedding

SA Power Networks (SAPN) records show that approximately 1150 MW of load (as measured just before the event at the load shedding CBs) was available for UFLS.

Approximately 932 MW of SAPN load was activated for load shedding by the under frequency load shedding scheme, as shown in Figure 19. For most of these loads, UFLS relays would have been expected to start to operate, but the system went black either before the relays timed out or before the CBs opened. However, this cannot be confirmed due to the low four-second resolution of SCADA data.

The distribution of load blocks currently assigned to the UFLS scheme could not respond adequately because the RoCoF of approximately 6 Hz/s was well above the 3 Hz/s level where the UFLS could be expected to operate quickly enough to maintain SA's frequency above 47 Hz. Numerous power system simulation studies carried out by AEMO indicate that for a RoCoF of up to 3 Hz/s, frequency collapse can be arrested with high confidence following SA system separation. These studies also demonstrate that with RoCoF values above 4 Hz/s the likelihood of maintaining frequency is very low.

The effect of a different distribution of load blocks than that currently in place will be investigated further by AEMO. However, the resultant benefit might be very marginal considering physical limitations of the network in terms of availability and capability of necessary CBs and relays, and availability of higher percentages of operational demand for the UFLS scheme at a given time.

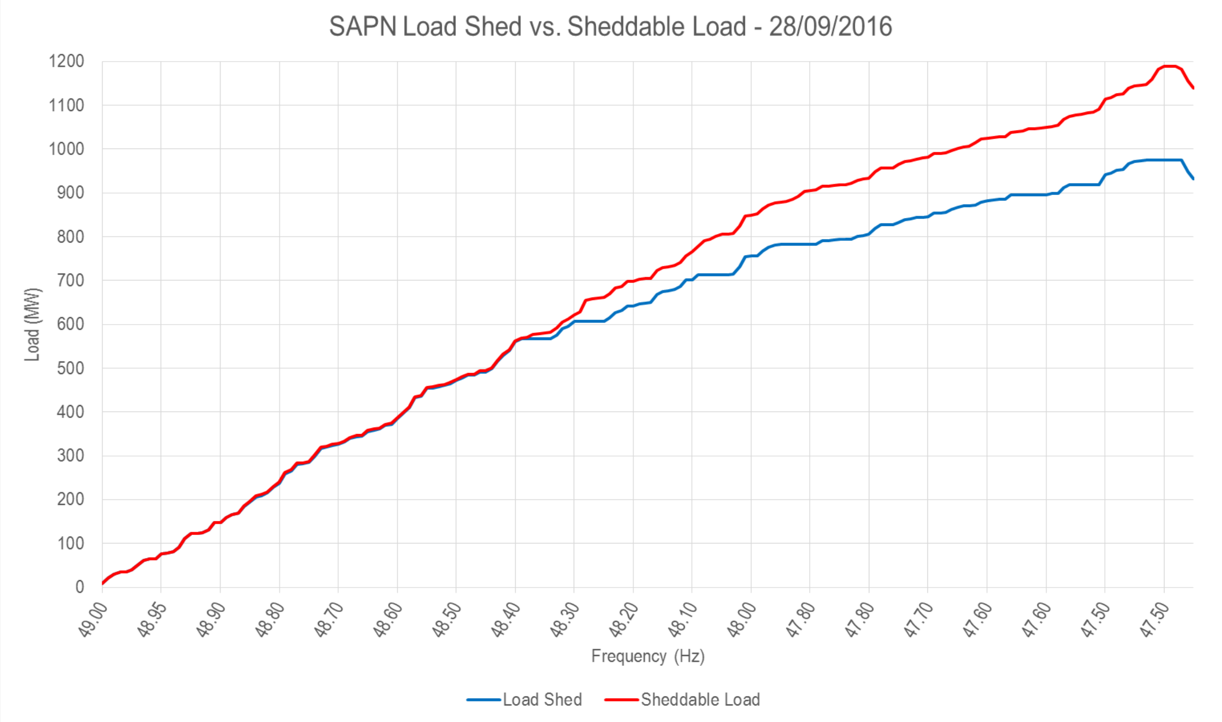
Only some of the relays with lower frequency settings (48.3 Hz and below) failed to trip, as shown in Figure 19.

Following system separation, over voltages were experienced across the SA power system. The under voltage inhibit feature of the load shedding did not therefore adversely impact the ability of the UFLS scheme.

In summary, while it is likely that some load shedding occurred after the system separation, the amount of load shed and the timing at which those loads were disconnected was not sufficient to avoid system collapse.

To maintain system stability under such high RoCoF conditions, there is a need for a system protection scheme which, in response to sudden excessive flows on the Heywood Interconnector or serious events within SA, would initiate load shedding with a response time fast enough to prevent separation, or at least to create a stable island. This will be investigated in AEMO's final report.

Figure 19 Total load shed during the event against total load available for load shedding



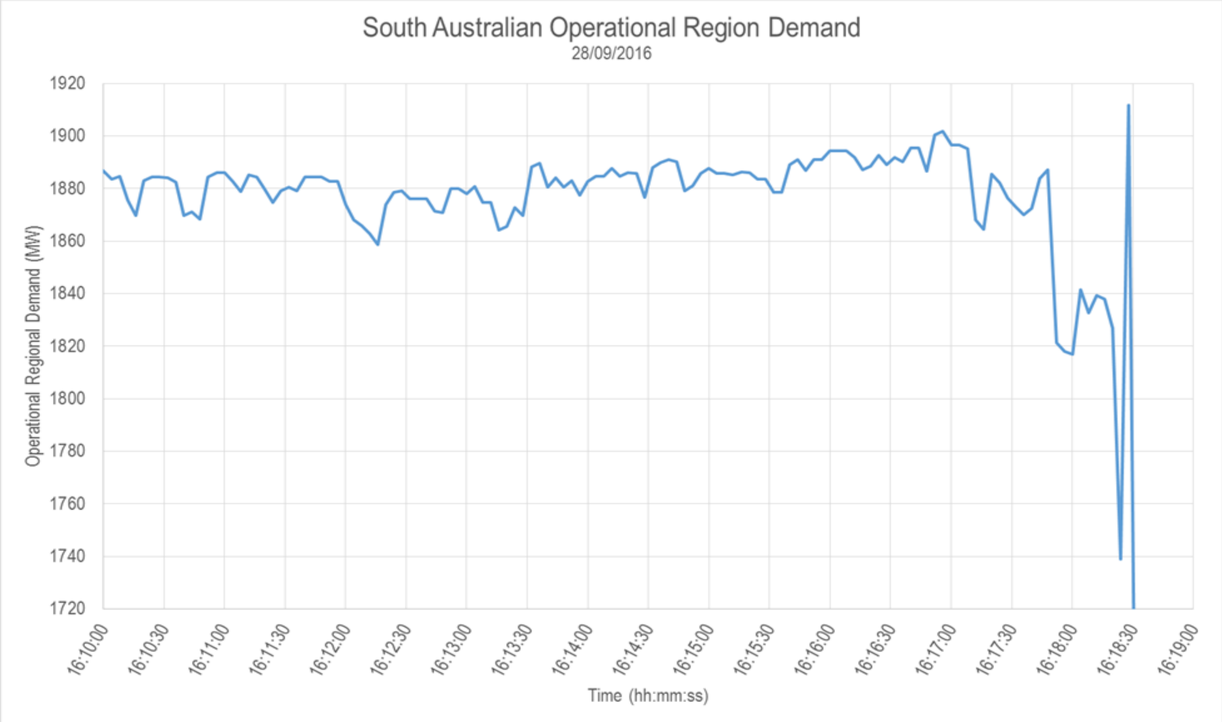
3.4 Demand response

3.4.1 Overall demand response

Figure 20 shows variations of the overall operational demand in SA shortly before and during the incident based on four-second SCADA data. This figure indicates practically no changes in the overall operational demand for the last 10 seconds before the event, including during the six voltage disturbances. The low four-second resolution of the data does not allow determination of the exact time at which SA regional demand experienced a significant reduction. However, it provides sufficient information to conclude that no substantial reduction in SA operational demand occurred prior to system separation.

There was a small reduction in demand from 1,885 MW to 1,820 MW during the sequence of six voltage disturbances just prior to the Black System. However, such a reduction would have had no significant impact on the overall situation.

Figure 20 Variations of overall operational demand in SA



3.4.2 Response of major industrial loads

Figure 21 shows three-phase voltages and active/reactive power at Olympic Dam, the largest industrial load in SA. This figure indicates that the load responded as expected and did not adversely impact system stability by drawing excessive reactive power from the grid on experiencing low voltages during the six voltage disturbances and three transmission line outages.

Figure 22 shows the response of Port Pirie load, confirming very little change prior to the Black System.

Figure 21 Three-phase voltages, active and reactive power at Olympic Dam's connection point

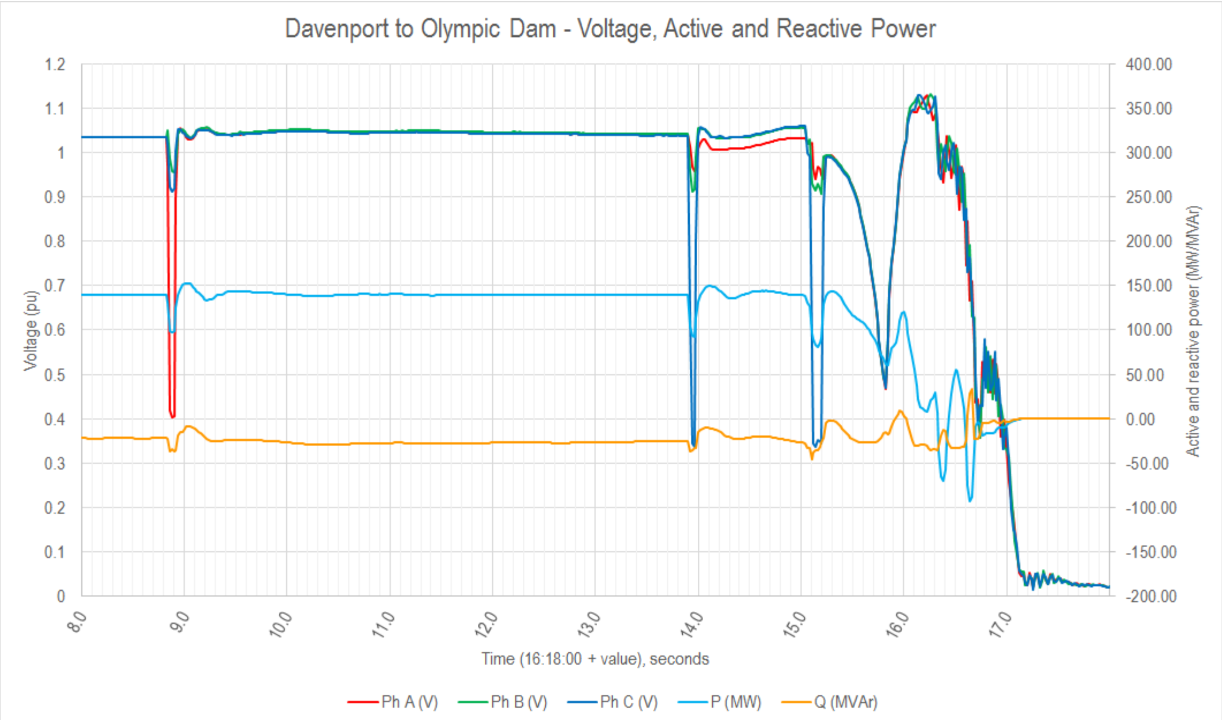
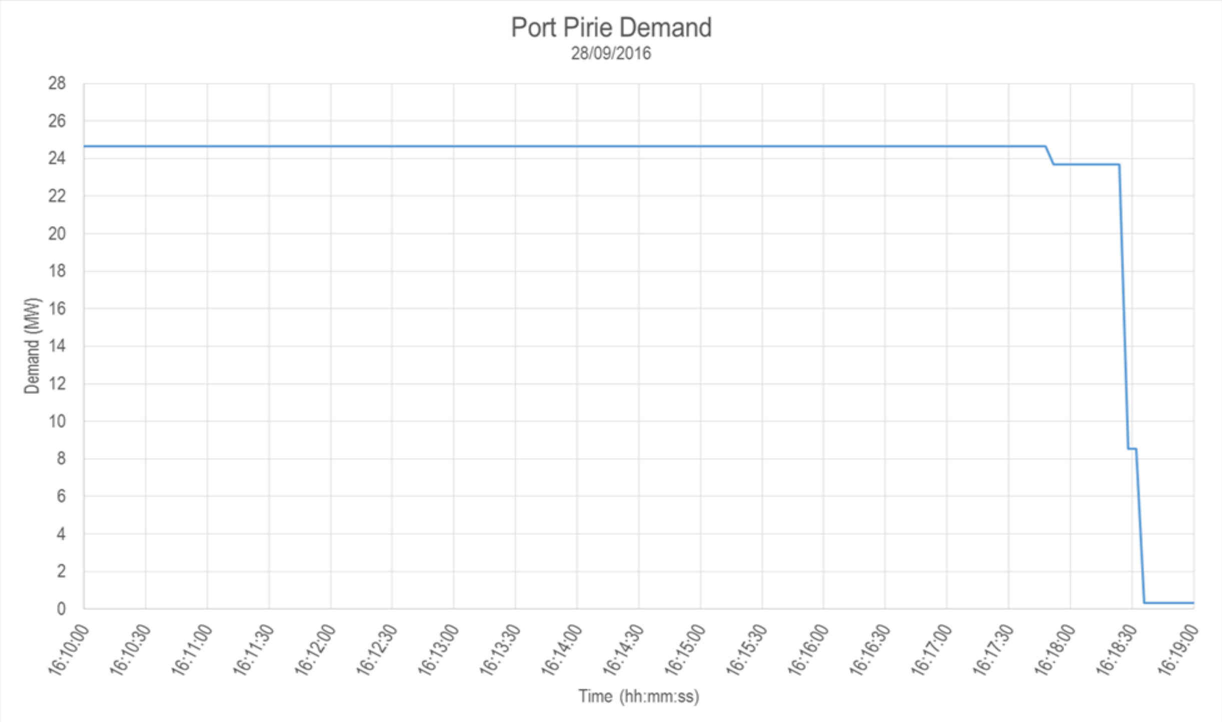


Figure 22 Port Pirie's demand variations



3.5 Scenario analysis

3.5.1 Network operability following line outages

To understand SA network capability following the loss of three transmission lines which occurred between 16:17:33 and 16:18:13, and assuming no sustained power reduction by the nine wind farms, steady-state analyses were carried out with the following three lines disconnected:

- Brinkworth–Templers 275 kV line.
- Davenport–Belalie 275 kV line.
- Davenport – Mt Lock 275 kV line.

Figure 73 of Appendix M.1 shows SA network capability with loss of the above three lines assuming that no sustained power reduction would have occurred (in reality a sustained power reduction of 456 MW was experienced).

This figure indicates that the system would likely have remained stable with a temporary overload on the 132 kV line between Waterloo and Waterloo East substations. This overloading would have been relieved by activation of automatic power runback scheme on Waterloo Wind Farm.

The same analysis was repeated with a fourth line between Davenport and Brinkworth disconnected (as occurred after the Black System). Figure 74 highlights that no further thermal overloading of the transmission lines or under voltages would have been experienced indicating stability and operability of the remainder of the SA power system despite loss of four transmission lines.

Network transfer capability following line outages

This section presents results obtained from steady-state analyses which determine power transfer capability and reactive power margin along SA's three major transmission corridors following loss of the three and four lines discussed above and assuming no sustained power reduction associated with nine wind farms as a result of the faults.

Based on AEMO's initial static modelling, it seems likely the SA grid could have withstood the loss of all three power lines, and the fourth damaged after the Black System.

Static modelling is an indicator of a possible scenario in a point in time. AEMO may do further dynamic modelling, but still cannot predict what additional events might have affected the SA power system beyond the time of the Black System as the storm front continued its progress through the state

Heywood Interconnector transfer capability

The following key observations can be made about the transfer capability between South East and Heywood circuits (see Appendix M.3):

- 750 MW of power could most likely have been transferred across South East–Heywood circuits while maintaining healthy voltages even with loss of four circuits in the Davenport area (see Figure 75).
- Line outages in the Davenport area:
  - Have no material impact on Heywood transfer capability. Comparison of Figure 76 and Figure 77 provides further evidence that these line contingencies would likely have had no noticeable impact on reactive power margin at South East substation.
  - Would have been likely not to have resulted in a noticeable voltage decline at South East area. Figure 76 and Figure 77 indicate the presence of sufficient reactive power margin at this substation.

Transfer capability from Adelaide to Davenport

The following key observations can be made about the transfer capability between Davenport and Adelaide area (see Appendix M.4):

- Line outages in the Davenport area would likely have impacted the ability to maintain Davenport voltages. Comparison between Figure 79 and Figure 80 illustrates a reduction in reactive power margin at Davenport with three and four line contingencies. Despite this reduction in reactive power margin, the system could probably have been operated within the envelope defined in System Standards specified in Schedule 5.1a of the NER, with all voltages within the continuous uninterrupted operating range.
- The maximum supportable active power demand at Davenport would likely have been approximately 250 MW, which would probably have been adequate to meet the local demand including Olympic Dam (see Figure 78).[50]
- While the power system around Davenport would likely have been in a satisfactory operating state with only one line in service, ongoing voltage control would likely have been very difficult.

Transfer capability from Robertstown to Adelaide

The following key observations can be made about the transfer capability from Robertstown to Adelaide area (see Appendix M.5):

- Line contingencies in the Davenport area would likely have had no adverse impact on Robertstown to Adelaide transfer capability as shown by Figure 80.
- Comparison of Figure 82 and Figure 83 provides further evidence that these line contingencies would likely have had no noticeable effect on reactive power margin at Para, which is a critical bus that supports Adelaide demand.
- Line contingencies in the Davenport area would not have resulted in any voltage decline at Para, due to presence of sufficient reactive power reserves at Para as shown by Figure 82 and Figure 83.
- Line contingencies in the Davenport area would have been likely to have resulted in higher Robertstown transfers, due to higher injection of wind generation into Robertstown rather than into Davenport.

The network would thus probably provided adequate transfer capacity despite the loss of the four lines.

[50] However, as described in Section 4.4, attempting to restore this load with such a network configuration, as opposed to continuing supply, is much more onerous.

3.5.2 System strength and available fault levels

System strength is an intrinsic characteristic of the local power system, and primarily depends on the quantity of nearby on-line synchronous generators. It is a measure of stability of generating systems' control systems and network dynamics to ensure that the system can remain within a normal steady-state condition or return to normal steady-state conditions following a disturbance.

To determine the extent to which system strength and fault level had affected the response of wind farms to the six voltage disturbances, simple calculations were carried out using the conventional method for calculation of the short circuit ratio (SCR)[51], as well as more detailed weighted short circuit ratio (WSCR) calculations (see Appendix N).

Table 11 presents SCR and WSCR for all on-line wind farms North of Adelaide immediately before the loss of three transmission lines and sustained reduction of 456 MW of wind generation. Note that for SCR calculations each wind farm is treated in isolation, whereas with the WSCR calculation method the impact of all adjacent wind farms is accounted for. The WSCR would therefore give rise to a more pessimistic assessment of the system strength, and can be considered as a good indication of minimum system strength.

Wind farms were grouped based on electrical and geographical proximity. Therefore Hallett, Hallett Hill, Hornsdale, North Brown Hill, and The Bluff wind farms were considered as part of a larger virtual wind farm. All other wind farms were treated in isolation. This means their SCR and WSCR are identical, because SCR and WSCR produce different results only when two or more wind farms are considered as part of a larger cluster.

Table 11 Short circuit ratio and weighted short circuit ratio calculated for all on-line wind farms north of Adelaide

Wind farm	SCR at 33 kV wind turbine terminals	WSCR at 33 kV wind turbine terminals
Clements Gap	11	11
Hallett	6.9	2.9
Hallett Hill	6	2.8
Hornsdale	6.2	3.1
North Brown Hill	5.2	2.8
The Bluff	10.3	3.4
Mt Millar	2	2
Snowtown II	4.6	4.6
Waterloo	4.4	4.4

Comparison of these calculations with the minimum SCR withstand capability of wind turbines, as confirmed by each original equipment manufacturer to AEMO, demonstrates that all wind turbines were operating above the minimum SCR for which they were designed.

All wind farms successfully rode through the voltage disturbances until the pre-set protection limit of 3 or 6 was reached or exceeded, and did not indicate any issues that manifest specifically when operating in low system strength conditions.

Transient stability limit equations are calculated by ElectraNet and provided to AEMO. ElectraNet has advised that the most recent limit equations provided to AEMO have considered higher renewable penetration levels, and hence a weaker system. A weaker system will generally result in reduced transfer limits.

There would likely have been sufficient system strength and available fault level provided the Heywood Interconnector remained in service. However, this may not have been the case if separation had occurred, even if the resulting island remained viable. This risk will be investigated further.

[51] SCR is ratio of the fault level (MVA) and the rating of the wind farm connection (MW).

3.6 Preliminary conclusions – primary causes

Electrical faults

Close inspection of the BOM's report[52] demonstrates it is unlikely that lightning strikes caused any of the five electrical faults and six voltage disturbances. Information obtained from the BOM indicates tornadoes as a very likely cause of the five electrical faults that occurred before the system separation.

Generation reduction

Investigations now show that there was a total sustained reduction of 456 MW of wind generation across nine wind farms, plus further transient reductions of 42 MW after the clearance of the sixth voltage disturbance.

Nine wind farms exhibited sustained power reduction during the six voltage disturbances on the transmission system:

- Eight of these wind farms are categorised as Group A and B in this report. Group A and B wind turbines have a protection system that takes action if the number of ride-through events in a specific period exceeds a pre-set limit. This protection feature was unknown by AEMO prior to this event.
- Wind turbines categorised as Group C do not have any pre-set limit for the number of permitted fault ride-through events. The sustained power reduction by Group C wind turbines was caused by zero power mode fault ride-through response of those turbines (resulting in both active and reactive power to drop to zero temporarily) and slow active power recovery of 8 MW/s.

In addition to 456 MW of sustained reduction in wind generation, 42 MW of transient reduction was experienced due to natural fault ride-through response of remaining wind farms which do not immediately recover active power to pre-event level.

System separation

The sustained loss of 456 MW of generation increased flows on the Heywood Interconnector. This caused the relative voltage phase angle of the Heywood Interconnector measured at SESS, and that of the remainder of the SA power system, to exceed 90 degrees immediately before the system separation. This is an indicator of transient instability or loss of synchronism between the groups of generators in SA and those in the rest of the NEM. At the same time, and for the same reason, voltages across the SA power system started to decline.

The Heywood Interconnector uses an automatic protection mechanism which disconnects SA from the remainder of the NEM when a loss of synchronism is detected. This protective function operates based on the ratio of voltage to current (impedance). Declining system voltages and increased flow over the Heywood Interconnector resulted in the apparent impedance seen by the loss of synchronism relay reaching its trip setting. This led to correct operation of the loss of synchronism relay, and disconnection of the Heywood Interconnector.

Voltage instability

A rapid decline in voltage across the SA network was observed immediately prior to the tripping of the Heywood Interconnector. This rapid voltage decline was consistent across the SA transmission network from the south-east to the north.

This observed reduction in network voltages is consistent with the loss of synchronism between the SA power system and the remainder of the NEM caused by the relative phase angle between the two systems exceeding 90 degrees.

Once separated from the rest of the NEM, network voltages within SA momentarily returned to normal levels, before the rapid frequency fall led to the Black System.

[52] BOM "Severe thunderstorm and tornado outbreak South Australia 28 September 2016" http://www.bom.gov.au/announcements/sevwx/

Voltage instability began after clearance of the sixth voltage disturbance and sustained generation reduction of 260 MW associated with three wind farms (Groups B and C). This indicates that system voltages were stable and would likely have remained stable if angular instability and accompanying rapid decline in the voltage, due to loss of wind generation, had not occurred.

Frequency instability

Following separation from Victoria, voltages across SA momentarily returned to the continuous uninterrupted operating range. However, a viable island could not be established and voltages and frequencies collapsed shortly after across SA.

The key reason for the failure of five on-line synchronous generators and five remaining wind farms to form a viable island was that frequency in various SA nodes fell rapidly following loss of the Heywood Interconnector. It dropped below 47 Hz in most parts of the SA island, at which point all synchronous generators and wind farms are permitted to disconnect, according to clause S5.2.5.3 of the NER.

This rapid decline in frequency stemmed from 966 MW net loss of supply (510 MW on the Heywood Interconnector and 456 MW of wind generation). The resultant RoCoF of approximately 6 Hz/s was well above the 3 Hz/s level where the UFLS could be expected to operate sufficiently quickly to maintain SA frequency above 47 Hz.

Historically, the RoCoF following a separation between SA and Victoria has been below 3 Hz/s, which has allowed UFLS to operate and avoid a total Black System. However, during this event, the proportionally low amount of conventional generation dispatched in SA at the time of separation, and the subsequent low inertia, resulted in a higher RoCoF than had been experienced during previous separation events.

Without any substantial load shedding following the system separation (see Section 3.3.3), the remaining generation was much smaller than the connected load and unable to maintain the islanded system frequency. As a result a total Black System occurred. This would likely have occurred even with successful operation of UFLS scheme resulting in 60% of SA load being shed on time. This is because the remaining load of approximately 800 MW, after UFLS action, would still be too great for the remaining generation to maintain the islanded system frequency. At the point of separation, frequency collapse and consequent Black System was therefore inevitable.

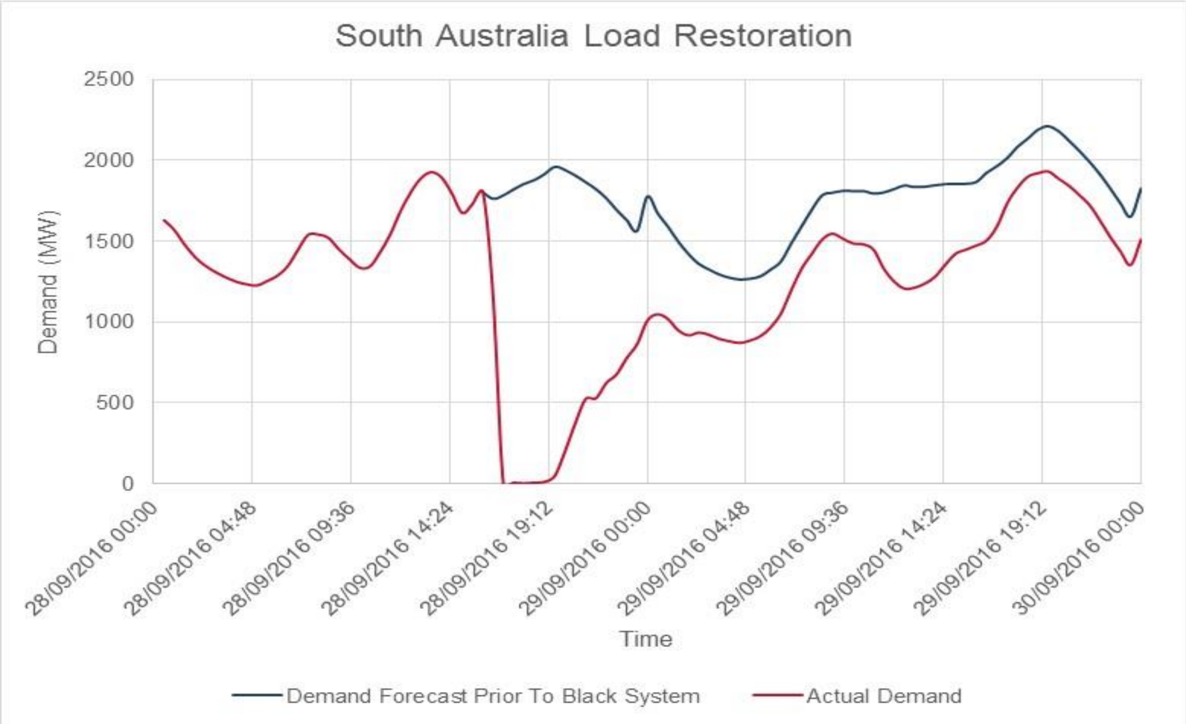
4. RESTORATION

This section sets out the roles and responsibilities of the different organisations involved, and details of AEMO's restoration strategy used to restore the power system and load in SA. More detail on the restoration process is in Appendix Q.

AEMO would like to acknowledge the efforts of all parties involved during the restoration process, and their contribution in restoring the power system and customer load in difficult circumstances. See Appendix O for a summary of the roles and responsibilities of the various organisations involved.

To summarise, Figure 23 illustrates the restoration of consumer load following the SA region Black System as a comparison between the forecast load for SA and the load actually supplied.

Figure 23 Comparison of forecast and actual load



4.1 Restoration strategy

4.1.1 General concepts

The basic restoration sequence can be broken down into three major steps, each of which must be completed before moving onto the next. These stages are:

1. Secure and make safe the power system.
2. Provide auxiliary supply to power stations.
3. Load restoration.

Appendix Q gives an overview of the restoration process.

The primary objective of any system restart plan is to provide auxiliary supply to generating units to allow them to commence their restart processes as quickly as possible. This is done by restoring transmission networks between the generating units that will provide System Restart Ancillary Services (SRAS) and other power stations' auxiliary loads. Other load may be restored during this process, but only if it is required to stabilise the power system.

The restoration of the power system must be undertaken as quickly as possible, but it must also be systematic and deliberate to avoid additional disruptions that would potentially extend the duration of the restart process.

4.1.2 Safety considerations

Proceeding without a clear understanding of the status of the network and what is available could result in safety risks to the public and industry personnel, and damage to the power system and generating units.

Once the status of the power system is assessed, preparation for system restoration may commence. This includes making equipment safe prior to any restoration activities, through liaison with TNSPs, DNSPs, and Generators.

Each step in the process must be implemented, assessed, and confirmed before proceeding to the next stage. This is critical due to the potentially unstable state of the partially restored power system.

4.2 Restoration sequence of events

At 1630 hrs on 28 September 2016, AEMO and ElectraNet agreed on a restoration strategy. The strategy consisted of using two separate plans in parallel to restore auxiliary supply to the power stations in the Torrens Island area and high priority loads:

- One plan was to use the SRAS[53] at Quarantine Power Station[54] (QPS).
- The second plan was to import electricity to SA through the Heywood Interconnector from Victoria.

This was the quickest and safest way to restore supply to SA[55], and allowed segregation between restart paths to provide another level of redundancy, in case one method encountered difficulties.

AEMO initially excluded the northern areas of the state from the restoration process, due to extensive damage to transmission assets in the area. A priority safety concern was reports of transmission lines down over roads, north of the Hummocks–Waterloo–Robertstown lines.

In accordance with standard industry practices to protect public safety and the safety of ElectraNet's field crews, the transmission lines north of the Adelaide metropolitan area could not be re-energised before visual inspection. Continued poor weather conditions and high winds kept helicopters grounded, making slower ground patrols of the transmission network necessary. This was not completed until the next day.

Chronological details of the restoration process are in Appendix R.

4.2.1 Use of SRAS provided by Quarantine Power Station

AEMO issued an instruction to QPS to provide SRAS at 1637 hrs. Limited auxiliary supplies were provided to the Torrens Island A and Torrens Island B power stations by 1713 hrs.

Due to problems with SRAS from QPS, the provision of auxiliary supply from the SRAS was not completed before supply to the Torrens Island area was made available from the Heywood Interconnector. This is discussed further in Section 5.

4.2.2 Use of interconnection to Victoria

There are two interconnections between SA and Victoria:

- The Heywood AC Interconnector consists of two parallel 275 kV transmission lines between Heywood Substation in Victoria and South East Substation in SA. These lines remained energised from Heywood after the Black System.

[53] Details of SRAS contracts are normally considered as confidential information, but AEMO has obtained permission from the operators of the SRAS in SA to provide limited details.
[54] Refer to Section 5 for further information on the SRAS.
[55] Wind farms cannot be used in the initial stages of a power system restoration for technical reasons including the variable nature of their output.

- The Murraylink Interconnector is a single DC line between Redcliffs 220 kV Substation in Victoria and Monash 132 kV Substation in SA. Murraylink requires an AC supply at both ends prior to connection, so it cannot be used as a black start source.

Before commencing switching on the Heywood Interconnector, the following was necessary:

- Confirmation that no protection and/or security issues existed. AEMO consulted with the asset owner (AusNet Services) prior to reaching this conclusion.
- To ensure public safety, ElectraNet carried out other high priority switching related to the storm damage.

Switching began at 1723 hrs to establish a transmission corridor between Heywood and Torrens Island, with the aim of providing additional capacity to restart generating units in this area.

Extensive and complex switching was required to restore the power system between Victoria and Torrens Island in SA. By 1828 hrs, a connection from Victoria to Torrens Island in SA had been established. At 1843 hrs, auxiliary supplies to the Torrens Island ‘A’ & ‘B’ power stations were swapped over from the SRAS supply to the interconnection supply. Further attempts to utilise QPS were abandoned at this stage.

Further switching was then begun to provide support to this initial single path and to re-energise the transmission network in the Adelaide area before starting any load restoration. A second connection from Victoria to Torrens Island was established at 1906 hrs, and extended to Pelican Point Power Station by 1931 hrs, in accordance with the system restart plan.

Clearance to restart generating units at Torrens Island A and B Power Stations was given at 1854 hrs, and to Pelican Point Power Station at 1950 hrs.

4.3 Generation

Table 12 shows the major generating units in SA that were restored to service between 1950 hrs on 28 September 2016 and 0240 hrs on 29 September 2016.

Table 12 Generating units returned to service

Date	Time	Generating unit	Available capacity (MW)
28 Sep 2016	1950 hrs	Quarantine units 1–4	100
	2100 hrs	Torrens Island A2	120
	2200 hrs	Torrens Island A4	120
	2225 hrs	Pelican Point	175
	2330 hrs	Torrens Island B1	200
29 Sep 2016	0240 hrs	Torrens Island B3	200

Quarantine units 1–4 were not on-line to supply normal load prior to the Black System, and were started after house supply to the Torrens Island A & B power stations had been restored via the Heywood Interconnector. Quarantine unit 5 was not available due to the issues associated with the provision of SRAS.

Neither Torrens Island A2 nor A4 generating units were on-line prior to the Black System event, but they were both still warm as they came off-line at around 0100 hrs on 28 September 2016. Both units were synchronised within approximately 3.5 hours of receiving clearance to restart, and five hours after the restoration process commenced.

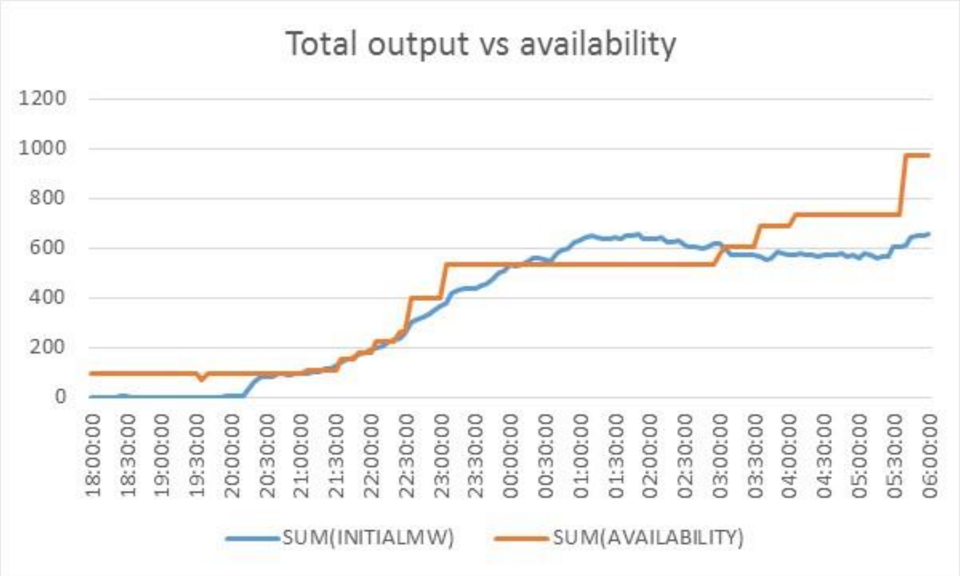
Pelican Point Power Station was off-line prior to the Black System, having shut down at around 0030 hrs on 28 September 2016. At 1836 hrs, Engie advised AEMO that a gas turbine (GT) at Pelican Point could be on-line four hours after restoration of local supply. Supply to Pelican Point was provided via the interconnection to Victoria at 1950 hrs, with a Pelican Point GT on-line at 2230 hrs. This was approximately 2.5 hours after auxiliary supply was restored, and six hours after the restoration process commenced.

Both of the Torrens Island B units were on-line at the time of the Black System. Full auxiliary supply was restored at 1843 hrs, just under 2.5 hours after the units tripped. The first unit was synchronised approximately five hours after the event, and the second unit eight hours after the event.

Appendix S shows the output of each of these units. There were no unexpected delays in ramping to maximum capability of the particular generating unit. The ramp rates of all units were in accordance with expectations during normal operation.

Figure 24 shows the total output of the generating units listed in Table 12 versus the availability of the units.

Figure 24 Total unit generating output versus availability



Attempts were made to start the Dry Creek Power Station[56], however this failed due to problems with the auxiliary supply switchboards at the power station.

Osborne Power Station was not available due to ongoing maintenance works.

In accordance with AEMO's system restart procedures, wind farms were not reconnected in the early stages of the restoration process due to the potential impact of the variable nature of their output on frequency and voltage control. The Lake Bonney wind farms were given clearance to reconnect at around 0100 hrs on 29 September 2016 to assist with voltage control. Other wind farms were given clearance to reconnect when connections and transmission capacity became available.

4.3.1 Generation delays

If SRAS from QPS had operated as expected, clearance to restart the Torrens Island generating units would likely have been given approximately one hour earlier, at 1730 hrs. AGL[57] has advised AEMO that if clearance to restart generating units had been given earlier, it is likely the generating units would have been returned to service earlier.

Similar delays, for the same reason, were experienced with restoring generation at Pelican Point Power Station.

4.3.2 Port Lincoln area

This section is based on information provided by ElectraNet and Engie.[58]

56 Dry Creek Power Station has three 45 MW gas turbine units.
57 AGL is the operator of the Torrens Island A & B power stations.
58 Engie is the operator of the Port Lincoln Power Station.

Port Lincoln has three generating units that are capable of supplying the local load when the transmission network connection is unavailable.

Following the Black System, ElectraNet advised Engie that the Port Lincoln generating units were to be started in accordance with its Network Support Agreement.[59] All three generating units were successfully started, and supply to the Port Lincoln load was restored at 1915 hrs on 28 September 2016. Port Lincoln Unit 3 was being used to manage the frequency in this small islanded network.

At 0053 hrs on 29 September 2016, Port Lincoln unit 1 and unit 2 both tripped unexpectedly. Following the trip of units 1 and 2, unit 3 was taken off line due to frequency control issues. This resulted in the loss of supply to the Port Lincoln area.

A number of attempts were made to start unit 3 on 30 September, however, the unit continued to experience frequency control issues. Unit 3 was returned to service at 1505 hrs on 30 September and was able to generate power, although the frequency control issues were continuing.

Due to damage to the transmission network between Port Lincoln and Yadnarie, the Port Lincoln generation could not be utilised elsewhere.

At 2048 hrs on 30 September, following repair of the Port Lincoln to Yadnarie transmission line, unit 3 was shut down. This allowed the reconnection of the Port Lincoln load to the main transmission network at 2055 hrs on 30 September, with all load being restored in the Port Lincoln area shortly thereafter.

Following further adjustments to unit 3, it was made available for service on 1 October. Units 1 and 2 were made available for service on 8 October.

Engie is finalising its detailed investigation into the operation of the Port Lincoln units on 28–29 September 2016, and will be in a position to provide a more detailed statement once this investigation is complete. Engie has advised AEMO that this investigation will be completed by the end of December 2016.

4.4 Load restoration

Load restoration commenced at approximately 1900 hrs on 29 September 2016.

Load restoration was initially achieved via the Heywood Interconnector, and supplemented by generation in SA as it became available.

Load restoration was halted temporarily at around 2040 hrs, because flow on the interconnector was around 100 MW above the interconnector limit of 300 MW.[60] Load restoration began again at around 2115 hrs, as generation from the power stations on Torrens Island became available.

By 2030 hrs (four hours after the Black System), approximately 40% of the load that was available for restoration was restored. By midnight on 28 September 2016 (7.5 hours after the Black System), approximately 1,000 MW or 80–90% of load that could be restored had been restored.[61]

Although AEMO gave clearance to restore all remaining load at 1829 hrs on Thursday 29 September, approximately 34% of forecast load (mainly in the northern part of the network) could not be restored due to damage to the transmission network. Load in this area was progressively restored over the next few days as repairs to the transmission network were completed.

Table 13 shows the restoration sequence of the major industrial loads fed from the Davenport substation. The timing of the restoration was based on two factors:

- Initially no connection was available to Davenport substation from the south, due to actual or potential damage to all transmission lines. The first transmission line to Davenport (Davenport–Bungama 275 kV line) was returned to service at 1215 hrs on 29 September after completion of line patrols. This allowed partial restoration of the loads in the northern area of the state.
- After the Davenport–Bungama line was returned to service, the capability of supplying the load in the area was limited due to voltage control issues with only this single line in service.

59 This is a contractual agreement between the operator of the Port Lincoln generator and ElectraNet. This agreement is normally activated by ElectraNet when the single 132 kV transmission line supplying Port Lincoln is out of service.
60 This limit was based on conservative estimates of the system capability at the time. The limit was increased to 400 MW at 2050 hrs.
61 Or approximately 64% of the load at the same time the previous day.

Full load capability was restored after a second line to Davenport (Davenport–Belalie 275 kV line) was returned to service after repairs at 1340 hrs on 10 October 2016.

All load in SA was restored by 11 October 2016.

Table 13 Load restoration in the northern part of the state

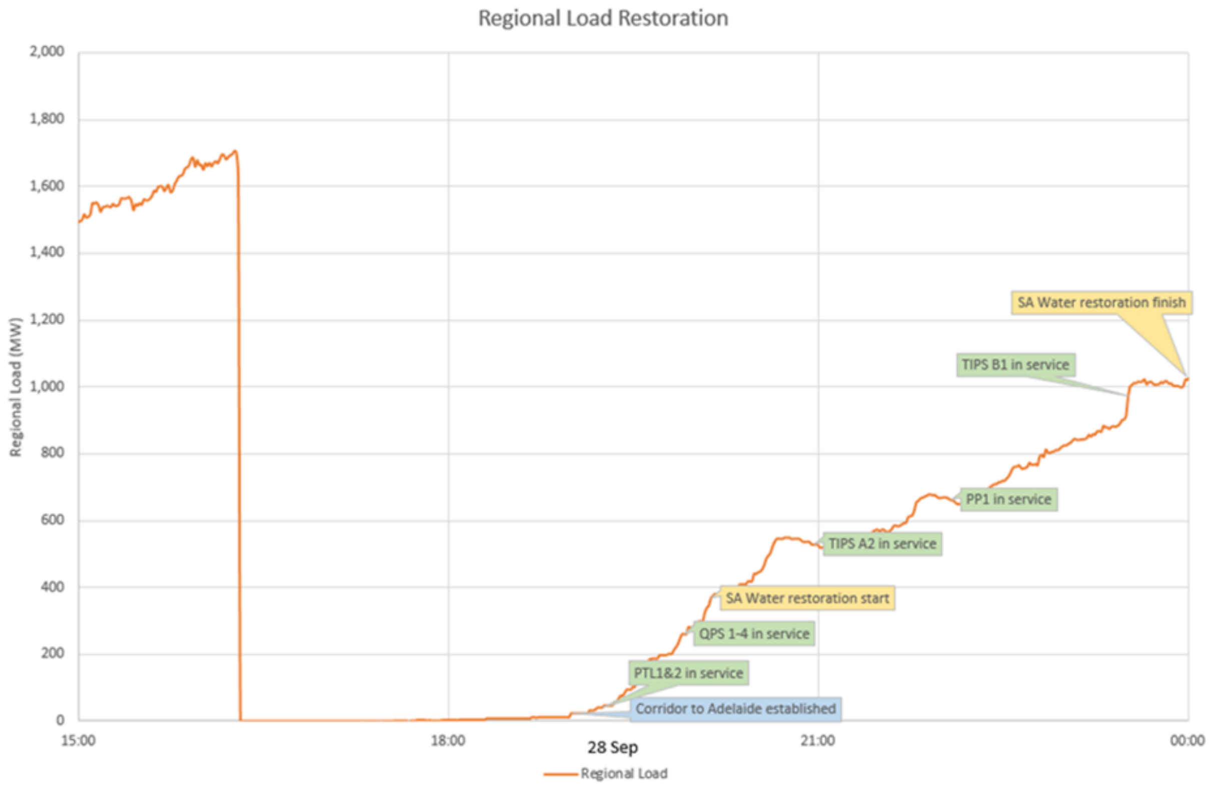
Connection Point / Load	First energised	Maximum permissible load	Full load capability restored
Whyalla Central (Arrium Steel Works & SA Power Network customers))	1655 hrs on 29/09/2016	Initially 30 MW total pending further network studies by ElectraNet. Increased to 46 MW total (Arrium Steel 26 MW) at 1800 hrs on 4/10/2016	1700 hrs on 10/10/2016
Middleback (Arrium Mine)	1930 hrs on 29/09/2016	2 MW (pending further network studies by ElectraNet)	1800 hrs on 4/10/2016
Olympic Dam 132 kV connection (this is a standby supply and not normally required if the 275 kV connection is available)	1840 hrs on 30/09/2016	20 MW (as requested by BHP)	1700 hrs on 6/10/2016
Whyalla Central (Arrium Ladle Metallurgical Furnace (LMF))	ElectraNet advised Arrium connection point available to energise at 1930 hrs on 5/10/2016. Arrium commenced taking load 0520 hrs on 6/10/2016.	20 MW (normal full load)	0520 hrs on 6/10/2016
Olympic Dam 275 kV connection	ElectraNet were ready to energise the line at 1615 hrs on 10/10/2016 but BHP requested a delay until 0730 hrs on 11/10/2016	No limit	0730 hrs on 11/10/2016

In Section 3.5.1, it was noted that the power system around Davenport would likely have been in a satisfactory operating state with only one line in service, but that ongoing voltage control would have been very difficult.

Because normal local voltage control capability was unavailable due to the remaining transmission circuit outages, a conservative approach to load restoration in this area was required, until at least a second line had been restored.

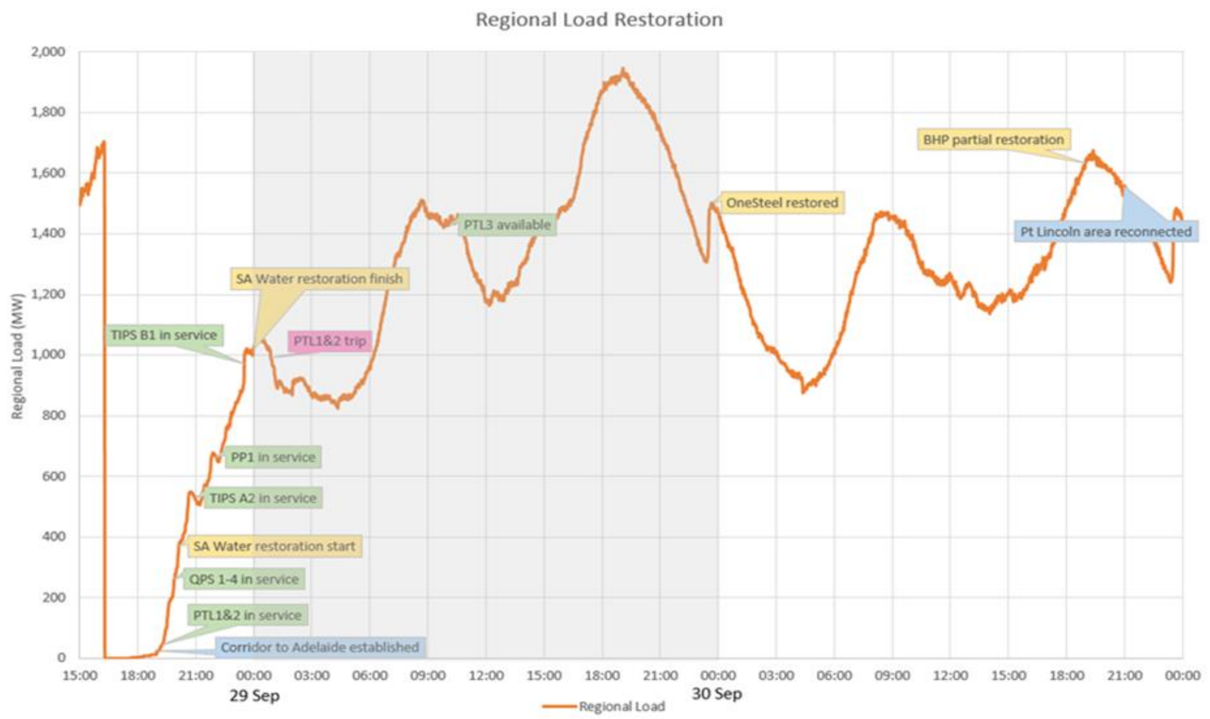
Figure 25 and Figure 26 show the restoration timelines, including events that had a material effect on restoration progress.

Figure 25 8 hours after the Black System



Load restoration continued on Thursday 29 September 2016 as transmission supply was restored to some areas in the north.

Figure 26 56 hours after the Black System



Appendix U provides an overview of the progress of load restoration in the Adelaide metropolitan area.

4.5 Information provided to Participants

AEMO is required to keep the market advised on progress of the restoration.

Appendix T.1 contains a summary of the Market Notices issued from the Black System, during the restart, up until 'Clearance to restore last load block'

AEMO also issued five media releases to ensure the market and the public were kept informed.[62]

4.6 Conclusion of the Black System

In accordance with AEMO operating procedures[63], for a Black System condition to no longer exist the following criteria must be met:

- Restoration of the power system has reached a level where all involuntary load shedding has ceased and clearance to restore the last load block has been given, and
- The emergency situation is expected to continue to improve within the part of the power system declared as a Black System.

At 1825 hrs on Thursday, 29 September 2016, AEMO considered the above criteria had been met and advised the market that the Black System condition no longer existed.

Although AEMO had given clearance to restore the last load block in SA, this does not mean all load had been restored, only that sufficient supply capacity was available to restore all load as the transmission network was restored. Some customers still remained without supply due to faults on the transmission and distribution networks.

The Market suspension in SA remained in place even though the Black System condition no longer existed. This is discussed further in Chapter 6.

4.7 Restoration performance

4.7.1 Best practice – international comparison

A review of recent Black System events, within and outside of Australia, provides a useful point of comparison. The following table highlights a number of recent events and the times it took for the system operator to restore load.

[62] Refer to Appendix T.2 for a list of these and links to the AEMO website.
[63] SO_OP 5000 – System restart Overview.

Table 14 International comparison of Black System restoration timeframes

Place	Year	Restoration time	Proportion of load restored
South Australia	2016	7.5 hours	80–90%
Turkey[a]	2015	6.5 hours	80%
Northern Territory[b]	2014	13 hours	Majority
Malaysia (Sarawak)[c]	2013	6 hours	Majority
India[d]	2012 (30 July)	7.5/13.5 hours	40/100%
	2012 (31 July)	8.5 hours	100%
Hawaii[c]	2008	15 hours	80%
Italy[c]	2003	10/15 hours	70/99%

a entsoe – Report on blackout in Turkey on 31 March 2015: https://www.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/20150921_Black_Out_Report_v10_w.pdf.

b Utilities Commission of the Northern Territory – Independent investigation into the 12 March 2014 Darwin/Katherine system black: http://www.utilicom.nt.gov.au/PMS/Publications/UC-FR-DKSB-ATTB-1403.pdf.

c International Comparison of major blackouts and restoration – AEMC Reliability Panel: http://www.aemc.gov.au/getattachment/144f4579-f61f-41ea-803f-2048e2eb695d/DGA-Consulting-International-comparison-of-major-b.aspx.

d Report on the grid disturbance on 30 July 2012 and 31 July 2012: http://www.google.com.au/url?sa=t&rct=j&q=&esrc=s&source=web&cd=9&cad=rja&uact=8&ved=0ahUKEwiLt4z10NHQAhVDu7wKHQZQA-kQFghPMAg&url=http%3A%2F%2Fwww.cercind.gov.in%2F2012%2Forders%2FFinal_Report_Grid_Disturbance.pdf&usg=AFQjCNF3n-c9iDgA_5voNkw7bIeOrQ2_Xg.

5. SYSTEM RESTART ANCILLARY SERVICES

This section reviews the performance of SRAS in SA during the Black System. Refer to Appendix P for an overview of SRAS.

AEMO has contracted with two SRAS providers in SA:

- A service provided by Quarantine Power Station (QPS).
- A service provided by Mintaro Power Station.

5.1 Performance of SRAS from QPS

Provision of SRAS from QPS is a staged process:

1. One of the smaller generating units is used to start the larger unit 5.
2. The larger generating unit is then used to energise the auxiliary supplies of other power stations in the SA power network.

The smaller generating unit is not capable of energising the transformers required to energise the 275 kV transmission network.

AEMO instructed QPS to provide a restart service at 1637 hrs on 28 September 2016.

QPS successfully started the small generating unit then attempted to start the larger generating unit. ElectraNet has informed AEMO a CB in the Torrens Island 66 kV switchyard connecting these two units was closed but subsequently tripped. Following three attempts to close this CB, the stored energy for operating the CB was depleted. This required manual intervention (ElectraNet field crew attendance) to rectify. Until this was done, power could not be supplied to start QPS unit 5.

ElectraNet subsequently advised AEMO that the CB operated correctly and the inability to close successfully was associated with a control signal from QPS unit 5.

The QPS SRAS was bid unavailable by the operator at 2200 hrs on 28 September 2016. The service was made available again by the operator from 1100 hrs on 29 September 2016, after ElectraNet staff attended the site on the morning of 29 September 2016 to reset the CB.

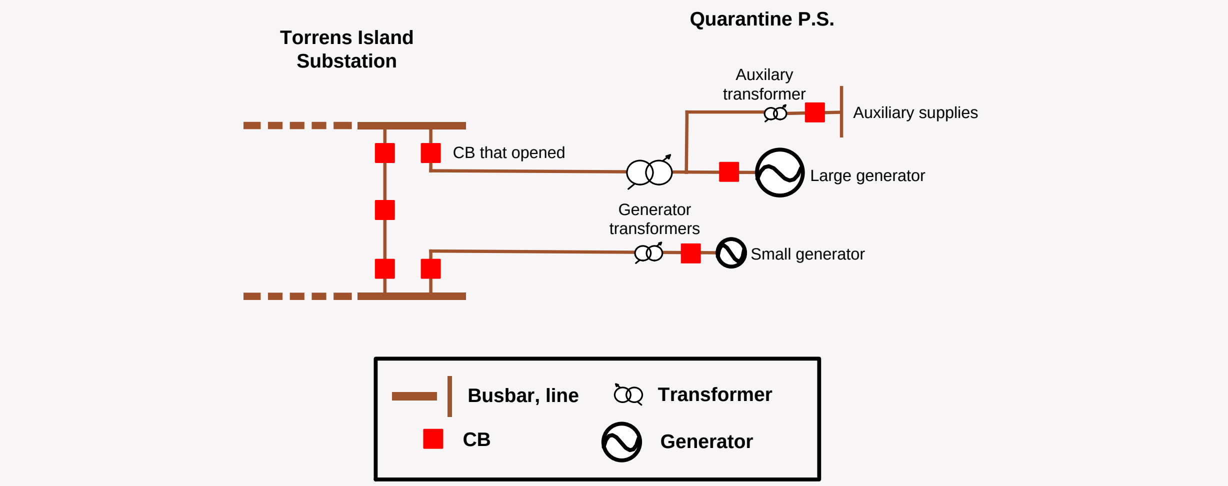
Investigation of the failure of the QPS SRAS concluded that the cause was related to the switching sequence used by ElectraNet to connect the small generating unit to the larger one.

The restart sequence carried out on 28 September had a number of steps (see Figure 27):

1. All CBs in the Torrens Island 66 kV switchyard were opened, except for the two CBs that connect the small generating unit and the large generating unit to the switchyard.
2. The smaller generating unit was then started and made fully available (spinning at full speed and generating power at nominal voltage). This energised the associated busbar at the substation.
3. The three CBs connecting the two busbars together were then closed to energise the other busbar and the generator transformer and auxiliary supply transformer of the large generating unit. When the last of these three CBs was closed, the CB connecting the large generating unit tripped.

Origin Energy has advised AEMO that the control signal that resulted in the trip of the CB on the large generating unit was the result of in-rush current on the generator transformer and auxiliary transformer.

Figure 27 Simplified schematic of QPS SRAS components



This problem had not been encountered during the test referred to in Appendix P or previous tests. Investigations by AEMO, ElectraNet, and Origin Energy have determined that a different switching sequence was used by ElectraNet on 28 September 2016 during the Black System than had been used for previous tests:

- The switching sequence used for the tests had the three CBs connecting the two busbars already closed before the small generating unit was started. In this configuration, the smaller generating unit was directly connected to the larger generating unit prior to the smaller generating unit starting. When operating in this manner, the larger unit's transformers were 'soft-started', meaning the in-rush current is gradual (as opposed to an instantaneous surge).
- The switching procedure used during the Black System connected the two generating units after the smaller generating unit was operating at nominal voltage. This essentially resulted in a large in-rush current on the larger unit's transformers.

AEMO has reviewed why different switching procedures were used.

In March 2016, AEMO received from ElectraNet a set of detailed switching procedures intended for use following a major supply disruption.[64] An updated version of these procedures was received in August 2016. One of these procedures is intended for use when SRAS is required to be delivered from QPS. This switching procedure was used by ElectraNet on 28 September 2016.

However, ElectraNet provided a different procedure for use when testing the QPS SRAS. This procedure was written on the basis that a 'soft' start on QPS unit 5 was possible and has been used for at least the last two years.

The difference in the switching sequence is subtle, and relates to how ElectraNet manages the risks associated with potential damage to a customer's plant as a result of abnormal voltages during the restart process. The switching procedure for testing manages this risk by opening an isolator, while the switching procedure used following a major supply disruption manages the risk by opening CBs. This isolator can only be operated 'dead', that is, there is no voltage on either side. While this is possible under test conditions, as the 66 kV switchyard is isolated again at the end of the test, it is not possible during an actual restart condition.

Although AEMO had a copy of both procedures, neither the Origin Energy nor the AEMO staff involved in SRAS testing were aware the procedures were subtly different.

As an interim measure, ElectraNet has agreed to use a switching procedure similar to the one used for testing to allow the smaller generating unit to soft-start the larger generating unit. AEMO witnessed a successful test using this procedure on 29 October 2016.

64 These are detailed switching procedures developed by ElectraNet in line with the requirements to convert AEMO's broad instructions, as outlined in the Regional System Restart procedures, into detailed switching sequences.

Origin Energy has reviewed its protection settings and internal processes with a view to accommodating ElectraNet's 'hard-start' switching procedure, but this has not yet been tested by AEMO.

Although QPS unit 5 could not be started, from 1713 hrs on 28 September 2016, the small generating unit was used to supply some auxiliary power to TIPS.

Power was restored to TIPS using the Heywood Interconnector at 1828 hrs on 28 September 2016.

At 1843 hrs, auxiliary supplies to TIPS A & B were swapped over from the QPS supply to the interconnection supply. Attempts to utilise the QPS SRAS were abandoned at this stage, given that QPS unit 5 could not be started until the CB in the Torrens Island switchyard was checked by ElectraNet staff.

As noted above, none of the smaller generating units at QPS is capable of energising the transformers between the 66 kV and 275 kV networks, or of restarting the larger thermal generating units on Torrens Island. It may be possible to use a number of the smaller generating units together to provide the SRAS, and this service was offered to AEMO by Origin Energy after the failure to start QPS unit 5. While AEMO considered this at the time, it was determined this was an untested process and the risks with trying to do this were unknown.

As noted in Section 4.3, the four smaller units at QPS were restarted later in the restoration process to assist in the restoration of load.

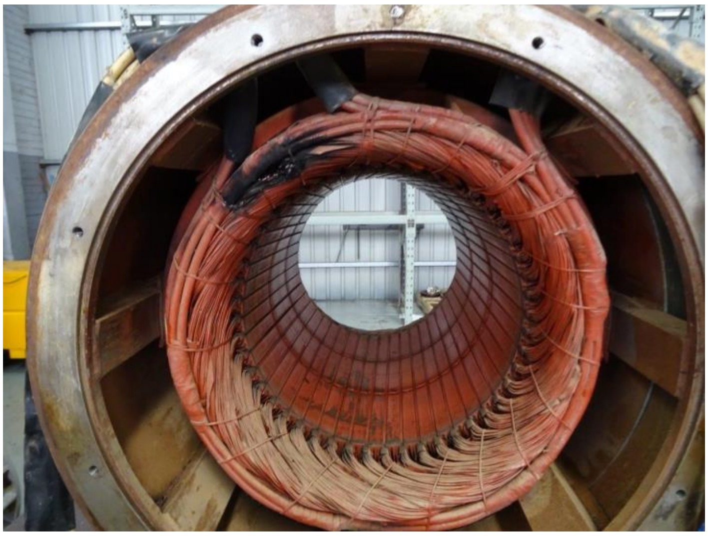
5.2 Performance of SRAS from Mintaro

Following the Black System, the Mintaro emergency diesel generator automatically started in response to the loss of supply from the network. This was in accordance with the power station's normal response to power outages, not in response to a request from AEMO. The emergency diesel generator provides power supply to all auxiliaries of the main generating unit that supplies the SRAS. The main generating unit at Mintaro cannot start without these auxiliary supplies.

Engie reported the emergency diesel generator tripped after only five seconds of operation, due to a stator earth fault which severely damaged the diesel generator (see Figure 28). This made Mintaro Power Station unavailable for service.

Multiple lightning strikes were recorded in the vicinity of Mintaro Power Station around the time of the fault, including a cloud-to-ground strike in very close proximity.[65] Although not conclusive, this is highly suggestive of lightning being the cause of the fault.

Figure 28 Damage to Mintaro diesel generator stator windings



[65] Based on information provided by Weatherzone, lightning strikes were recorded in the vicinity at 16:18:21 hrs and 16:18:29 hrs.

Engie has installed a temporary replacement diesel generator at Mintaro Power Station. AEMO witnessed a successful test of the Mintaro SRAS on 13 October 2016.

When the faulty diesel generator has been repaired and replaced, AEMO will ask Engie to conduct a further test.

The generating unit at Mintaro is not capable of restarting the large generating units in the Torrens Island area alone, due to a combination of the electrical capacity of the generating unit and the electrical distance from Torrens Island.

The only way Mintaro can be used as an SRAS is to either:

- Start the Mintaro generating unit, and use it to restart a number of smaller generating units such as Dry Creek or Quarantine unit 5, and then use this combined generation to restart the larger units, or
- Start the Mintaro generating unit, then synchronise it to the island created around QPS, and use this combined generation to assist in restarting the larger units.

As most of these smaller generating units were also unavailable, the failure of Mintaro SRAS did not in itself result in any delays to the restoration process.

6. MARKET SUSPENSION AND SUBSEQUENT OPERATION

This section outlines the market and system operation during the SA Market suspension, and subsequently to 7 December 2016.

6.1 Suspension of the market

Under clause 3.14.3 of the NER, AEMO may declare the spot market to be suspended in a region when any of the following occur:

- The power system in the region has collapsed to a Black System.
- AEMO has been directed by a participating jurisdiction to suspend the market following declaration by that jurisdiction of a state of emergency.
- AEMO determines that it has become impossible to operate the spot market in accordance with the provisions of the NER.

Following the Black System event, AEMO suspended the spot market in SA with effect from the trading interval commencing at 1600 hrs on 28 September 2016.

During Market suspension, AEMO monitors whether the cause of the suspension is continuing, and whether it can resume operation of the spot market in accordance with the NER. AEMO moves to resume the market when none of the three conditions apply and AEMO is satisfied that the possibility of suspending the spot market within the next 24 hours due to the same cause is minimal.[66]

The SA Market suspension was lifted with effect from at 2330 hrs on 11 October 2016.

6.2 Sequence of events relevant to SA Market suspension

Table 15 below describes key events relevant to the spot Market suspension in SA on 28 September 2016, including AEMO's ongoing assessment of the Market suspension criteria at each point.

At 1748 hrs on 11 October 2016, AEMO was informed that the SA jurisdictional direction was revoked. Market suspension was lifted at 2330 hrs on that day, after market participants had been provided with adequate notice and readiness to resume was confirmed.

[66] AEMO's Failure of Market or Market Systems Procedure is available at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/2016/SO_OP_3706---Failure-of-Market-or-Market-Systems.ashx.

Table 15 Market suspension review points

Timing	Review Point	Suspension Criteria			Market
		System black	Ministerial direction	Impossible to operate	
	Pre-event	-	-	-	Normal
28/09/2016 16:25	SA market suspended following the collapse of the power system in that region to a Black System.	✓	-	✓	Suspended
29/09/2016 18:25	Black System condition removed as clearance given to restore the last block of load.*	-	-	✓	Suspended**
29/09/2016 20:39	AEMO directed to suspend the market in SA by Ministerial direction under the *Essential Services Act 1981*.	-	✓	✓	Suspended
3/10/2016 23:46	AEMO reclassified the loss of a specific group of generating units in SA to be a credible contingency while investigation continues. AEMO is confident system and market can be managed through constraints and central dispatch processes.	-	✓	-	Suspended
6/10/2016 15:05	SA Government advised AEMO that the Ministerial direction to maintain suspension is extended by a further seven days.	-	✓	-	Suspended
11/10/2016 17:48	SA Government advised AEMO that the Ministerial direction to maintain suspension had been revoked.	-	-	-	Normal market resumed from 22:30

* This does not mean all load had been restored, only that sufficient generation or interconnector capacity was available to restore all load as the transmission network was restored. Some customers still remained without supply due to faults on the transmission and distribution networks.

** SO_OP_3706 stipulates the resumption of the spot market is based on the satisfying general conditions including "The original cause of the Market suspension has been eliminated or sufficient steps have been taken to exclude its influence on market processes and AEMO assesses that the possibility of suspending the spot market within next 24 hours due to the same cause is minimal". At this time AEMO did not have adequate information that the original cause had been eliminated.

6.3 Pricing under Market suspension

AEMO must determine the spot price and ancillary service prices in a suspended region, according to clause 3.14.5 of the NER. During the SA Market suspension, spot prices were determined in accordance with a pre-published 'suspension pricing schedule' of average regional prices.

Under clause 3.14.5 and associated procedures, AEMO determines a weekly suspension pricing schedule for each region on a rolling basis, published where possible 14 days before the first day to which the schedule relates. These schedules include a price for each 30-minute trading interval in the billing week, calculated as the average price in the region for each corresponding trading interval over the previous four billing weeks.

Suspension prices in one region can impact spot prices in any neighbouring regions that have a power flow towards the suspended region in any trading interval. AEMO must retrospectively calculate and apply price adjustments for those regions.

While the calculation and publication of Market suspension pricing schedules is an automated process, the subsequent application in market systems and calculation and application of price effects in other regions is performed manually. During the Market suspension, AEMO performed these calculations each business day for the previous day(s), and published the results to the AEMO website and via Market Notices.[67]

[67] Available at: http://www.aemo.com.au/Market-Notices.

The new prices were uploaded directly into AEMO's market systems and all settlement and prudential processes were then re-triggered to calculate new settlement transactions and prudential support requirements based on the revised prices.

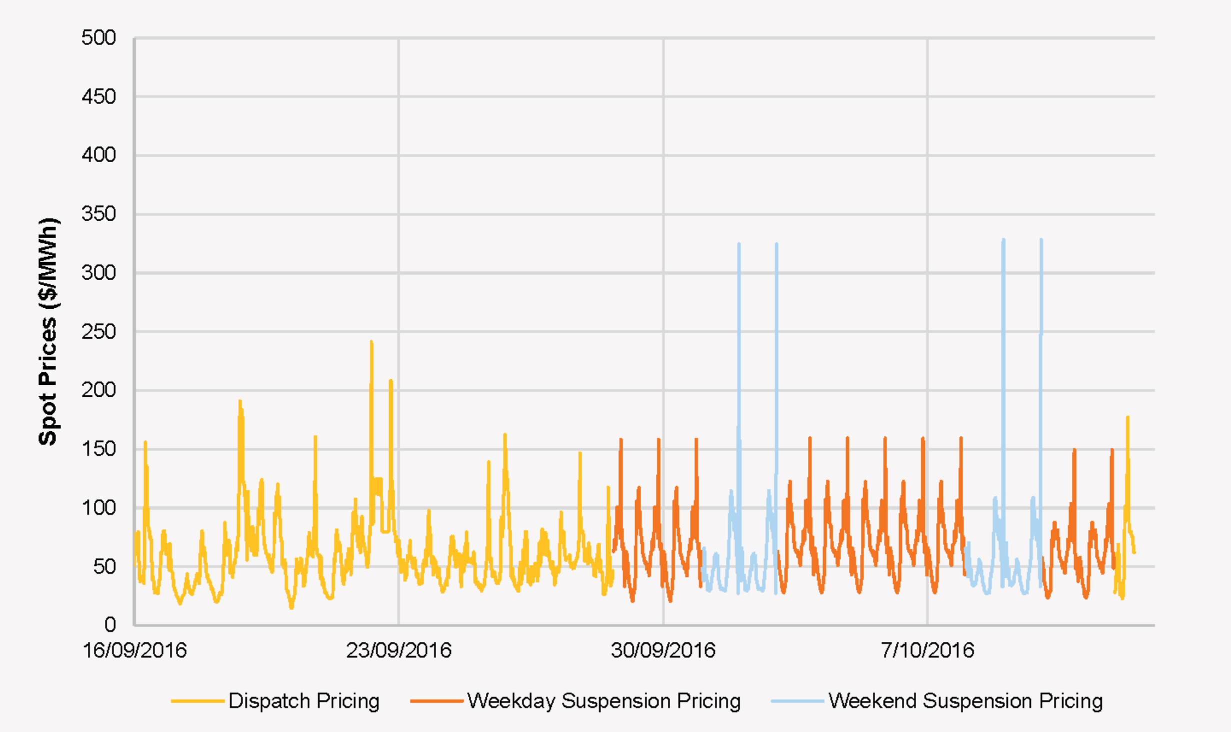
While the suspension was in effect, all normal market settlement, prudential, and compensation processes were applied using the revised market prices.

6.3.1 Spot pricing in SA during Market suspension

Figure 29 illustrates the applicable SA prices for the period 16 September to 12 October 2016, covering both normal market dispatch pricing and suspension pricing. Separate pricing schedules are calculated for weekdays and weekend days to reflect differences in typical supply and demand patterns on these days.

These prices apply to all market participants in SA, and the full schedule is provided on AEMO's website.[68]

Figure 29 30-minute spot market price in SA since 16 September 2016



Note: Price spikes on weekends reflect price spikes that occurred during the four week price-averaging period prior to Market suspension.

While these prices are not linked to the dispatch pattern of generation during the suspension, AEMO requested that Generators continue to bid their plant into AEMO's systems and follow dispatch instructions unless otherwise instructed.[69]

This ensured that, subject to system security constraints, participants in SA continued to be dispatched as close as possible to economic merit order.

6.3.2 Spot price impacts in other NEM regions

In accordance with clause 3.14.5(m) of the NER, when energy flows from other NEM regions towards a suspended region, energy prices in those regions must be capped to ensure negative settlements residue does not accrue.

Prices in those regions must not exceed the SA suspension price, scaled by the average loss factor applicable to energy flow from their region towards SA.

[68] Available at: http://aemo.com.au/Media-Centre/Prices-in-South-Australia.
[69] Market Notice 55230, issued at 1250 hrs on 5 October 2016.

During the full suspension period from 28 September to 11 October, prices were revised for 351 DIs in the Victorian region – with an average reduction of $24.51 and a maximum reduction of $267.28. For the same period, prices were capped for 33 DIs in Queensland and 37 DIs in New South Wales, with an average reduction of $13.86 and $14.23, respectively.

In accordance with clause 3.14.5(o) when determining the average loss factor applicable to determine the capped prices in other regions, AEMO must reference the inter-regional loss factor relating to the relevant regulated interconnector. Since Basslink is not a regulated interconnector, Tasmanian prices were not capped.

The table below provides price revision statistics each day during Market suspension. Full details of the price revisions are available on AEMO's website.[70]

Table 16 Price revision statistics during Market suspension

Day	# Periods Revised	Average reduction in price	Maximum reduction in price	Regions Affected
28/09/2016	3	$6.63	$10.52	VIC (3)
29/09/2016	26	$13.14	$103.68	VIC (26)
30/09/2016	29	$9.33	$144.68	VIC (29)
01/10/2016	3	$12.25	$17.64	VIC (3)
02/10/2016	1	$2.18	$2.18	VIC (1)
03/10/2016	1	$7.79	$7.79	VIC (1)
04/10/2016	15	$28.75	$88.06	VIC (13), QLD (1), NSW (1)
05/10/2016	31	$13.92	$44.93	VIC (31)
06/10/2016	32	$38.63	$87.83	VIC (32)
07/10/2016	32	$7.08	$24.74	VIC (26), QLD (2), NSW (4)
08/10/2016	198	$8.64	$30.25	VIC (136), QLD (30), NSW (32)
09/10/2016	0	-	-	-
10/10/2016	3	$8.98	$18.94	VIC (3)
11/10/2016	47	$103.05	$267.28	VIC (47)

6.3.3 Impact on settlement and prudential processes

While suspension was in effect, all normal market settlement and prudential processes continued, using the Market suspension pricing schedule and revised market prices as official price outcomes.

AEMO calculated and uploaded all revised prices into its market systems to ensure there was no impact on settlement processes. Preliminary and final settlement statements for all Market Participants will reflect the final Market suspension prices.

6.4 Directions and compensation

Between 28 September 2016 and 11 October 2016, AEMO continued to provide dispatch instructions to participants in SA, both manually and via the central dispatch system. Participants complied with these instructions and energy produced and consumed during this period will be settled in accordance with the Market suspension prices described above.

Between 28 September and 11 October 2016, AEMO issued two directions to SA Market Participants under clause 4.8.9 of the NER to maintain power system security:

- A direction was issued to the operator of a SA synchronous generating unit at 2054 hrs on 9 October 2016, instructing the station to generate at 160 MW between 0000 hrs and 0530 hrs on 10 October 2016.

[70] Available at: to http://aemo.com.au/Media-Centre/Prices-in-South-Australia.

- A direction was issued to the operator of a SA synchronous generating unit at 1616 hrs on 11 October 2016, instructing the unit to synchronise and run to minimum generation (60 MW). This direction was cancelled at 1906 hrs on 11 October 2016.

Market Participants directed under clause 4.8.9 may be entitled to compensation calculated in accordance with the NER. AEMO will publish Direction Reports following the determination of final compensation according to the Intervention Settlement Timetable.[71]

6.5 Dispatch mechanism during Market suspension

6.5.1 From 30 September 2016 until 4 October 2016

On 30 September 2016, AEMO issued an operational strategy for generation dispatch during Market suspension. This strategy set out the operational framework to manage SA's network while the market was suspended to ensure that the system remained secure and stable.

This operational strategy was developed in consultation with affected Registered Participants and included the following key points:

- All available slow start gas units would be dispatched at their minimum load.
- Any extra generation that was required in SA for this period would be met by semi-scheduled and non-scheduled wind farm generation.
- If the wind generation was inadequate to make up this difference, scheduled generation would be further utilised.

6.5.2 From 5 October 2016 until Market resumption

On 5 October, AEMO issued Market Notice 55230, notifying the market of an update to the strategy.[72] The change was intended to assist in managing power system security through the use of network constraint equations and to move towards a situation where the central dispatch system was more reflective of how the system was being operated and generation was dispatched.

Key points were:

- Where possible, dispatch instructions would be issued by the standard methods.
- Unless otherwise instructed by AEMO, all SA scheduled and semi-scheduled generators had to follow dispatch targets issued by the NEM dispatch engine (NEMDE).

6.6 Reserve management

6.6.1 From 30 September 2016 until 6 October 2016

SA contingency reserves were initially managed manually by maintaining sufficient headroom on the Heywood Interconnector to cater for the loss of the largest credible contingency event. The Victoria to SA flow was, therefore, limited to 350 MW, which was approximately the secure interconnector limit minus the largest generator, or Murraylink, if applicable, in SA.

In conjunction with the headroom on the Heywood Interconnector, the maximum single credible contingency event in SA was limited to 240 MW.

6.6.2 From 6 October 2016 until Market resumption

From 6 October 2016 until market resumption, AEMO reverted to reserve management via the normal Projected Assessment of System Adequacy (PASA) processes. As a result, the 350 MW limit on the Heywood Interconnector was lifted on this date.

[71] Intervention Settlement timetable is published on the AEMO website at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Prudentials-and-payments/Settlement-calendars/Intervention-Settlement-Timetables.

[72] As confidence increased in the NEMDE pre-dispatch and dispatch outcomes, it was decided to utilise NEMDE.

6.7 Negative settlements residue management

6.7.1 From 30 September 2016 until Market resumption

For the duration of the Market suspension, AEMO restricted the net power flow from SA to Victoria to 0 MW. This was done to minimise the market distortion in the other regions.

The following constraint equations were invoked:

- Heywood Interconnector 0 MW limit (SA to Vic). Constraint Set I-SV_000.
- Murraylink Interconnector 0 MW limit (SA to Vic). Constraint Set I-SVML_000.

6.7.2 From 4 October 2016 until Market resumption

The automatic negative settlements residue process was not producing correct results for the SA to Victoria interconnection during the Market suspension, because of the pricing mechanism applied in SA.

Consequently, the following negative settlements residue constraint equations were blocked:

- NRM_SA1_VIC1.
- NRM_VIC1_SA1.

6.7.3 From 5 October 2016 until Market resumption

Due to the dynamic nature of the power system and generation response to market dispatch targets across the NEM, it was not possible to prevent periods of power flow on the Heywood Interconnector in the direction SA to Victoria, despite a 0 MW constraint.

In response to this, AEMO developed a dynamic constraint equation to further minimise power flow from SA to Victoria:

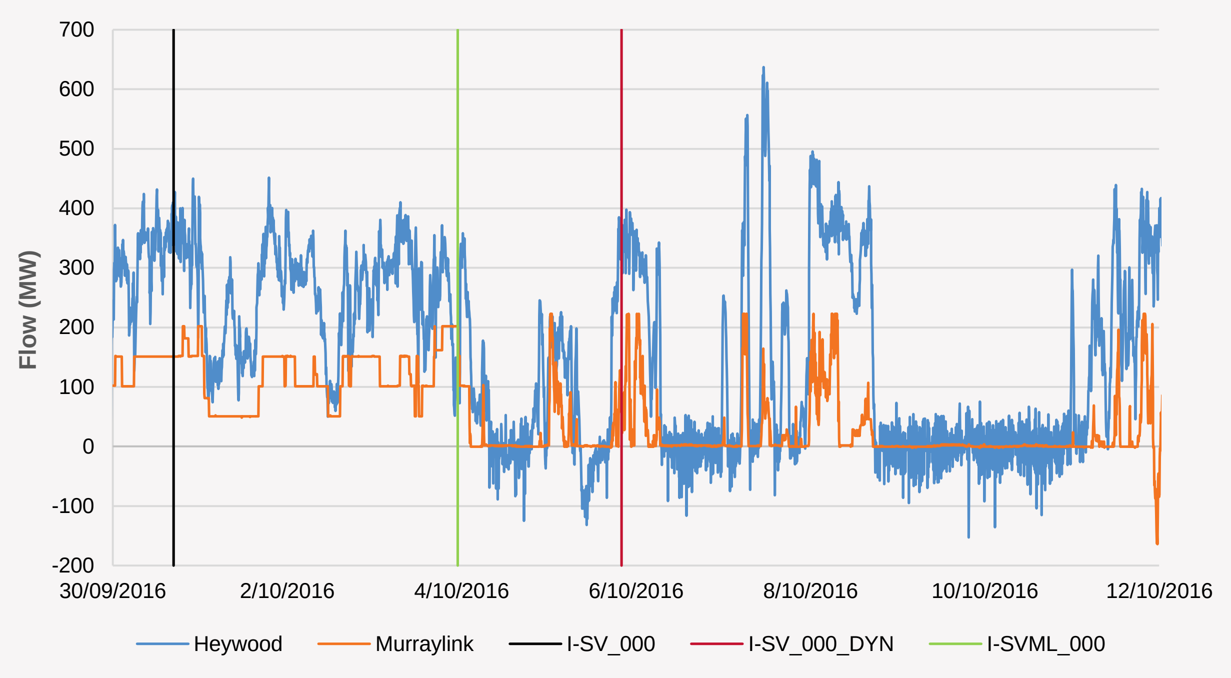
- Heywood Interconnector 0 MW limit (SA to Vic). Constraint Set I-SV_000_DYN.

This constraint equation works more effectively than the constraint equations mentioned in section 6.7.2 as it will correct the target when the actual flows on the interconnector are over the limit.

Figure 30 identifies flows on the Murraylink and Heywood interconnectors and when the following constraint sets were invoked:

- Heywood Interconnector 0 MW limit (SA to Vic). Constraint Set I-SV_000.
- Murraylink Interconnector 0 MW limit (SA to Vic). Constraint Set I-SVML_000.
- Heywood Interconnector 0 MW limit (SA to Vic). Constraint Set I-SV_000_DYN.

Figure 30 Interconnector constraint action



6.8 Power system security

The following power system security issues were identified.

6.8.1 Reclassification of wind farms

Due to the inability to determine the cause of the Black System in the short term, AEMO decided to reclassify the loss of those wind farms considered to be high risk (based on the observed behaviour on 28 September 2016) as a single credible contingency event. To facilitate this reclassification, AEMO created the following constraint set:

- S-SA_MUL_GEN_RECLASS.

At 2346 hrs on 3 October 2016, AEMO issued Market Notice 55161 announcing that the following wind farms were being reclassified as a single credible contingency:

- Bluff WF
- Clements Gap
- Mt Millar
- Hallett Hill
- Hallett
- Snowtown
- Hornsdale Wind Farm 1
- Snowtown 2 South
- Snowtown 2 North.

At 0516 hrs on 4 October 2016, AEMO issued Market Notice 55168 announcing that North Brown Hill Wind Farm was also in the initial reclassification that was announced in Market Notice 55161.

6.8.2 Changes to reclassification of wind farms

AEMO removed[73] wind farms from the reclassification after they supplied AEMO with information about taking action to ensure the cause of the generating unit trips had been addressed and AEMO had accepted the changes as adequate. AEMO also added wind farms, when it became clear, through investigation, that they were part of the credible contingency. The table below details the reclassification changes.

Table 17 Wind farm reclassification changes

Date	Action Taken	Wind farm	Market notice number
10 October 2016	Removed	Clements Gap Snowtown	55328
11 October 2016	Removed	Snowtown North Snowtown South Hornsdale	55336

Five wind farms remained in the reclassification after this amendment.

The figure below identifies the total constrained value of wind farm generation as a result of these wind farm reclassifications. This value may be the result of more than one constraint acting.

Figure 31 Reclassified wind farms – total constrained power

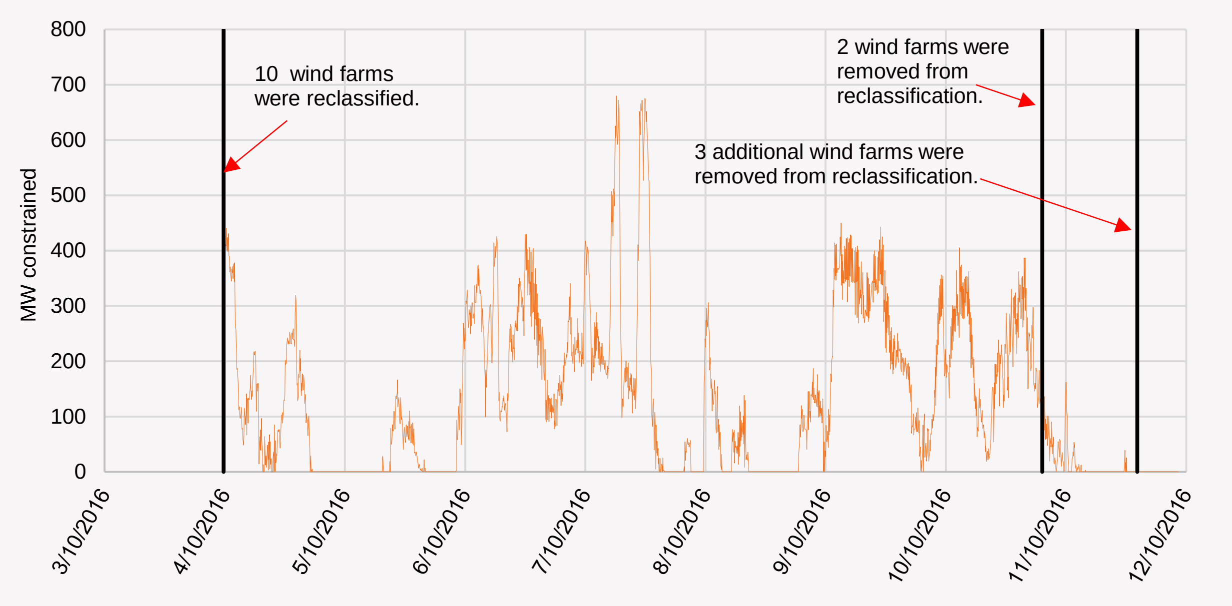


Figure 32 Minimum number of large generating units on-line

Due to the inability to determine the cause of the Black System in the short term, it was not possible to ascertain the exact generation requirement to ensure AEMO was meeting its obligations to maintain power system security.[74] However, as it was suspected that inertia and system strength may have played a role in the system collapse, AEMO determined that the level of synchronous generation on-line should not fall below the level on-line prior to the Black System.

From 3 October 2016, AEMO amended the secure technical envelope to require that a minimum of three thermal synchronous generating units, each of not less than 100 MW installed capacity, must be on-line at all times.

[73] Clause of the NER 4.2.3A (h) states "…AEMO considers that the relevant facts and circumstances have changed so that the occurrence of that credible contingency event is no longer reasonably possible".
[74] As defined in chapter 4 of the NER. During the Market suspension period the system was not insecure for longer than 30 minutes.

To maintain secure operation of the power system within the revised technical envelope, the following directions were made during the Market suspension:

- At 2054 hrs on 9 October 2016, a direction was issued to a synchronous generating unit to synchronise and ramp to minimum load by 2400hrs. The direction stayed in place until 0530 hrs on 10 October 2016.
- At 1616 hrs on 11 October 2016, a direction was issued to a synchronous generating unit to synchronise and ramp unit B2 to minimum load. The direction was cancelled at 1906 hrs on 11 October 2016 due to the impending resumption of the market.

During the suspension, the market systems continued to produce a spot price in SA, based on generator bids and offers, which was not reflective of the suspension pricing schedule.

To ensure units remained on-line, semi-scheduled generation typically bid all energy at the market price floor, whereas scheduled generation bid reflective of the suspension pricing schedule, with smaller quantities at the market price floor. As a result of tie-breaking limitations in NEMDE, units with larger quantities at the market price floor were dispatched to higher targets. This resulted in scheduled generating units being dispatched below their minimum load, even when the units were required on-line for power system security. AEMO undertook constraint action when required, such that units would not be dispatched under their operational minimum.

The table below summarises of the number of large synchronous generators on-line during the Market suspension period.

Table 18 Synchronous generating units on-line

Date	Number of large synchronous generators on-line
28-Sep-16	0
29-Sep-16	4
30-Sep-16	8
01-Oct-16	6
02-Oct-16	6
03-Oct-16	6
04-Oct-16	5
05-Oct-16	4
06-Oct-16	3
07-Oct-16	3
08-Oct-16	3
09-Oct-16	3[a]
10-Oct-16	3
11-Oct-16	3[b]
12-Oct-16	4

a At 2054 hrs a direction was issued to Pelican Point to come on-line.
b Market suspension lifted 11 November at 2230 hrs.

6.9 Frequency control ancillary services

AEMO must ensure sufficient FCAS are enabled such that the system can respond effectively to frequency deviations.[75] When all regions are synchronously connected, FCAS can be sourced from any region to meet global (NEM-wide) requirements.

No SA generating units were participating in the FCAS market prior to the event. During the event, the frequency in SA did not enter bands where FCAS response would have been triggered until after loss of the Heywood Interconnector at 16:18:15.8.

The NER does not prevent FCAS from being sourced within a suspended region, however, the provision of FCAS from a suspended region to support a global FCAS requirement is not workable with

[75] The minimum timeframe for FCAS service to act is six seconds; i.e. much longer than the quarter of a second the SA frequency took to collapse.

Market suspension pricing. In particular, the central dispatch process cannot optimise services across both suspended and unsuspended markets. Global FCAS requirements were sourced from other NEM regions during this period.

AEMO would still have sourced FCAS from registered ancillary service providers within SA if it became necessary to do so to maintain power system security or reliability.

During the Market suspension period, no local FCAS requirements arose and AEMO did not dispatch FCAS from participants in SA.

6.10 Rate of Change of Frequency

On 4 October 2016, AEMO received a ministerial direction that revised the secure technical envelope as follows:

- Rate of Change of Frequency (RoCoF) of the SA system, in relation to the non-credible contingent trip of the Heywood Interconnector, must be limited at or below 3 Hz per second.

To maintain secure operation of the power system the following constraint equations were added to the S-NIL constraint set:

- V_S_NIL_ROCOF.
- S_V_NIL_ROCOF.

These constraint equations limit flow on the Heywood Interconnector under conditions of low power system inertia in the SA system.

The table below shows the proportion of time the constraint equations V_S_NIL_ROCOF and S_V_NIL_ROCOF bound from 5 October 2016 to 14 November 2016.

Table 19 RoCoF constraint action

Constraint equation	Number of binding intervals (DIs)	Proportion of time the constraint bound (approximate)
V_S_NIL_ROCOF	2352	20%
S_V_NIL_ROCOF	68	0.6%

On 12 October 2016, regulations were made by the SA Governor[76] under which ElectraNet was required to issue limits advice to AEMO with substantially the same effect as the previous Ministerial direction. ElectraNet provided that advice to AEMO on the same date, and this replaced the Ministerial direction after the direction expired on 13 October 2016.

This RoCoF requirement remains in place.

6.11 Other issues experienced during Market suspension

The lack of detailed procedures on how to operate the power system under extended periods of Market suspension was identified as an issue. This issue particularly relates to:

- Merit order principles applicable when the dispatch engine is not usable or when directions are required.
- Management of reserves and FCAS.
- Management of export limits and negative settlement residues.
- Principles and processes for resuming market operation after suspension.

[76] *Electricity (General) (Provision of Limit Advice) Variation Regulations 2016* (SA).

6.12 Resumption of market operation

AEMO took two steps to help prepare the market for an orderly resumption of market operations:

1. On 1 October 2016, AEMO requested that Market Participants in SA continue to bid their units into AEMO's Electricity Market Management System (EMMS) as normal. This was to ensure that, subject to power system security constraints, AEMO could instruct Market Participants in a way that most closely represented economic merit order.
2. On 5 October 2016, AEMO also requested that SA market participants follow instructions being issued by its central dispatch system.

At 1748 hrs on 11 October 2016, AEMO was advised that the Ministerial direction to suspend the spot market had been lifted. At 1826 hrs, AEMO issued a Market Notice announcing that normal market operation would resume from 2230 hrs.

From 1830 hrs, AEMO performed all necessary processes to ensure that bids, forecasts, and suspension-related constraints were correctly represented in market and operational systems. Pre-dispatch systems began to publish forecasts of resumed market outcomes from 2000 hrs on 11 October 2016. At 2230 hrs spot market operation resumed in SA. AEMO continues to monitor price and dispatch outcomes closely.

6.13 Changes in current operational strategy

AEMO implemented new arrangements to maintain power system security during periods of anticipated low fault levels on 2 December 2016.[77]

[77] For further details see: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.

7. PRELIMINARY RECOMMENDATIONS

7.1 Scope of recommendations

These recommendations, arising from the third stage of the investigation of this event, focus on practical measures to:

1. Reduce the risk of islanding of the SA region.
2. Increase the likelihood, that in the event of islanding, a stable electrical island can be sustained in SA.
3. Improve performance of the system restart process.
4. Improve market and system operation processes required during periods of Market suspension.
5. Address other technical issues highlighted by this investigation.

These recommendations have taken into account

- Work already underway as part of the Future Power System Security (FPSS) Program.
- Relevant proposed Rule Changes under consideration by the AEMC.
- The 2016 *National Transmission Network Development Plan*.
- Any known proposals being made by other parties such as ElectraNet and the South Australian Jurisdiction.

These recommendations do not cover areas which are outside of the scope of responsibility of AEMO for the SA region, such as asset design and maintenance.

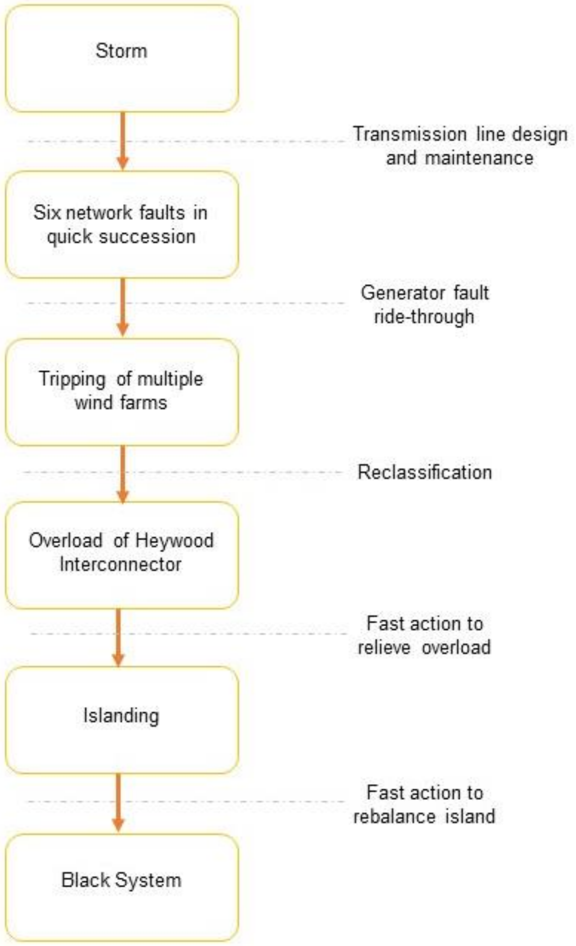
Further recommendations are expected to be made as an outcome of the final stage of the investigation, focusing on other areas including performance standards.

7.2 Pre-event and event

The focus of recommendations in this area are on measures that, if they had been in place, might have broken the chain of events which led to the Black System in the SA region on 28 September 2016.

The following diagram summarises the chain of events in a very simplified manner, and also in generic terms the type of measures that might have broken this chain of events. These type of measures are discussed after the diagram.

Figure 33 Summarised chain of events and potential mitigating measures



7.2.1 Transmission line design and maintenance

These are issues which are outside of the scope of this report.

7.2.2 Generator fault ride-through

The issues associated with compliance to generator performance standards, and recommendations in this area, are outside of the scope of this third stage of this reporting, but will be covered in the final stage.

7.2.3 Reclassification

Awareness of upgraded weather forecasts

As indicated in this report, an upgrade to the weather forecast received later in the day did not trigger a reassessment. While analysis indicates such a reassessment would have been likely to confirm the earlier assessment, the failure to undertake a reassessment has highlighted a weakness in AEMO's processes.

Recommendation 1

During extreme weather conditions, more rigorous processes to be put in place to monitor weather warnings for changes in forecasts in order to trigger reassessment of reclassification decisions where relevant.

It is planned to establish this process as soon as possible.

Reclassification due to lightning

The investigation has found that it is unlikely that the series of faults in the period leading to the Black System were caused by lightning. This is consistent with the assumption on which the current reclassification process for lightning risks is based, which is that the risk of loss of multiple circuits for high voltage transmission lines with adequate earthing protection is quite small. Thus, no recommendations have been made in this area.

Reclassification due to high winds

In the past, AEMO has only reclassified loss of multiple circuits under high wind conditions if the maximum wind speed was forecast to be in excess of the design rating for the lines as advised by the relevant TNSP.[78]

In the light of this experience and investigation, a more detailed risk-based approach should be considered, for the following reasons:

- Unlike tropical cyclones, the path and intensity of storms such as the one on 28 September 2016 are extremely difficult to forecast.
- The possible presence of tornadoes can mean that local wind conditions may be much more extreme than general forecasts suggest.
- High winds pose risks to transmission lines, not only from excessive wind loading, but also from flying debris.

Recommendation 2

AEMO to work with the PSS Working group[79] to develop a more structured process for information exchange and reclassification decisions when faced with risks due to extreme wind speeds which may include development of more sophisticated forecasting systems for extreme wind conditions including tornadoes. This proposal to then be put forward for consultation with market participants and other relevant parties such as weather service providers.

It is planned to formulate this proposal and commence consultation by end June 2017.

The event also suggested that the level of risks associated with wind turbine over-speed protection action, while not a major issue in this event, needs to be considered more closely.

[78] For instance during Cyclone Marcia in February 2015.

[79] The PSSWG is a forum for transmission System Operators to provide technical advice to the National Electricity Market Operations Committee (NEMOC) on matters that are outside the near real-time power system operations time frame, and which do not fit into the long-term planning horizon.

Recommendation 3

AEMO to assess the risks based on advice from Registered Participants on potential asset impacts, when wind speeds are forecast to exceed wind turbine over-speed cut-outs or rapid changes in wind direction are forecast in areas where there are large concentrations of wind farms and develop measures to manage this risk if it is considered material.

It is planned to complete the risk assessment by end of February 2017. Timing of development of measures will depend upon the result of this assessment.

7.2.4 Fast action to prevent separation

Because of the current difficulties in forming a stable island in SA, it would be preferable to avoid islanding if at all possible. The development of system protection schemes has now reached a level that it could be feasible to develop schemes that could:

- Detect abnormal flows on the Heywood Interconnector or events within SA that would inevitably lead to separation.
- Determine appropriate action.
- Execute this action.

However, it is yet to be determined if such schemes could be reliable and secure while still being fast enough to prevent islanding.

Recommendation 4

AEMO to investigate, in consultation with ElectraNet, the feasibility of developing a system protection scheme which in response to sudden excessive flows on the Heywood Interconnector or serious events within South Australia would initiate, if necessary, load shedding or generation tripping[80] with a response time fast enough to prevent separation.

It is planned for AEMO to assess the required performance of such a scheme by end of March 2017 before commencing investigations with ElectraNet regarding feasibility.[81]

7.2.5 Fast action to rebalance the island

If an island forms in the SA region, there is likely to be a severe unbalance between supply and demand resulting in a very high RoCoF, beyond what can be managed by the current UFLS and the over frequency management processes. There are a number of measures that could help manage this, summarised below, with recommendations where relevant.

Pre-contingent measures to restrict RoCoF

Such measures include constraining flows on the Heywood Interconnector. These have already been initiated by AEMO as short-term measures. However, these measures impact upon efficiency of the market and ideally should be replaced or supplemented by longer-term measures that do not require or reduce the need for pre-contingent arrangements.

Installation of $\Delta f/\Delta t$ UFLS relays[82]

As in Tasmania, these could be used to accelerate the tripping of the initial load blocks or generation so as to quickly reduce the RoCoF. The provision of this capability was already planned as part of the redesign of the UFLS in SA.

80 Also possible that devices such as rapid response energy storage systems could be used.

81 Implementation may also need to be supported by Rule Changes along the lines currently being considered such as the concept of "Protected Events".

82 These are relays that are triggered by rate of change of frequency rather than the value of the frequency.

Reallocation of UFLS load shed blocks

Currently, load available for load shedding is allocated to the individual blocks which are set to trigger at different frequencies to meet two requirements:

- To operate effectively when SA is islanded.
- To ensure reasonably equitable load shedding between NEM regions when there is a common frequency event.

The current design seeks to achieve a balance between these two requirements. However it is possible that the effectiveness of the UFLS under islanding could be improved (if only marginally) if the requirement for equitable sharing is relaxed to some extent.

Recommendation 5

AEMO, in consultation with the South Australian Jurisdictional System Security Coordinator, to review the allocation of load between UFLS blocks to look at possible improvements to UFLS performance under islanding conditions through some relaxation of the requirement for equitable sharing of load shedding during common NEM frequency events.

Implementation of a graded over frequency generation shedding scheme

If separation occurs while there is a significant flow on the Heywood Interconnector towards the Victoria region, there will be an initial significant over frequency in the islanding. This needs to be managed by rapid reduction or disconnection of generating units[83] within the island. This must be done in graded fashion, since over shedding of generation would then lead to under frequency conditions. AEMO has been working with ElectraNet over the past year to design such a scheme, which is now moving to implementation.

Event-triggered frequency control schemes

The development of system protection schemes is now at a level where it is feasible to take effective action immediately an islanding event is detected, rather than waiting until a significant frequency deviation is detected. Such a scheme could not be effective under all situations, so priority should be given to development of schemes to prevent islanding in the first place. Nevertheless, such a scheme would be useful in situations where a non-credible event leads to the loss of the interconnector alone.[84]

Recommendation 6

AEMO to investigate, in consultation with ElectraNet, the feasibility of developing a system protection scheme which in response to the loss of AC interconnection between South Australia and the remainder of the NEM would initiate load shedding or trip generation[85] with a response time fast enough to, where feasible, rebalance supply and demand and manage voltage changes so as to ensure a stable island (consisting of either the whole or part of the SA region) is formed.

AEMO plans to assess the required performance of such a scheme by end of March 2017 before commencing investigations with ElectraNet regarding feasibility.[86]

83 Disconnection of generating units with high inertia should be avoided.
84 For instance simultaneous loss of both circuits of the Heywood Interconnector.
85 Also possible that devices such as rapid response energy storage systems could be used.
86 Implementation may also need to be supported by Rule Changes along the lines currently being considered such as the concept of "Protected Events".

Special arrangements for frequency regulation

Even if the island is stabilised immediately, there is a need for frequency regulation services to be made available promptly. Short-term measures are being put in place to address this issue, so no recommendation is considered necessary.

In the longer term, there could be a need to encourage new types of providers of regulation services, due to the reducing availability of services from traditional sources. This issue is already part of the work of the FPSS program[87], so no recommendations have been made in this area.

Availability of FCAS to manage contingencies

Within thirty minutes of the island forming, the NER expects that there should be sufficient contingency FCAS services enabled to meet the frequency operating standard for islanded operation. It is considered that existing processes are adequate, and no recommendation for further work in this area is required.

In the longer term, there could be a need to encourage new types of providers of contingency services, due to the reducing availability of services from traditional sources. This is already part of the work of the FPSS program, so no recommendations have been made in this area.

7.2.6 Other risks

Other operational risks were identified during the investigation.

Risk of a single fault triggering low voltage fault ride-through for multiple wind farms

The events of 28 September 2016 have highlighted that a single fault in a section of the power system where there is a concentration of wind farms can reduce the voltages simultaneously at the connection points of a number of wind farms, triggering the LVRT mode of operation for all these wind farms and thus transient reductions in their outputs. In the case of SA, this would cause a transient increase in the loading on the Heywood Interconnector. The level of risk involved is unclear.

Recommendation 7

AEMO to investigate the level of risk to power system security posed by a single credible fault in an area where there is a concentration of wind farms which creates a transient reduction in output across a number of wind farms simultaneously and develop measures to manage any material risk.

It is planned to complete this work by end of February 2017.

7.3 Restoration

System restarts are rare events, so each event represents a valuable learning experience. The focus of recommendations in this area is on measures which, based on this experience, should improve the speed of restoration in a similar way without increasing risk.

[87] For more information, see http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx.

Recommendation 8

AEMO, with the SA System Restart Working Group, to review the system restart in detail to determine whether there are any:

- **Cost-effective measures which could be implemented to more quickly or effectively assess the situation immediately after a black system to determine which equipment should not be used as part of the restoration process.**
- **Cost-effective measures that could be adopted to reduce the time required to establish restart paths without increasing risk.**
- **Shortcomings in the local Black System procedures developed by Participants, and if so what measures could be taken to address any deficiencies.**
- **Cost-effective measures that could be adopted to speed the restoration of load without increasing risk including local load in remoter areas.**
- **Cost-effective measures that could be adopted to improve the communication between participants in the restart process.**

These learnings to then be shared with the Restart Working Groups in the other NEM regions, Western Australia, and the Northern Territory.

It is planned to complete this work by end of June 2017.

A major issue identified was that the operation of QPS failed due to the use of switching procedures during the actual restart that differed from the ones used to test the restart source earlier in 2016.

Recommendation 9

In preparation for an SRAS test, the test plan to be compared to the actual plan as set out in the system restart plan and associated local Black System procedures to identify and explain differences so as to ensure that the test simulates, as far as practical, the conditions that will be encountered in a real restart situation.

In the event of a material change to the equipment or procedures used in the restart of an SRAS source then AEMO, the SRAS provider and any other parties directly involved in the process to be consulted on the feasibility of the change and the annual SRAS test to be repeated to prove that this change has not impacted on the capability of this SRAS provider.

These changes are planned to be adopted immediately.

Despite a successful test earlier in the year, the Mintaro SRAS source was unavailable due to the failure of a low voltage generator. The testing of a low voltage generator alone is relatively straightforward, and is often done on a monthly basis for emergency generation for hospitals and other critical facilities.

Recommendation 10

Where the restart procedure for an SRAS source depends initially on a start of a low voltage generator, then the start of this generator alone to be tested on a regular basis, in addition to the annual test for the entire SRAS source.

AEMO plans to work with SRAS providers to put this into effect by end June 2017.

7.4 Market suspension

7.4.1 System operation

A major problem identified was the lack of detailed procedures on how to operate the power system under extended periods of Market suspension.

Recommendation 11

AEMO to develop detailed procedures on the differences required in power system operations during periods of NEM Market Suspension and identify if any rule changes are desirable in order to improve the process. **It is planned to complete this work by end of June 2017.**

There were also specific difficulties with generators receiving dispatch targets which were below the minimal stable load of their plant.

Recommendation 12

AEMO to investigate the possibility of implementing a better approach for ensuring the minimum stable load of generating units are taken into account in the NEM dispatch process. **It is planned to complete this work by end of June 2017.**

7.4.2 Market operation

The experience gained in market operations during this period has highlighted a number of opportunities for improvement, particularly relating to:

- Procedures and automation of systems for price revisions.
- Procedures for directing during suspension.
- Procedures and systems for issuing, processing and settling local FCAS requirements during Market suspension.
- Review of SRAS Recovery during a black system where there is no underlying energy to recover on.
- Review market systems handling of Market suspension flags, suspension pricing schedule, over constrained dispatch, report re-triggering, and database discrepancies.

Recommendation 13

AEMO to review market processes and systems, in collaboration with NEM participants, to identify improvements and any associated rule or procedure changes that may be necessary to implement those improvements. **It is planned to complete this work by end of June 2017.**

7.5 Data issues

AEMO's experience gathering data for the investigation of this incident has highlighted a need to improve the process.

Recommendation 14

AEMO to develop, in consultation with NEM Participants, a more structured process to source and capture data after a major event in a timely manner and better co-ordinate data requests made to Participants.

It is planned to complete this work by end of June 2017.

The availability of high speed data was invaluable in analysing this event and identifying root causes. However, correlation between high speed data from different sources was difficult at times, due to lack of a common time standard.

Recommendation 15

AEMO to investigate with NEM Participants the possibility of introducing a process to synchronise all high speed recorders to a common time standard.

It is planned to complete this investigation by end of September 2017. Further work will depend on the results of the investigation.

8. NEXT STAGE OF INVESTIGATIONS

Investigations into this event are expected to continue until March 2017, when a final report will be issued detailing AEMO's final set of findings and recommendations.

This final stage will involve investigations in the following areas:

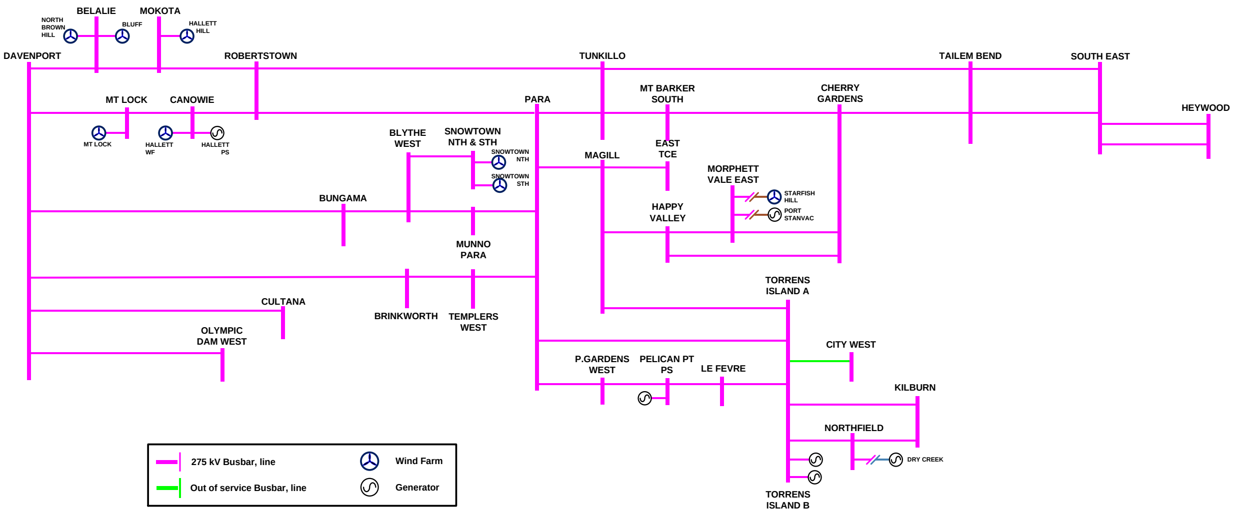
- Whether the actual performance of power system plant during the sequence of events leading to the Black System and subsequent restoration was consistent with the performance that would be expected, based on the relevant performance and system standards.[88]
- Whether changes to the access standards are desirable in light of the risks highlighted by this event.
- Analysis of any issues that arose with respect to the interpretation or application of rules or procedures during the events leading to and following the Black System and the Market suspension, and considering recommendations for change if necessary.
- Accuracy of power system models, comparing actual performance of the power system during the sequence of events leading to the Black System and its expected performance based on AEMO's dynamic power system models to confirm the accuracy of these models for this type of scenario.
- Scenario studies, including:
  - Would the result have been different if there had been 500 MW less gas-fired plant in service in SA and Northern Power Station was still in operation?
  - What would have been the result if a decision to reclassify loss of multiple transmission lines as a credible contingency had been made on that day?
- Further investigation of issues raised in this report, including:
  - As recommended in the report:
    - Performance requirements for possible special protection schemes to prevent islanding of the SA region or to improve the likelihood of such islanding being successful.
    - Level of potential risk due to transient reduction of output from multiple wind farms.
    - Level of potential risk from high winds or rapidly changing winds in in areas of high wind farm concentration.
  - Review (with ElectraNet) of:
    - The performance of SVCs at Para and SESS.
    - The risks posed by spurious impedance relay operations during such events.
    - The remaining level of risk of loss of multiple wind farms due to multiple faults on the transmission system.
    - The possibility of over voltages in the SA transmission system due to UFLS load shedding following separation from the rest of the NEM.
    - The possibility of low system strength in the SA transmission system following separation from the rest of the NEM.

[88] The AER may also be undertaking separate investigations regarding Generator compliance with their performance standards.

APPENDIX A. POWER SYSTEM DIAGRAM

This diagram illustrates the status of the SA 275 kV transmission network before the event (for clarity, lower voltage networks such as 132 kV are not illustrated).

Figure 34 Status of SA 275 kV transmission network pre-event



APPENDIX B. WEATHER EVENT REPORT SUPPLIED BY WEATHERZONE

The following is a summary of the weather event on 28 September 2016. For further details refer also to the Bureau of Meteorology's report, 'Severe thunderstorm and tornado outbreak SA 28 September 2016,' http://www.bom.gov.au/announcements/sevwx/

Synoptic Overview

An intense low pressure system brought severe weather to SA from Wednesday 28 September until early Friday 30 September, moving into Victoria and southern/south-eastern New South Wales from Thursday 20 September

The low pressure system was especially intense, with sub 974h Pa central pressure as it moved over the Bight on Wednesday 28 September. Associated with this system was a pre-frontal trough and also a cold front, both of which triggered especially severe thunderstorms as they crossed the state of SA on 28 September. This thunderstorm activity (including tornadoes) was all connected with the one synoptic scale weather system, so should be considered one event.

The complex system affected large parts of southern and south-eastern Australia, with damaging to destructive winds, widespread thunderstorms, damaging hail and heavy rainfall (leading to flooding) over SA in particular.

System progression and impacts

A strong cold front and low pressure system with significant support from a coupled upper trough lagging to the west began to move into the western parts of SA early on Wednesday 28 September 2016. As expected from a strong cold front over the region, northerly to north-westerly winds began to strengthen ahead of its passage over the western and central interior of the state, while instability over the same areas was enhanced by a weak low pressure trough extending from the interior of the country, also enhancing moisture availability for thunderstorm development.

Thunderstorms ahead of the system began to develop, spread and intensify over the southern parts of the North West Pastoral with the pre-frontal trough just before 07:00 CST, already observed as widespread over the eastern parts of the West Coast, eastern North West Pastoral and Eastern Eyre Peninsula by 09:00 CST. As storms continued to spread eastward over the peninsulas, interior and metro, the second wave of widespread thunderstorms with the frontal band began to move in over the eastern West Coast and Eyre Peninsula around 13:00 CST, also bringing sustained and damaging south-westerly winds in its wake, along the north-western flank of the deepening low pressure system. The second wave of storms led to widespread thunderstorms, likely destructive wind gusts at times, reported large and damaging hail and cloud-to-ground lightning strikes in excess of 20,000 over large parts of the Eastern Eyre Peninsula, southern Mid North, Yorke Peninsula, Adelaide, and Mt Lofty Ranges.

As the frontal band swept across the state and eventually into Victoria during Wednesday evening, the surface low pressure began to slow down significantly over the open waters to the southwest of Port Lincoln, and deepened its coupling with the upper cut-off low pressure immediately aloft. This coupling and deceleration resulted in sustained damaging winds, persistent showers and lingering thunderstorms over much of the southern and south-eastern parts of the state from midday Wednesday 28 September into the evening of Thursday 29 September.

The coupled low pressure systems slowly tracked into Victoria from late on Thursday 29 September into Friday 30 September, leading to strong and sustained south-westerly wind gusts and showers over south-eastern SA into Friday afternoon.

Major effects on South Australia

Wind

Sustained winds ahead of the cold front and low pressure system were primarily from the northwest and west, while subsequent winds were predominantly westerly to south-westerly.

Throughout the duration of the event, long periods of sustained winds of 50–70 km/h were experienced across SA, with winds progressively abating from the western interior early on Friday 30 September, but lingering over the south-eastern parts of the state into the afternoon and evening. Some parts endured sustained winds of 60–80 km/h, including the eastern parts of the West Coast, western margin of the Eyre Peninsula, Yorke Peninsula and Mt Lofty Ranges. The evening of Thursday 29 September in particular saw a spike in the sustained wind strength.

Wind gusts, notably more erratic in occurrence and frequency during intense weather systems, were significantly stronger than the reported sustained winds. Peak wind gusts on Wednesday 28 September of 90–110 km/h were reported for locations across the state, particularly when noting the wide distribution of location, including Yunta in the North East Pastoral, Snowtown in the Mid North, Cape Willoughby on Kangaroo Island, and Nullarbor on the West Coast.

Destructive wind gusts were a result of severe thunderstorms, which also carry the potential to produce tornadoes. The most likely area and time of severe thunderstorm occurrence was on Wednesday 28 September over the southern parts of the Mid North between 15:00 and 17:00 CST. It is also likely that severe thunderstorms occurred in the broad vicinity of the lower Mid North, northern Yorke Peninsula and Adelaide during or near this period.

On Thursday 29 September, wind gusts of 100–120 km/h were recorded along the eastern West Coast, Lower Eyre Peninsula, Kangaroo Island, Yorke Peninsula, and Mt Lofty Ranges throughout the day. Adelaide itself, together with large parts of all districts to the east of the Metro, reported wind gusts of 80–100 km/h throughout the day and into the early hours of Friday 30 September.

Noteworthy wind gust values include:

- Nullarbor (West Coast) – 100 km/h at 13:19 CST on 28 September;
- Snowtown (Mid North) – 104 km/h at 15:30 CST on 28 September;
- Adelaide (Outer harbour) – 96.3 km/h at 06:25 CST on 29 September;
- Neptune Island (West Coast) – 120 km/h at 12:30 CST on September 29;
- Cummins (West Coast) – 115 km/h at 03:00 CST on September 29;
- Moonta (Yorke Peninsula) – 106 km/h at 06:30 CST on September 29.

Storm surge

The sustained nature of winds that resulted from the slow-moving low pressure system, together with a large oceanic fetch, contributed to significant storm surge along coastal areas of SA on Thursday 29 September.

Hail, rainfall and flooding

The system as a whole brought 40–60 mm over large parts of southern and south-eastern Australia, exceeding 100 mm in parts of south-eastern SA and the interior of Victoria.

Large and destructive hail, together with large amounts of small hail were observed with both thunderstorm bands on Wednesday 28 September. In particular, a line of severe thunderstorms moving in a northwest-southeast line from Snowtown to Blanchtown between 15:00 and 17:00 CST would have led to large hail, damaging wind and a tornado near Blyth. More severe thunderstorms were observed to the north of this line during the same period.

Notable SA rainfall totals, rates and periods recorded are detailed below:

- Cleve – large hailstones and 14mm of rain in 15min in the early afternoon of Wednesday 28 September;

- Whyalla – 6.8mm/10min late morning on Wednesday 28 September; and
- Elizabeth and Adelaide – 9 mm in an hour late morning/early afternoon on Wednesday 28 September.

Persistent rainfall over a relatively short period of time usually leads to at least minor flooding events. As of Friday 12:00 CST, minor to major flooding was reported for the southern parts of the Mid North, Adelaide and parts of the Mt Loft Ranges.

Overview of significant warnings before and during the event

Tuesday 27 September

SA

Tue 12:09 CST – Flood Watch for Mid North, Mount Lofty Ranges and Adelaide Metro

Tue 10:20 CST – Gale Warning for Far W/Upper W/Lower W/Central/S Central coasts, Spencer Gulf and Investigator Strait. Strong Wind elsewhere

Tue 16:46 CST – Severe Weather Warning (Damaging Wind) for West Coast, North West Pastoral and Eastern Eyre Peninsula

VIC

Tue 16:49 EST – Severe Weather Warning (Damaging Wind/Heavy Rainfall) for Central, Mallee, South West, Northern Country, North Central and Wimmera

Tue 16:40 EST – Strong Wind Warning for West Coast, Central Coast, Central Gippsland Coast and East Gippsland Coast

Tue 16:40 EST – Strong Wind Warning for West Coast, Central Coast, Central Gippsland Coast and East Gippsland Coast

Wednesday 28 September

SA

Wed 10:10 CST – Severe Storm Warning (Damaging Wind) for Lower Eyre Peninsula, Eastern Eyre Peninsula, West Coast and North West Pastoral

Wed 05:29 CST – Gale Warning for Far W/Upper W/Lower W/Central/S Central/Lower SE/Upper SE coasts & Spencer Gulf. Strong Wind Warning elsewhere

Wed 12:50 CST – Severe Weather Warning (Damaging Winds) for West Coast, Eastern Eyre Peninsula and North West Pastoral

Wed 12:27 CST – Severe Storm Warning (Destructive Wind/Rain/Hail) E Eyre/Yorke Peninsulas, Flinders, Mid N & NE/NW Pastoral. Cancel W Coast & L Eyre

Wed 23:00 CST –Severe Storm Warning (Destructive Wind/Rain/Hail) Adelaide, Mt Lofty, E Eyre/Yorke Peninsulas, Flinders, Mid N, Murraylands & NW/NE Pastoral

VIC

Wed 04:55 EST – Severe Weather Warning (Damaging Wind and Heavy Rain) for the Central, Mallee, South West, Northern Country, North Central and Wimmera

Wed 11:00 EST – Severe Weather Warning (Damaging Wind/Heavy Rain) for Central, Mallee, South West, Northern Country, North Central, Wimmera and North East

Thursday 29 September

SA

Thu 13:11 CST – Severe Weather (Damaging Winds/Abnormally High Tides) for all districts excluding Upper/Lower South East

Thu 11:02 CST – Storm Force Wind for Central/S Central coasts, Spencer Gulf & Investigator Strait. Gale Warning elsewhere excl. Upper/Lower South East

NSW

Thu 13:14 EST – Gale Warning for Illawarra Coast, Batemans Coast and Eden Coast. Strong Wind Warning elsewhere

Thu 11:28 EST – Severe Weather Warning (Damaging Winds) for Hunter, Lower Western, Mid North Coast, Central/Northern Tablelands, Riverina & Upper Western

Known reported damage and effects

Damaging winds (destructive at times), heavy rainfall and damaging hail have been reported across SA. A tornado was reported in and around Blyth, coincident with the occurrence of a super-cell thunderstorms in that area, which is a necessary precursor to tornado development from thunderstorms. The reported meteorological effects led to widespread power loss for the entire state of SA, mainly due to damage to key infrastructure. Restoration was also hampered by the persistence of severe weather throughout Wednesday 28 and Thursday 29 September.

The major impact on Victoria and southern New South Wales has been rainfall leading localised to widespread flooding. This has largely been due to already saturated soils and heavily burdened rivers from above-average September rainfall.

Summary

A complex and significant cold front and low pressure system led to severe weather over large parts of SA from Wednesday 28 September to Friday 30 September 2016. Its deceleration during a key period of the passage across SA contributed to significant damage to electricity infrastructure, and loss of power to the entire state.

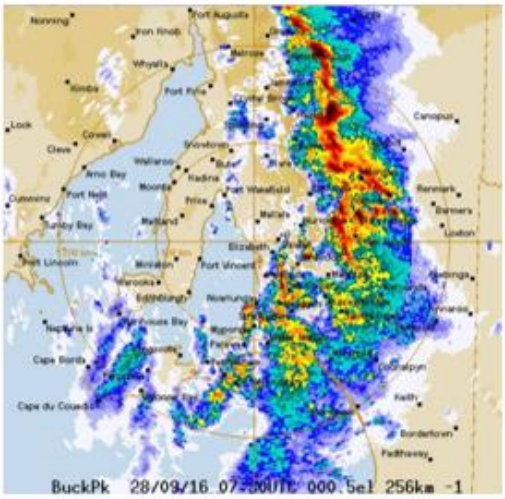
Although widespread thunderstorms affected mostly SA, the system led to significant rainfall over Victoria and southern New South Wales, where flooding subsequently continued after earlier rainfall events led to widespread flooding across these areas.

APPENDIX C. WEATHER EVENT REPORT FROM BUREAU OF METEOROLOGY

SOUTH AUSTRALIAN RAIN RADAR ON WEDNESDAY, 28 SEPTEMBER 2016

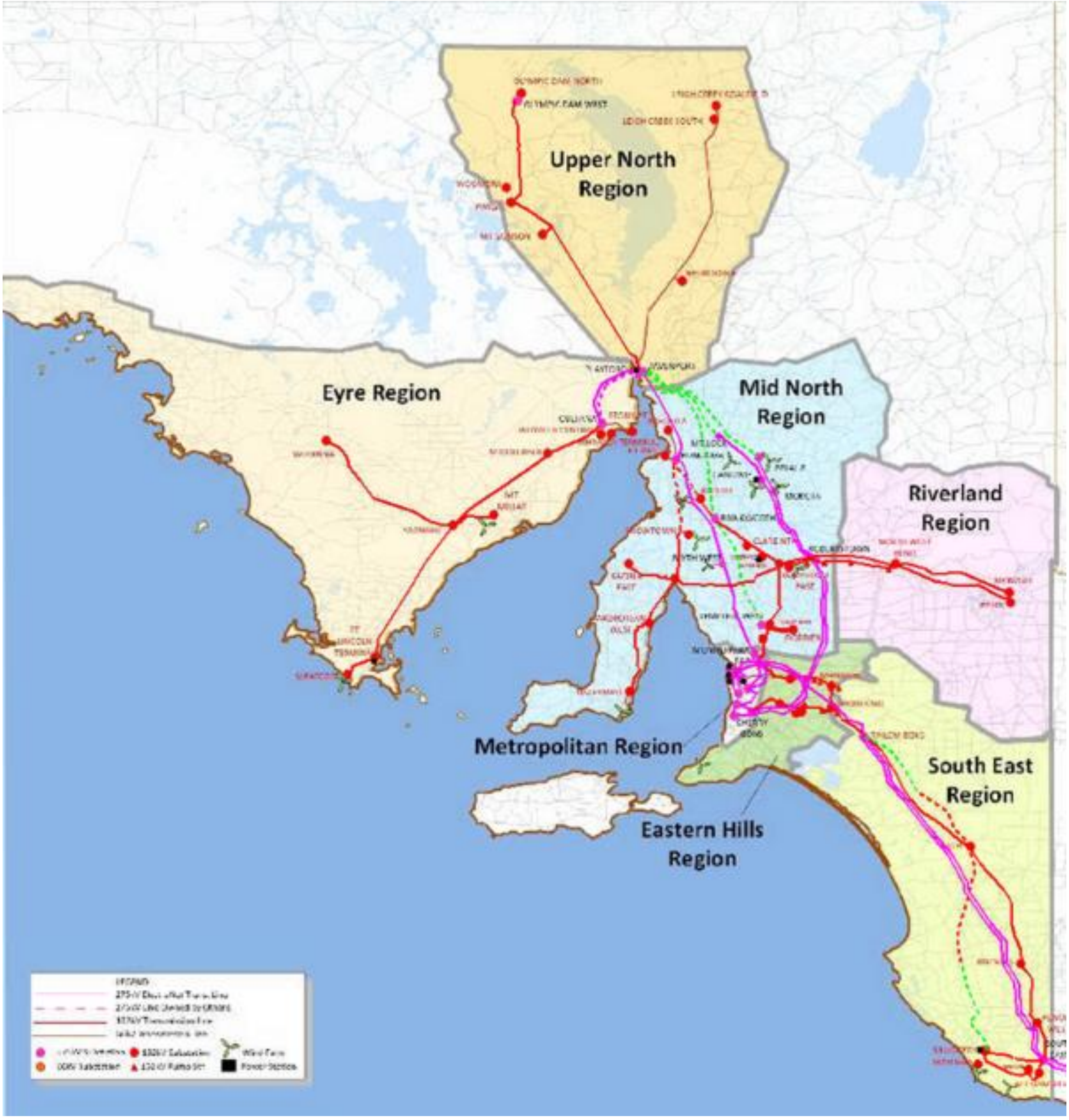
South Australia
rain radar 12 minutes after system black

South Australia
rain radar 72 minutes after system black



**The images above are from the Bureau of Meteorology.*

APPENDIX D. SA REGION TRANSMISSION SYSTEM



APPENDIX E. PRE-EVENT WEATHER INFO

E.1 Forecast weather vs actual

This table is based on Weatherzone forecast and actual data compiled by AEMO

Table 20 Summary of forecast weather warning detail and actual wind speed data

Date time of forecast for 28/09/16 (AEST)	Warning type	Forecast wind speed (km/h)	Forecast wind gust (km/h)	Issued for districts	Worst case observations for districts: wind speed (ws) and wind gusts (WG)
27/09/2016 17:16	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast North West Pastoral Parts of: Eastern Eyre Peninsula	WS: 64–76 km/h WG: 93–100 km/h
27/09/2016 20:14	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast North West Pastoral Parts of: Eastern Eyre Peninsula	WS: 64–76 km/h WG: 93–100 km/h
27/09/2016 23:00	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast Parts of: Lower Eyre Peninsula Eastern Eyre Peninsula North West Pastoral	WS: 64–76 km/h WG: 93–100 km/h
28/09/2016 02:00	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast Parts of: Lower Eyre Peninsula Eastern Eyre Peninsula North West Pastoral	WS: 64–76 km/h WG: 93–100 km/h
28/09/2016 04:32	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast Parts of: Lower Eyre Peninsula Eastern Eyre Peninsula North West Pastoral	WS: 64–76 km/h WG: 93–100 km/h
28/09/2016 07:30	Severe Weather Warning	N/A (no additional information)	N/A (no additional information)	N/A (no additional information)	N/A
28/09/2016 10:17	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast Parts of: Eastern Eyre Peninsula North West Pastoral	WS: 64–76 km/h WG: 93–100 km/h
28/09/2016 10:40	Severe Thunderstorm Warning	N/A (no additional information)	In excess of 90 km/h	Lower Eyre Peninsula Eastern Eyre Peninsula Parts of: West Coast North West Pastoral	WS: 64–76 km/h WG: 93–100 km/h
28/09/2016 12:57	Severe Thunderstorm Warning	N/A (no additional information)	Up to 140 km/h	Eastern Eyre Peninsula Flinders Parts of: Yorke Peninsula Mid North North West Pastoral North East Pastoral	WS: 64–76 km/h WG: 93–100 km/h
28/09/2016 13:20	Severe Weather Warning	50–75 km/h	90–120 km/h	West Coast Parts of: Eastern Eyre Peninsula North West Pastoral	WS: 64–76 km/h WG: 93–100 km/h

Date time of forecast for 28/09/16 (AEST)	Warning type	Forecast wind speed (km/h)	Forecast wind gust (km/h)	Issued for districts	Worst case observations for districts: wind speed (ws) and wind gusts (WG)
28/09/2016 14:40	Severe Thunderstorm Warning	N/A (no additional information)	Up to 140 km/h	Eastern Eyre Peninsula Yorke Peninsula Flinders Parts of: Mid North North West Pastoral North East Pastoral	WS: 67–93 km/h WG: 93–113 km/h
28/09/2016 15:54	Severe Thunderstorm Warning	N/A (no additional information)	Up to 90 km/h in Adelaide Metro and Mount Lofty. Up to 140 km/h in other districts.	Adelaide Metropolitan Mount Lofty Ranges Yorke Peninsula Flinders Mid North Parts of: Eastern Eyre Peninsula Murraylands North West Pastoral North East Pastoral	WS: 64–93 km/h WG: 93–113 km/h
28/09/2016 16:19	Severe Weather Warning	50–75 km/h	Up to 140 km/h	West Coast Lower Eyre Peninsula Eastern Eyre Peninsula Yorke Peninsula North West Pastoral Parts of: Adelaide Metropolitan Mount Lofty Ranges Kangaroo Island Flinders Mid North North East Pastoral	WS: 64–93 km/h WG: 93–113 km/h
28/09/2016 17:27	Severe Weather Warning	50–75 km/h	Up to 140 km/h	West Coast Lower Eyre Peninsula Eastern Eyre Peninsula Yorke Peninsula North West Pastoral Parts of: Adelaide Metropolitan Mount Lofty Ranges Kangaroo Island Flinders Mid North North East Pastoral	WS: 67–93 km/h WG: 93–113 km/h
28/09/2016 17:52	Severe Thunderstorm Warning	N/A (no additional information)	Up to 140 km/h	Flinders Riverland Parts of: Mid North North East Pastoral	WS: 70–93 km/h WG: 93–113 km/h

E.2 Additional weather data

Weatherzone provided this data (tabular format), and it has been graphed to illustrate the actual weather observations from these weather stations.

Figure 35 Snowtown weather observation (located 82km SSW of Mt Lock)

Figure 36 Port Pirie weather observation (63km west of Belalie)

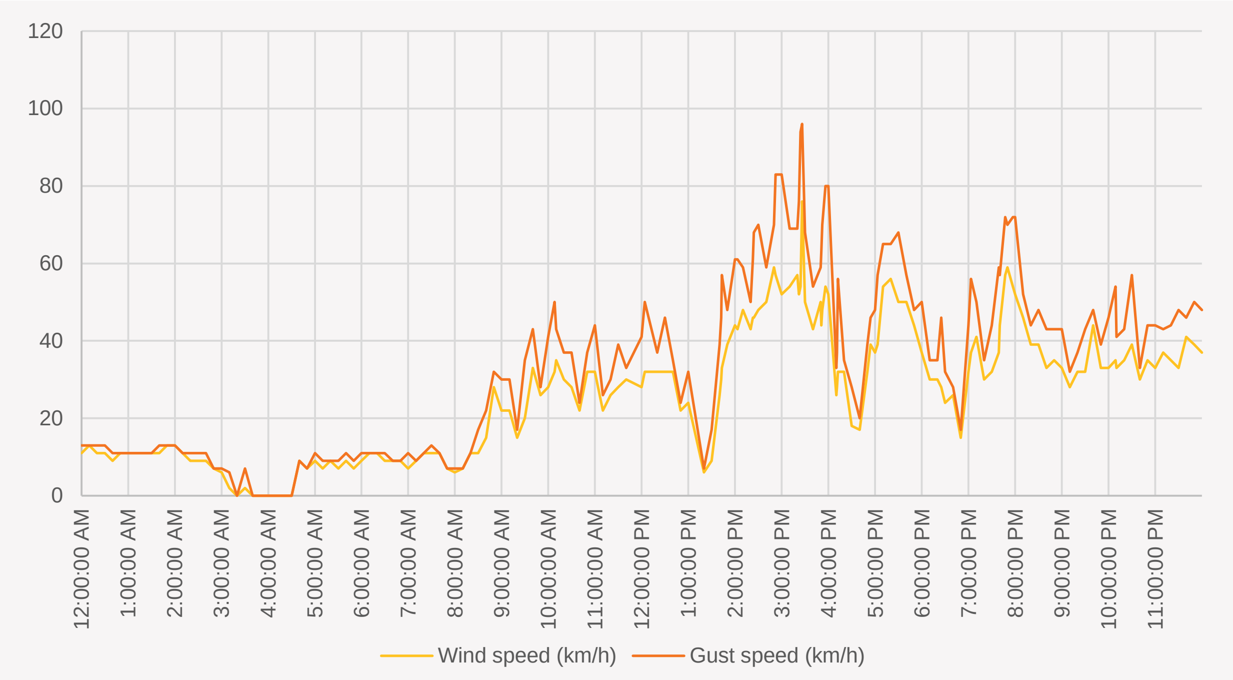


Figure 37 Port Augusta weather observation (16km west of Davenport)

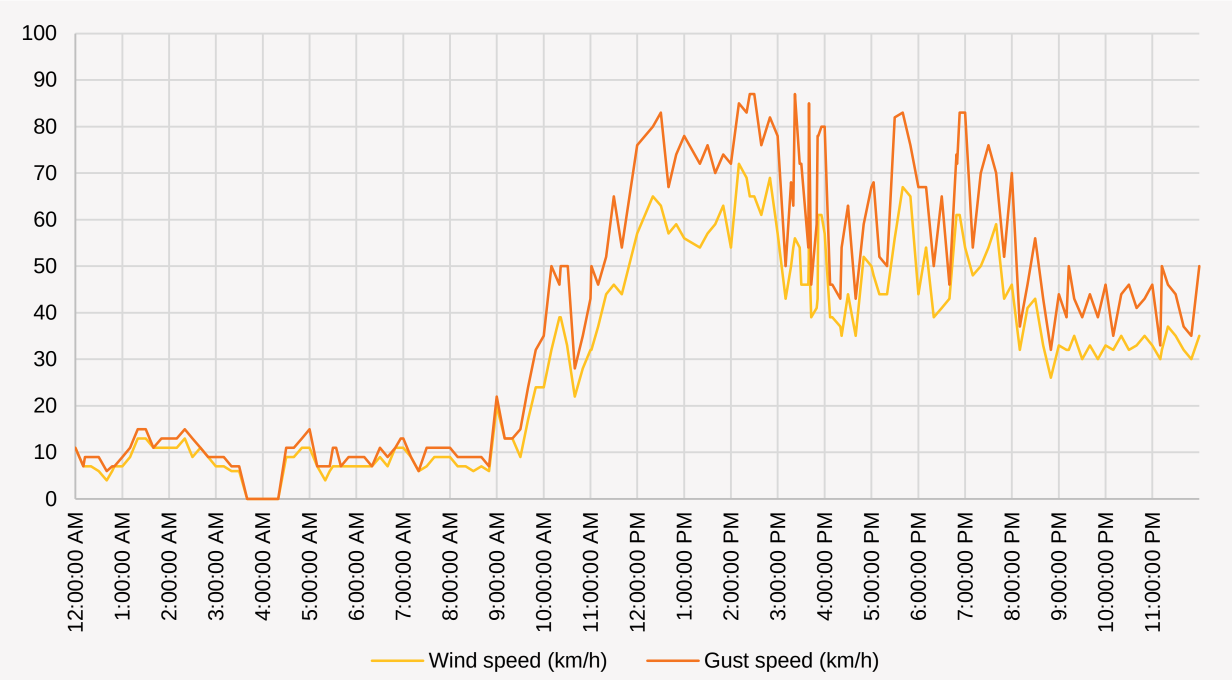
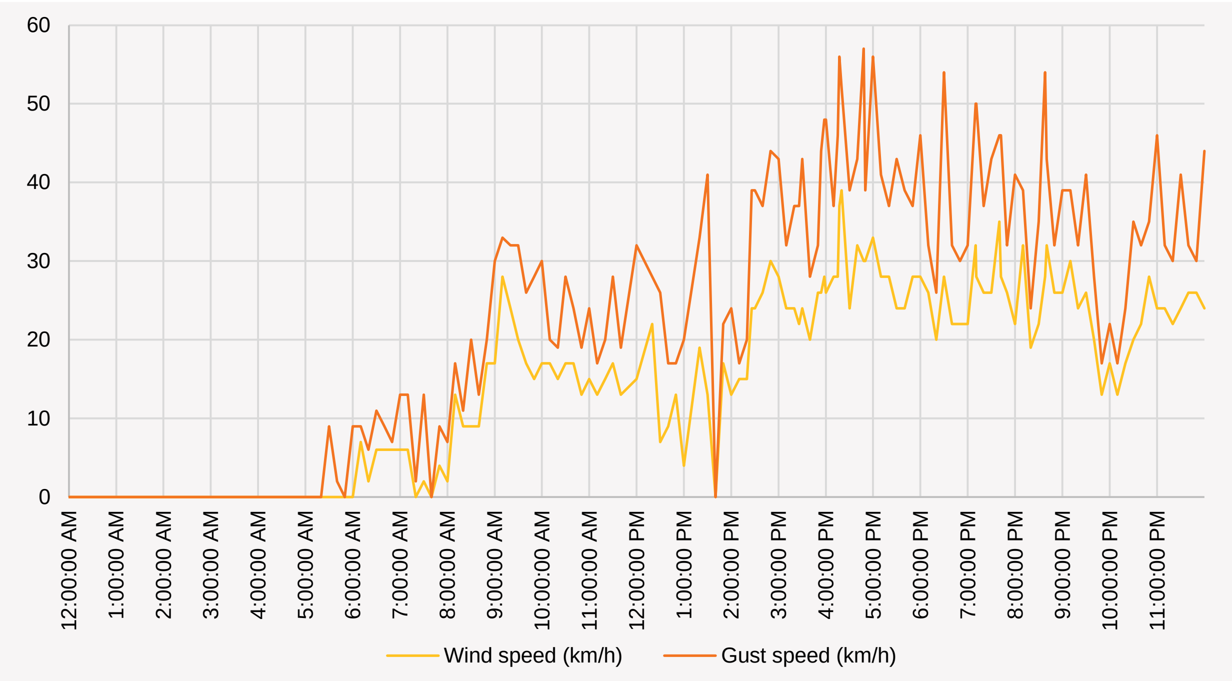
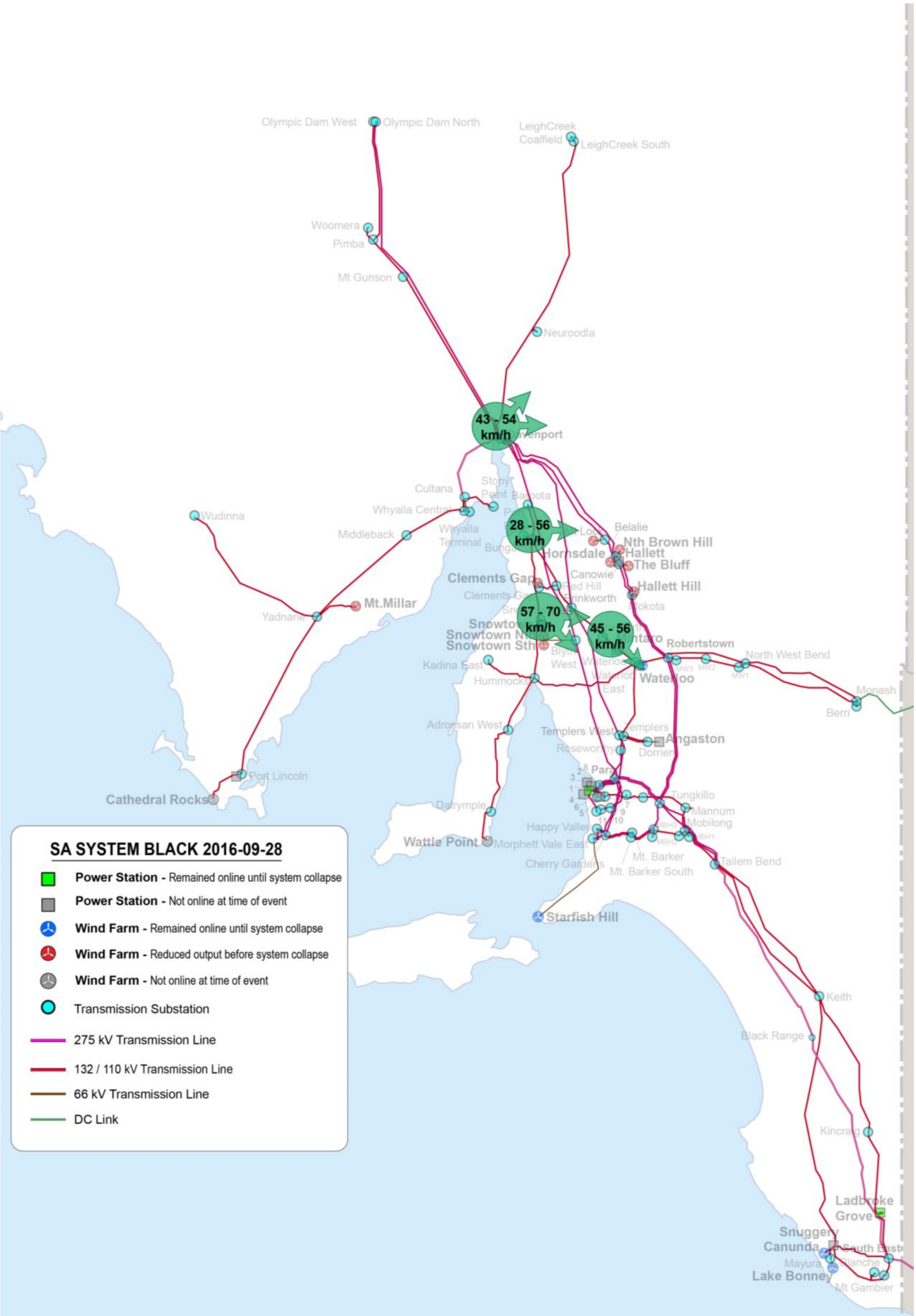


Figure 38 Clare weather observation (68km south of Belalie)



Information obtained from these four weather stations are collectively presented in Figure 39 for the five minutes period immediately before the incident.

Figure 39 Wind speed data at representitive weather stations several seconds before the blackout



E.3 Pre-event wind farm outputs

The table below details wind farms that reduced output during the pre-event timeframe.

Table 21 Table of wind farm output reductions (pre-event)

Wind farm	Initial MW	Time of reduction	MW reduction	Time to reduce MW	Recovery	'Intermittency' confirmed by wind farm data
North Brown Hill	126	14:29	91	< 5 min	Began at 14:41, stabilised at 14:52. Output ~40 MW lower.	No
Hallet	85	14:29	74	< 5 min	Began at 14:49, stabilised at 14:52 (55 MW) then 15:02. Output back to 85 MW.	No
Cathedral Rocks	21	14:33	21	< 5 min	Stayed at 0 MW.	No
Snowtown South	107	15:42	53	~ 5 min	Began at 15:49, increased ~20 MW before reducing then back to 98 MW at 16:13.	Yes
Snowtown North	141	15:44	141	< 10 min	Began at 16:07, reached 56 MW at 16:16.	Yes
Snowtown	40	15:45	32	~ 5 min	Stayed at 0 MW.	No
Clements Gap	43	15:46	41	~ 10 min	Began at 15:59, only reached 14 MW at 16:12.	No
Bluff	51	15:49	10	~ 1 min	Began at 16:06, back to 50 MW at 16:06.	No

APPENDIX F. POWER SYSTEM SECURITY MANAGEMENT

F.1 AEMO's roles and responsibilities

AEMO operates the power system in the National Electricity Market (NEM) from two control rooms in different states. These co-primary centres operate 24 hours / 365 days a year, and are equipped with identical telecommunication and information technology systems. They operate as a virtual single control room with one on-shift manager who coordinates the control room daily activities and immediate operational response to emergencies.

The NER and AEMO's operating procedures govern the operation of the NEM and the power system. Chapter 4 of the NER sets out the rules and framework that govern AEMO's responsibilities.

F.2 Preparedness

AEMO works in conjunction with Registered Participants to develop plans, where required, to cover planned and unplanned outages on the power system to an N-1 standard.[89] These plans are developed to ensure the power system is prepared for credible contingency event that would have the largest impact on the power system.[90] This may be the loss of a generator, load, or transmission element. AEMO continuously assesses the state of the power system and environmental conditions that can impact either demand or security of the network, with AEMO control rooms having a range of real-time diagnostic tools to assist with the monitoring of the power system and automatic control schemes during normal and abnormal power system conditions.

AEMO's situational awareness and response to conditions on the power system are provided through resources and processes including:

- Dedicated services providing detailed current weather conditions and forecast weather up to seven days ahead.
- Lightning and bushfire detection systems.
- Monitoring of geo-magnetic disturbance.
- Various control schemes to safeguard equipment and manage loading of equipment within ratings following contingencies.
- Established procedures specifying action when the monitored conditions change beyond acceptable thresholds.
- Dispatch of generation taking into account power transfer limits of the power system, and environmental conditions.
- Manual and automatic UFLS across the power system – up to 60% of the load supplied. This is a NER requirement to assist managing multiple or non-credible contingencies.
- Availability of under voltage load shedding at various locations, where required.
- Procurement of SRAS (see Appendix P).

F.3 Definition of a contingency event

A contingency event is defined in clause 4.2.3 (a) of the NER as an event affecting the power system which AEMO expects would be likely to involve the failure or removal from operational service of one or more generating units and/or transmission elements.

[89] N-1 redundancy is a standard of resilience that ensures system availability in the event of failure of any single transmission element, load, or generation unit.

[90] Credible contingency events are events that are considered as reasonably likely to occur in normal operation of the electricity supply system, including the trip of any single item of plant. AEMO must prepare the power system to be secure should the event occur. Non-credible contingency events are considered to be events that are less likely to occur such as the loss of a multiple items of plant at the same time – these include the loss of double circuit transmission lines or multiple generating units.

The voluntary removal from service of transmission network equipment by a Transmission Network Service Provider (TNSP) due to routine or unusual conditions is regarded as a planned or short notice outage; it is not regarded as a contingency event.

F.4 Definition of a credible contingency event

A credible contingency event is defined in clause 4.2.3 (b) of the NER as a contingency event the occurrence of which AEMO considers to be reasonably possible in the surrounding circumstances including the technical envelope. Without limitation, examples of credible contingency events are likely to include:

(1) the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating generating unit; or

(2) the unexpected disconnection of one major item of transmission plant (e.g. transmission line, transformer or reactive plant) other than as a result of a three phase electrical fault anywhere on the power system.

F.5 Definition of a non-credible contingency event

A non-credible contingency event is defined in clause 4.2.3 (e) of the NER as a contingency event other than a credible contingency event. Without limitation, examples of non-credible contingency events are likely to include:

(1) three phase electrical faults on the power system; or

(2) simultaneous disruptive events such as:

(i) multiple generating unit failures; or

(ii) double circuit transmission line failure (such as may be caused by tower collapse).

An event is credible if AEMO considers it reasonably possible in the surrounding circumstances and the technical envelope of the power system. The NER indicates that the unplanned tripping of a single generating unit or major transmission element would ordinarily be considered credible.

Events which are normally considered to be non-credible contingency events include:

- The trip of any busbar in the transmission network (these involve multiple disconnections of transmission or generation assets).
- The trip of more than one transmission element.
- The trip of transmission plant in a manner not normally considered likely (e.g. a transmission line that trips at one end only).
- The trip of multiple generating units.
- The trip of more than one load block where the combined load lost exceeds that which would normally be considered a credible contingency event in that region.
- The trip of a combination of transmission plant, scheduled generating units or load, where that combination is not normally considered likely.

F.6 Secure operating state and power system security

Secure operating state and power system security is defined in clause 4.2.4 of the NER as:

(a) The power system is defined to be in a secure operating state if, in AEMO's reasonable opinion, taking into consideration the appropriate power system security principles described in clause 4.2.6:

(1) the power system is in a satisfactory operating state; and

(2) the power system will return to a satisfactory operating state following the occurrence of any credible contingency event in accordance with the power system security standards.

(b) Without limitation, in forming the opinions described in clause 4.2.4(a), AEMO must:

(1) consider the impact of each of the potentially constrained interconnectors; and

(2) use the technical envelope as the basis of determining events considered to be credible contingency events at that time.

F.7 Satisfactory operating state

Satisfactory operating state is defined in clause 4.2.2 of the NER as:

The power system is defined as being in a satisfactory operating state when:

(a) the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band;

(b) the voltage magnitudes at all energised busbars at any switchyard or substation of the power system are within the relevant limits set by the relevant Network Service Providers in accordance with clause S5.1.4 of schedule 5.1;

(c) the current flows on all transmission lines of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;

(d) all other plant forming part of or impacting on the power system is being operated within the relevant operating ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;

(e) the configuration of the power system is such that the severity of any potential fault is within the capability of circuit breakers to disconnect the faulted circuit or equipment; and

(f) the conditions of the power system are stable in accordance with requirements designated in or under clause S5.1.8 of schedule 5.1.

F.8 Technical envelope

Technical envelope is defined in clause 4.2.5 of the NER as:

(a) The technical envelope means the technical boundary limits of the power system for achieving and maintaining the secure operating state of the power system for a given demand and power system scenario.

(b) AEMO must determine and revise the technical envelope (as may be necessary from time to time) by taking into account the prevailing power system and plant conditions as described in clause 4.2.5(c).

(c) In determining and revising the technical envelope AEMO must take into account matters such as:

- (1) AEMO's forecast of total power system load;
- (2) the provision of the applicable contingency capacity reserves;
- (3) operation within all plant capabilities of plant on the power system;
- (4) contingency capacity reserves available to handle any credible contingency event;
- (5) advised generation minimum load constraints;
- (6) constraints on transmission networks, including short term limitations;
- (7) ancillary service requirements;
- (8) [Deleted]
- (9) the existence of proposals for any major equipment or plant testing, including the checking of, or possible changes in, transmission plant availability; and
- (10) applicable performance standards.

(d) AEMO must, when determining the secure operating limits of the power system, assume that the applicable performance standards are being met, subject to:

- (1) a Registered Participant notifying AEMO, in accordance with rule 4.15(f), that a performance standard is not being met; or

(2) AEMO otherwise becoming aware that a performance standard is not being met.

F.9 Contingency management

Only credible contingency events are considered when assessing whether the system is in a secure operating state.

Contingency management refers to AEMO's operational management of the power system so that the power system remains within the pre-defined technical limits (primarily related to voltage, frequency, and asset loading) following a credible contingency.

A contingency on the power system may result in any number of abnormal conditions, some of which are listed below:

- Reduced transmission capacity between generators and load centres.
- Reduced interconnector transmission capacity.
- Separation of parts of the network into islands.
- Generation and loads relying on single connections resulting in larger than normal credible contingencies.

The majority of single contingency events are considered as being credible at all times. Some however, are defined as being credible or non-credible depending on the surrounding circumstances at the time.

F.10 Reclassifying contingency events

Reclassification of a non-credible contingency event to a credible contingency event may be necessary at times to adequately reflect current or expected conditions. Abnormal conditions may result in reclassification. The reclassification is based upon an assessed increase in the likelihood of a trip of equipment to occur, the occurrence of which is normally considered to be relatively low. If AEMO determines that the occurrence of the non-credible event is reasonably possible, based on established criteria, then AEMO must reclassify the event as credible.

The reclassification of a non-credible contingency event to a credible contingency event is to be advised to participants by the issue of a Market Notice.

Abnormal conditions are conditions posing added risks to the power system including without limitation severe weather conditions, lightning storms, and bush fires. Whenever AEMO receives information on abnormal conditions AEMO will discuss the situation with the relevant TNSP to determine whether any non-credible contingency event is more likely to occur because of the existence of the abnormal condition. If abnormal conditions exist near a regional boundary, all relevant TNSPs will be consulted.

The usual outcome of a reclassification is the introduction of a system constraint which depending on circumstances, may increase prices in one or more NEM regions.

F.11 Registered Participant, Network Service Provider, and System Operator responsibilities

In accordance with clause 4.8.1 of the NER, Registered Participants must promptly advise AEMO or a relevant 'System Operator'[91] of any circumstance that could be expected to adversely affect the secure operation of the power system or any equipment owned or under the control of the Registered Participant.

A System Operator must, to the extent it is aware, keep AEMO fully and timely informed as to:

- The state of the security of that part of the power system under its control.
- Any present or anticipated risks to power system security, such as bushfires.

[91] Generally, a TNSP to whom AEMO has delegated some of its power system security responsibilities under clause 4.3.3 of the NER. In this instance, ElectraNet is the System Operator for SA.

Clause 4.8.1 of the NER – extract[92]

4.8.1 Registered Participants' advice

A *Registered Participant* must promptly advise *AEMO* or a relevant *System Operator* at the time that the *Registered Participant* becomes aware, of any circumstance which could be expected to adversely affect the secure operation of the *power system* or any equipment owned or under the control of the *Registered Participant* or a *Network Service Provider*.

F.12 Reclassifying contingency events due to lightning

Reclassification of a non-credible contingency event to a credible contingency event could be necessary at times to reflect current or expected conditions, known as 'abnormal conditions'. AEMO's Power System Security Guidelines[93] detail the process undertaken by AEMO, and criteria used when assessing whether such a reclassification is warranted. If AEMO determines that the occurrence of the non-credible contingency event is reasonably possible, AEMO will reclassify the event as a credible contingency event.

Lightning causing the trip of two adjacent single circuit transmission lines is considered to be highly unlikely and is generally not taken into consideration for reclassification.

F.12.1 Vulnerable transmission lines

Lightning in the vicinity of a double circuit transmission line that is considered 'vulnerable' means that the event is eligible to be reclassified as a credible contingency event during a lightning storm if a cloud to ground lightning strike is detected within a specified distance of the relevant line.

The criteria used to determine whether a line should be classified as 'vulnerable' include whether the line has tripped due to lightning in the last three years and where the TNSP has advised AEMO that the line has deteriorated to such an extent that warrants reclassification.[94] These classifications are reviewed every two years.[95] In general, the higher the operating voltage of a transmission line, the less it is likely to be affected by lightning.

F.13 Reclassification due to "other" threats

Reclassification due to 'other' threats[96] may include but is not limited to the following:

- Multiple generating unit disconnection.
- Impact of pollution on transmission line insulators.
- Impact of Protection or Control Systems Malfunction.

In all such cases (that is, for threats other than Lightning, Bushfires, and Geomagnetic Induced Currents (GICs)), AEMO relies on advice from the asset owner regarding increased risks to their plant due to abnormal conditions.

F.14 Black System

Black System is defined in the NER (Section 10 Glossary) as:

- The absence of *voltage* on all or a significant part of the *transmission system* or within a *region* during a *major supply disruption* affecting a significant number of customers.

[92] Based on NER version 85, http://www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules.
[93] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.
[94] See section 11.4 of AEMO's Power System Security Guidelines for further information, available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.
[95] See section 11.4.7 of AEMO's Power System Security Guidelines.
[96] In accordance with NER 4.8.1

APPENDIX G. SA SYSTEM VOLTAGES

Figure 40 Voltages measured at Davenport – Olympic Dam 275 kV line

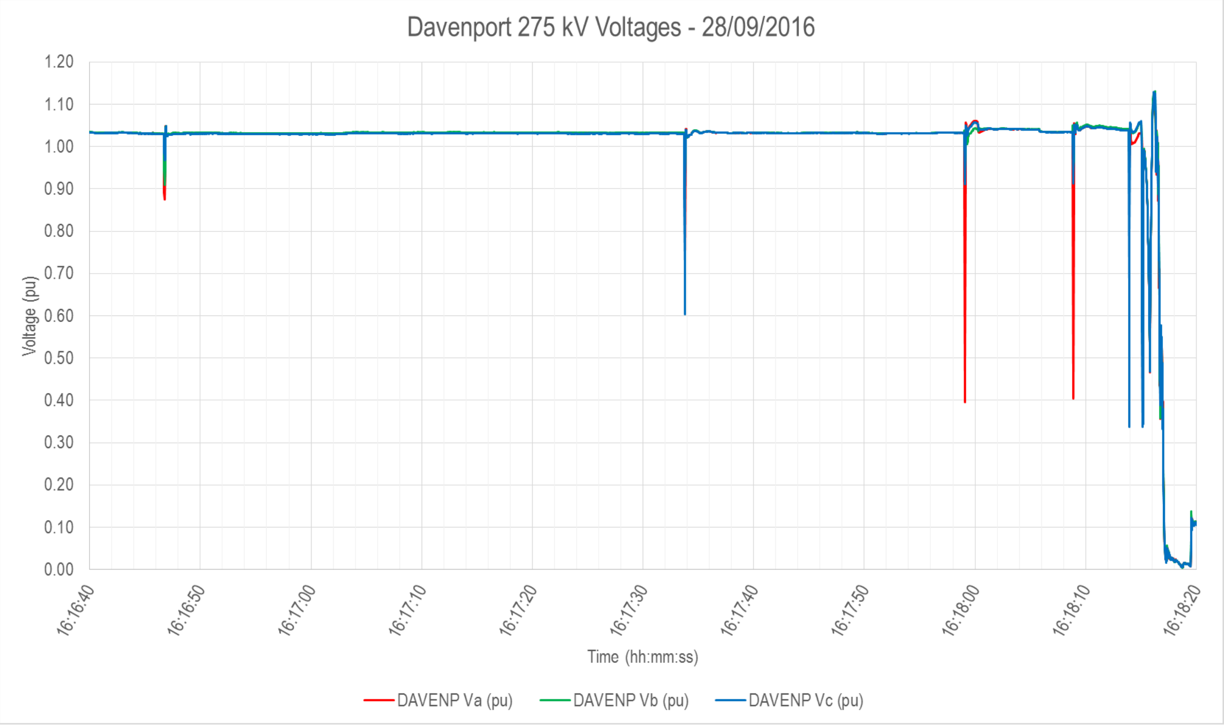


Figure 41 Voltages measured at Robertstown – Tungkillo 275 kV line

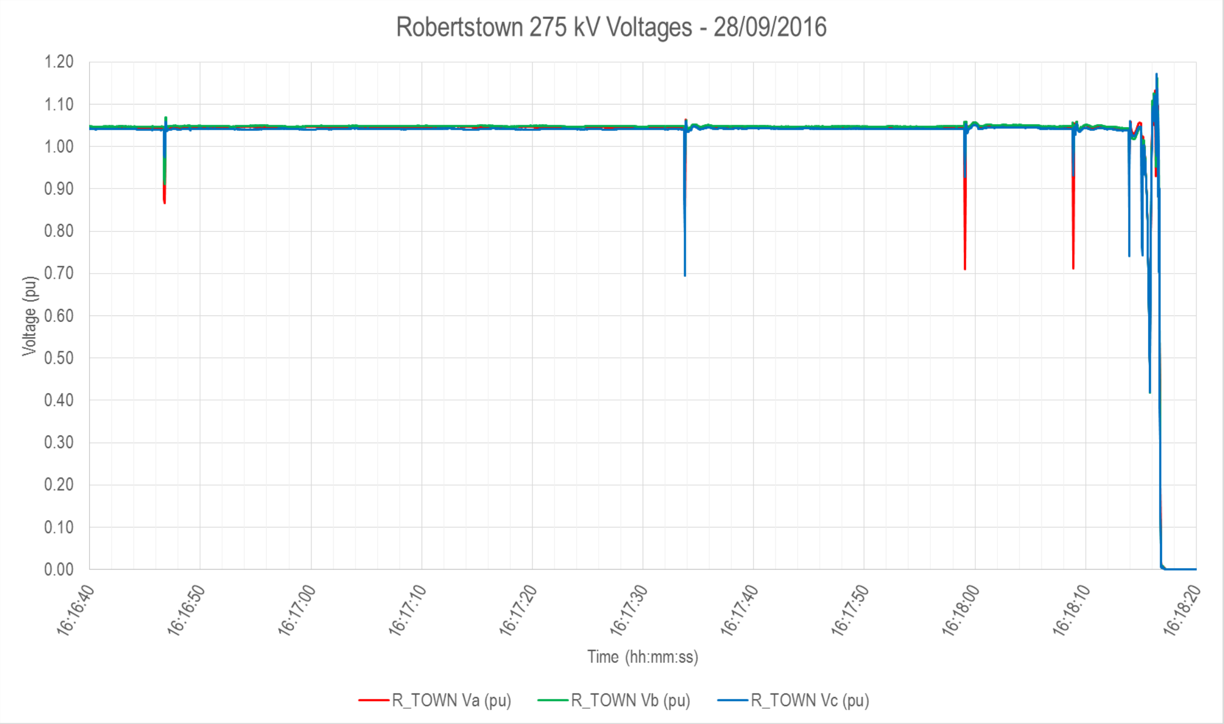


Figure 42 Voltages measured at Para – Parafield Gardens West 275 kV line

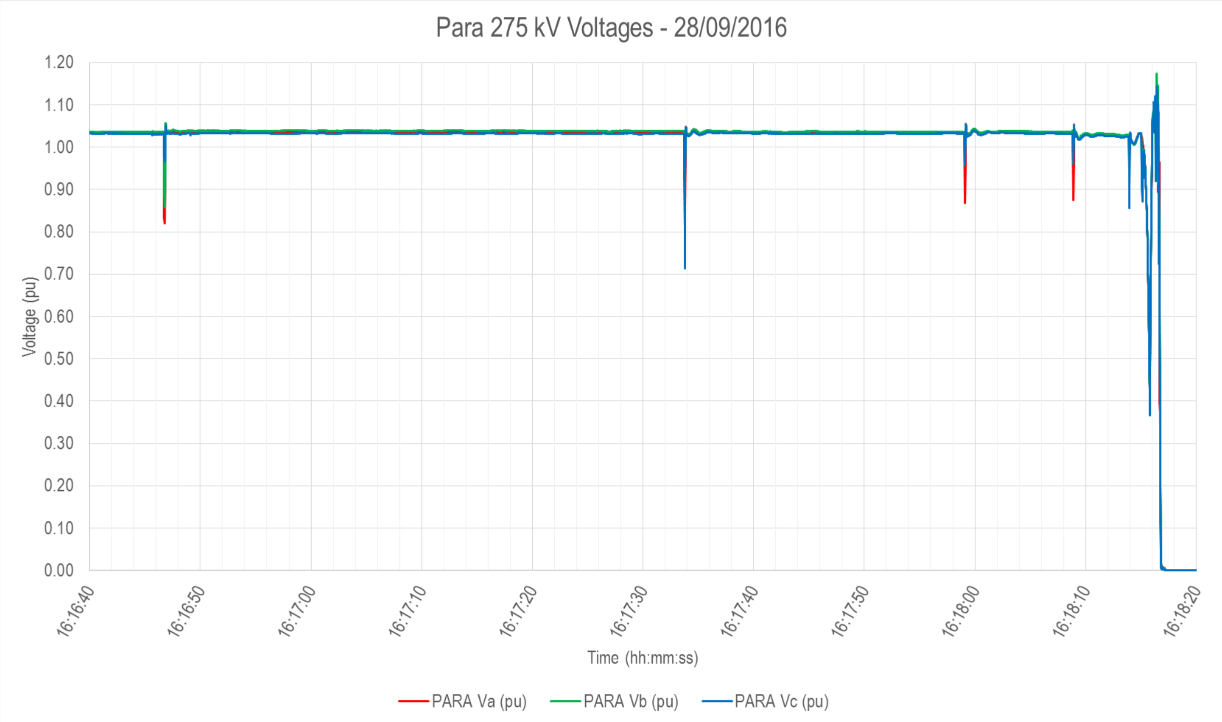
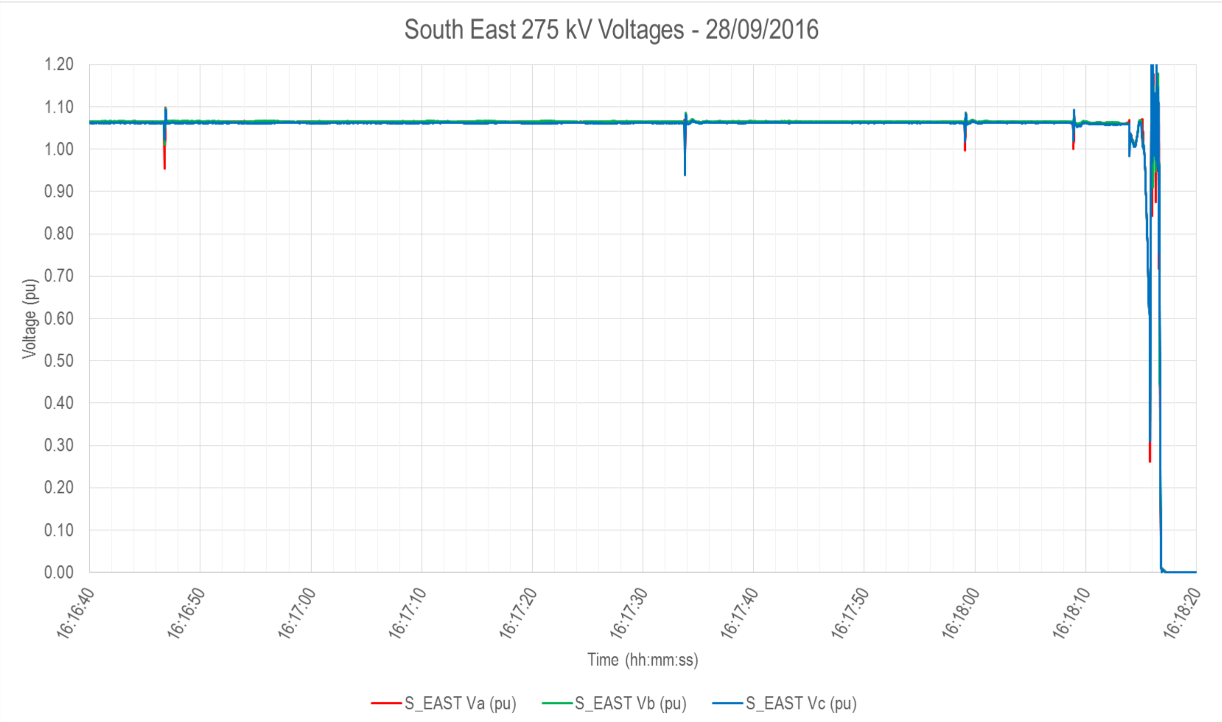


Figure 43 Voltages measured at South East – Tailem Bend No. 1 275 kV line



APPENDIX H. GENERATOR PERFORMANCE STANDARD REQUIREMENTS FOR FAULT RIDE-THROUGH

Performance standards requirements for fault ride-through are defined under clause S5.2.5.5 of the NER (Generating system response following contingency events). There is some inter-relation with clause S5.2.5.4 (Generating system response to voltage disturbance).

In SA, there are also some special licencing conditions applied by Essential Services Commission of SA (ESCOSA) that define the required performance level in relation to fault ride-through capability. AEMO assists ESCOSA in confirming that a generating system will meet its special licence conditions.

Under the NER AEMO has an advisory role[97] in negotiating particular clauses of generator performance standards. AEMO assesses proposed performance standards and works with the applicant and connecting network service provider to ensure that the agreed performance standard is consistent with the NER and meets the system requirements.

A criteria for eligibility for registration as a Generator under Chapter 2 of the NER is for a Generator to satisfy AEMO that each generating system is capable of meeting or exceeding its performance standards. To aid this exercise, AEMO regularly conducts due diligence reviews of an applicant's technical studies relating to connection and negotiation of performance standards.

AEMO also reviews test results following commissioning of new generating systems to ensure that performance standards compliance is demonstrated.

Performance standards are negotiated at a level between automatic standard and minimum standard. The standards for fault ride-through have developed over time, the most significant change between versions 12 and 13 of the NER.[98] Today, in SA, a fault ride-through standard negotiated under S5.2.5.5 of the NER requires that a generating system maintains continuous uninterrupted operation for the range of faults and protection clearance times described under the automatic standard for S5.2.5.5.

[97] AEMO has an additional function in Victoria as the transmission network service provider (TNSP).
[98] Version 13 of the NER was effective on 31 May 2007.

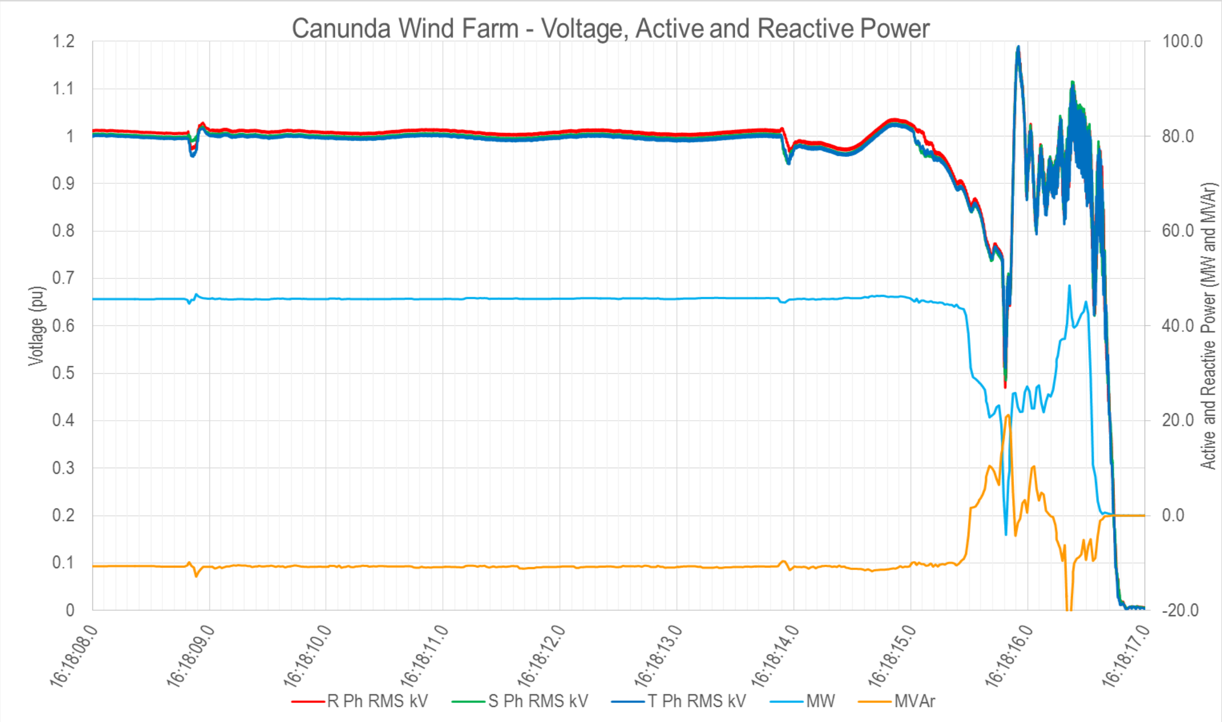
APPENDIX I.INDIVIDUAL GENERATOR RESPONSES

This Appendix discusses response of all on-line wind farms and synchronous generators between 16:18:08 and 16:18:18 on 28 September 2016.

I.1 Individual wind farm responses

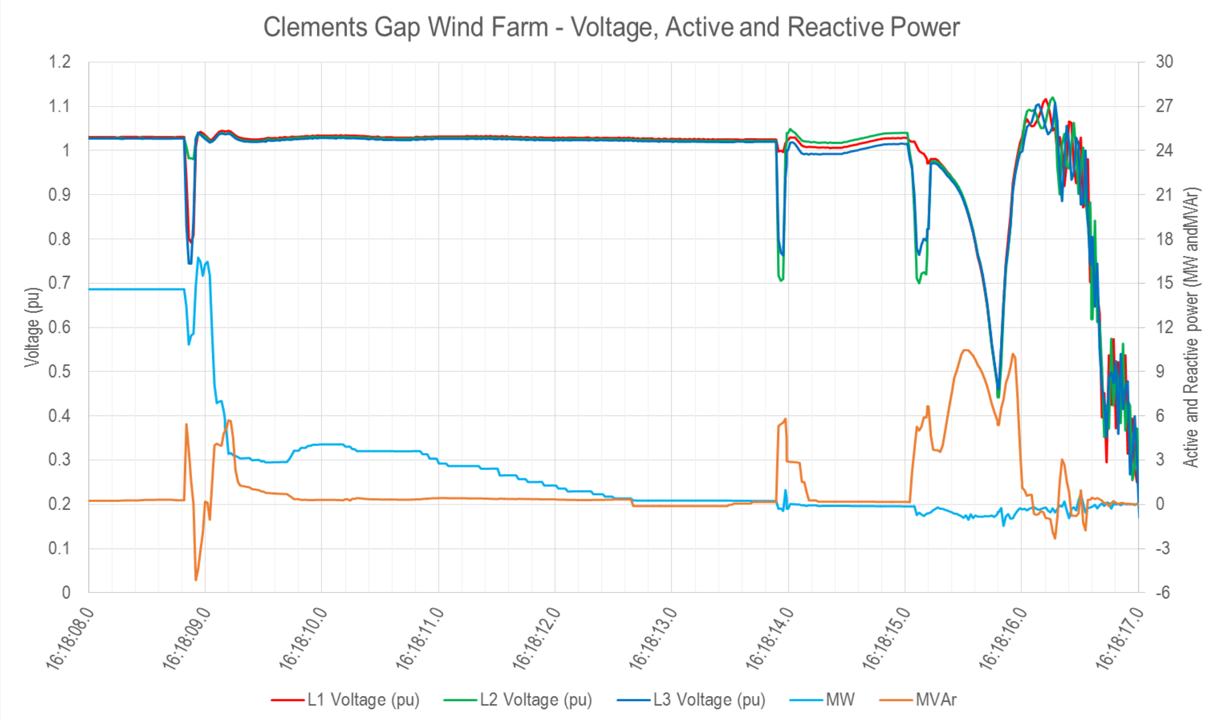
I.1.1 Canunda Wind Farm

Figure 44 Three-phase voltages, active and reactive power at Canunda Wind Farm's connection point



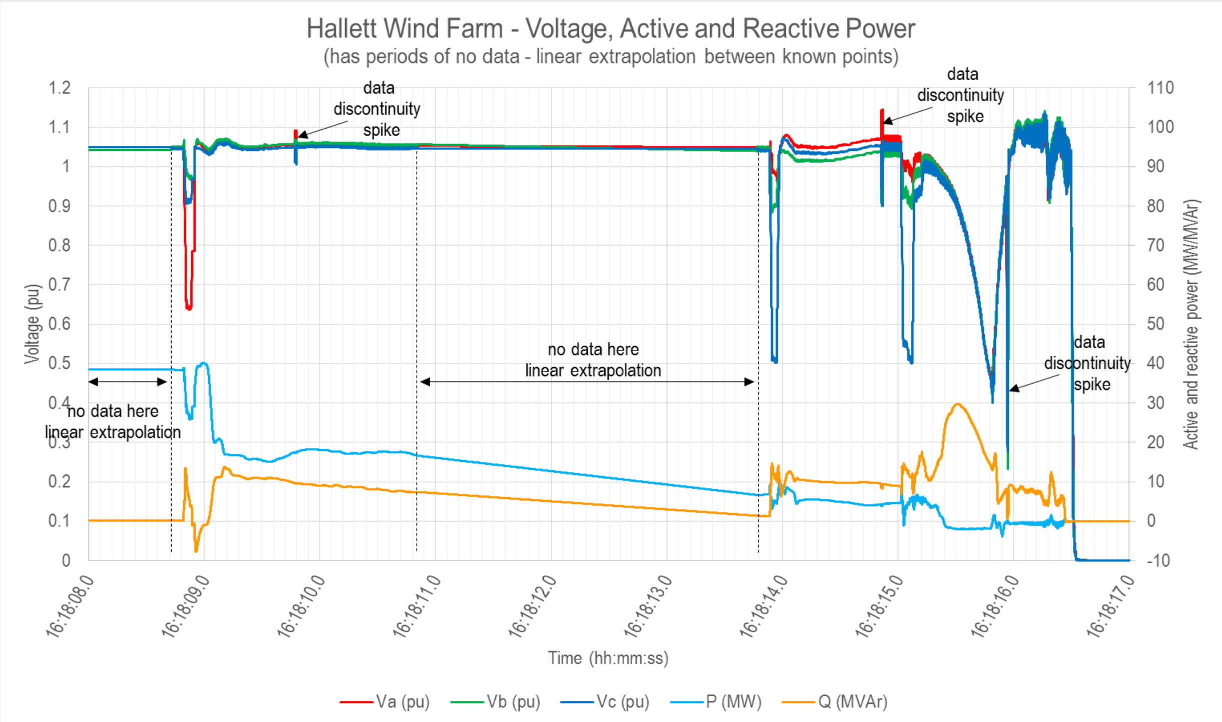
I.1.2 Clements Gap Wind Farm

Figure 45 Three-phase voltages, active and reactive power at Clements Gap Wind Farm's connection point



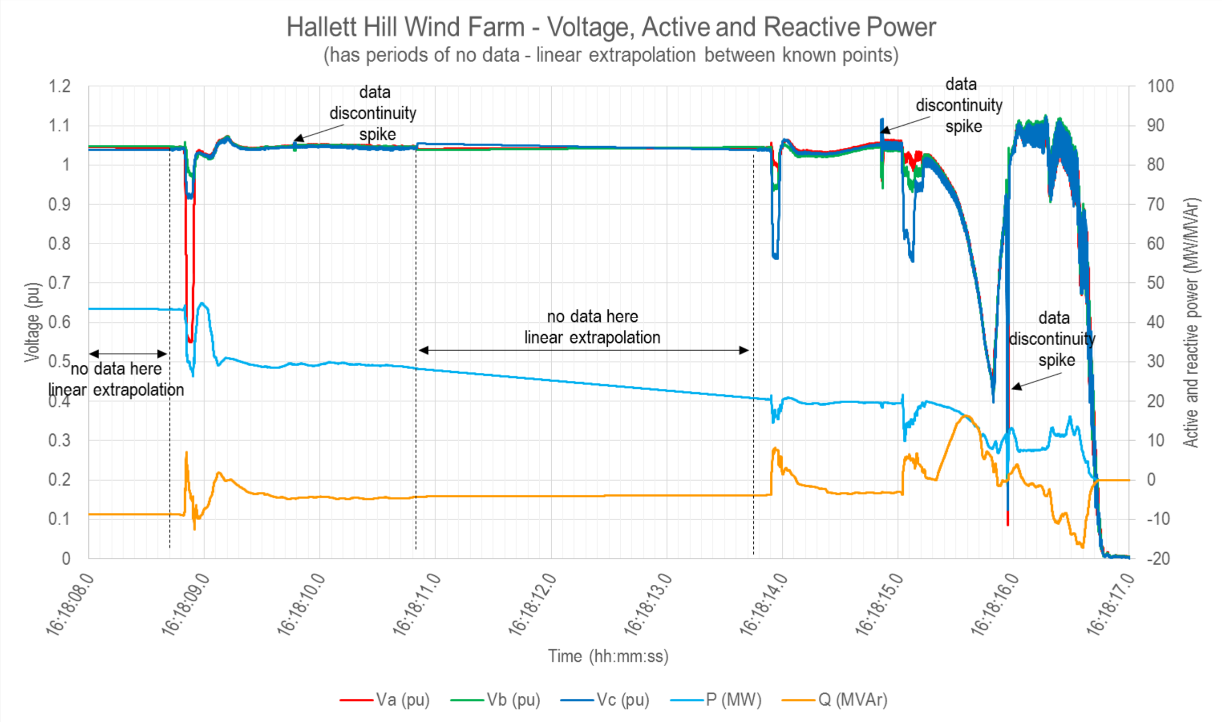
I.1.3 Hallett Wind Farm

Figure 46 Three-phase voltages, active and reactive power at Hallett Wind Farm's connection point



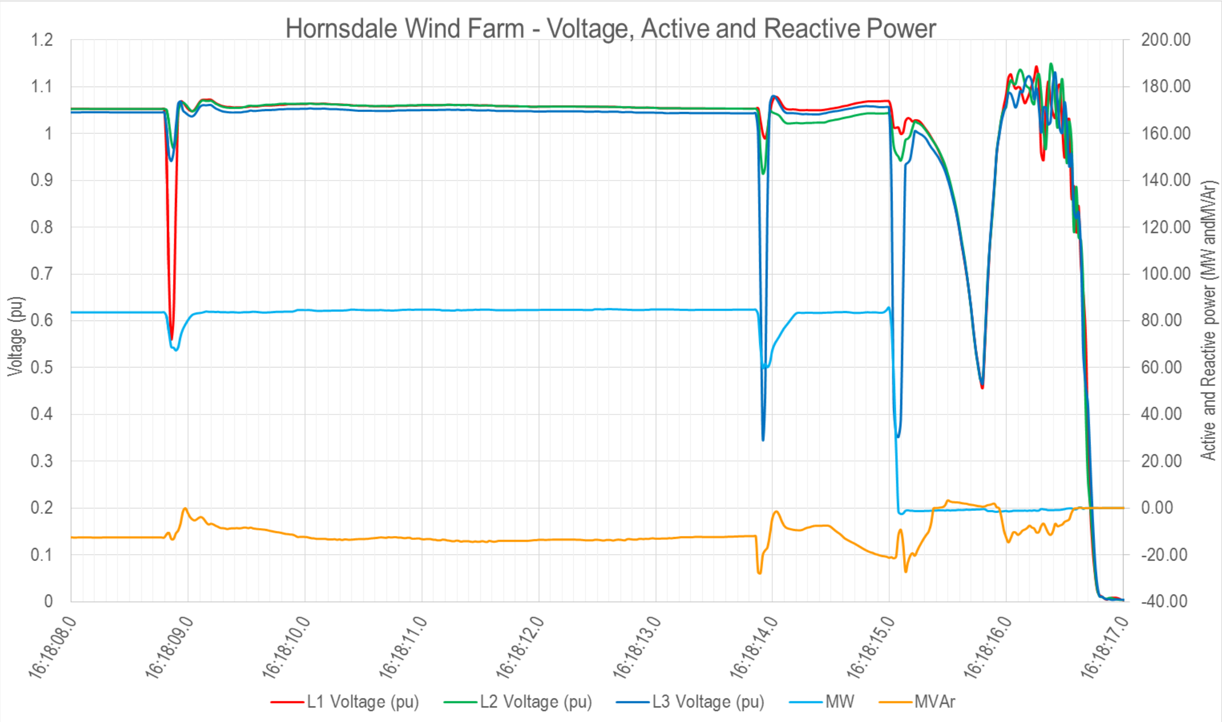
I.1.4 Hallett Hill Wind Farm

Figure 47 Three-phase voltages, active and reactive power at Hallett Hill Wind Farm's connection point



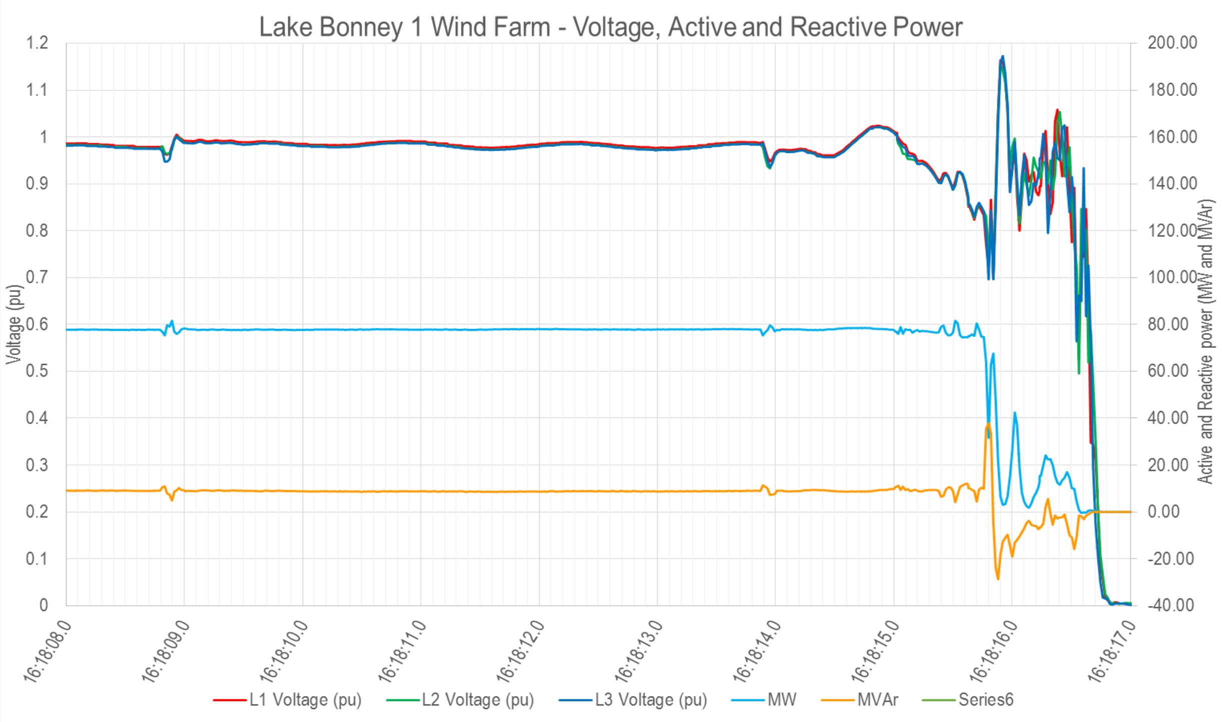
I.1.5 Hornsdale Wind Farm

Figure 48 Three-phase voltages, active and reactive power at Hornsdale Wind Farm's connection point



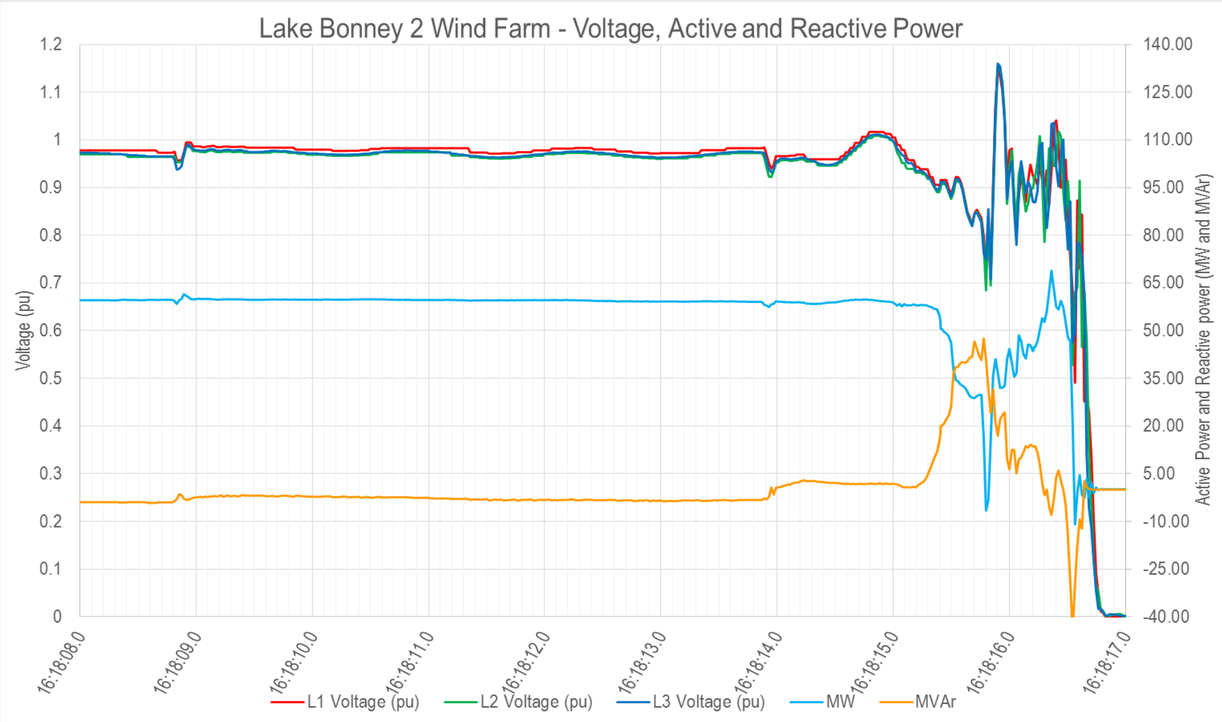
I.1.6 Lake Bonney 1 Wind Farm

Figure 49 Three-phase voltages, active and reactive power at Lake Bonney Wind Farm's connection point



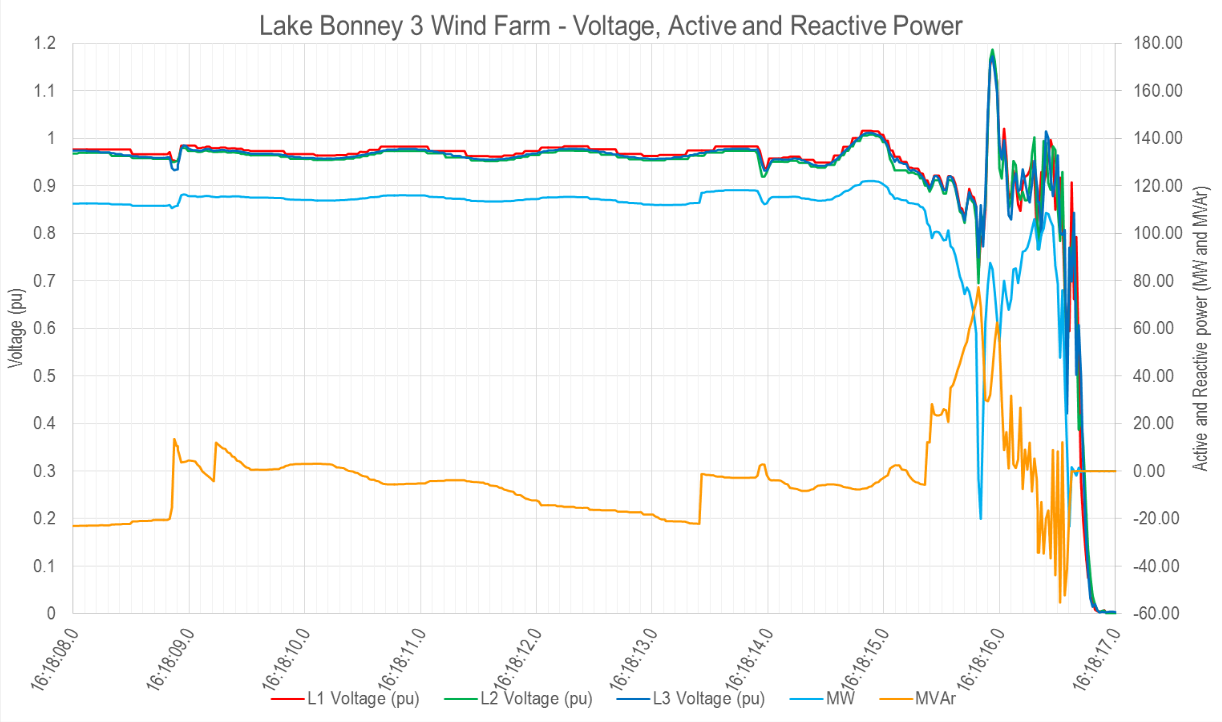
I.1.7 Lake Bonney 2 Wind Farm

Figure 50 Three-phase voltages, active and reactive power at Lake Bonney 2 Wind Farm's connection point



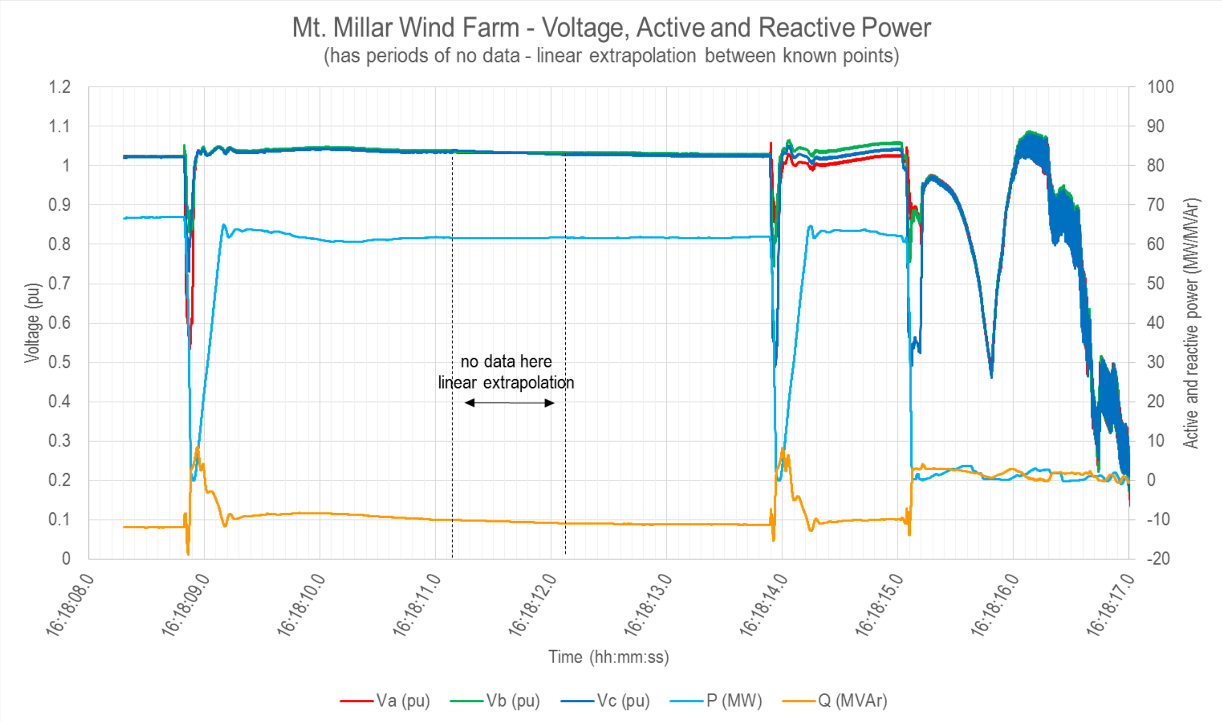
I.1.8 Lake Bonney 3 Wind Farm

Figure 51 Three-phase voltages, active and reactive power at Lake Bonney 3 Wind Farm's connection point



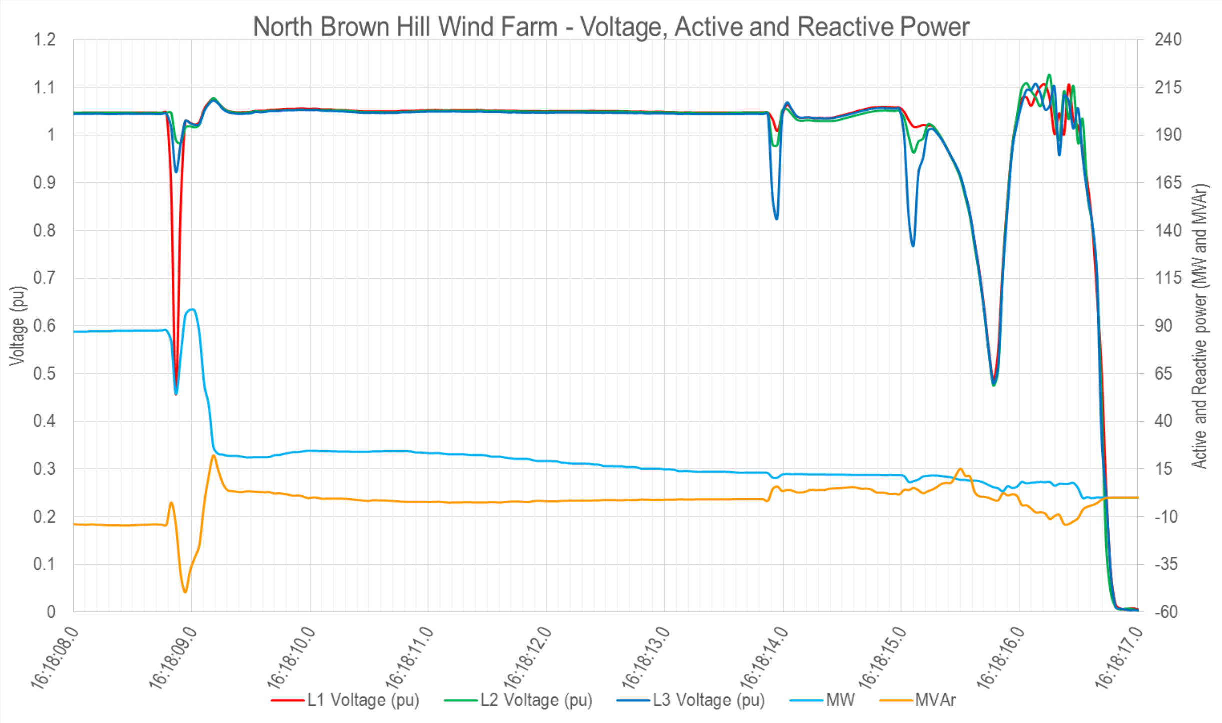
I.1.9 Mt Millar Wind Farm

Figure 52 Three-phase voltages, active and reactive power at Mt Millar Wind Farm's connection point



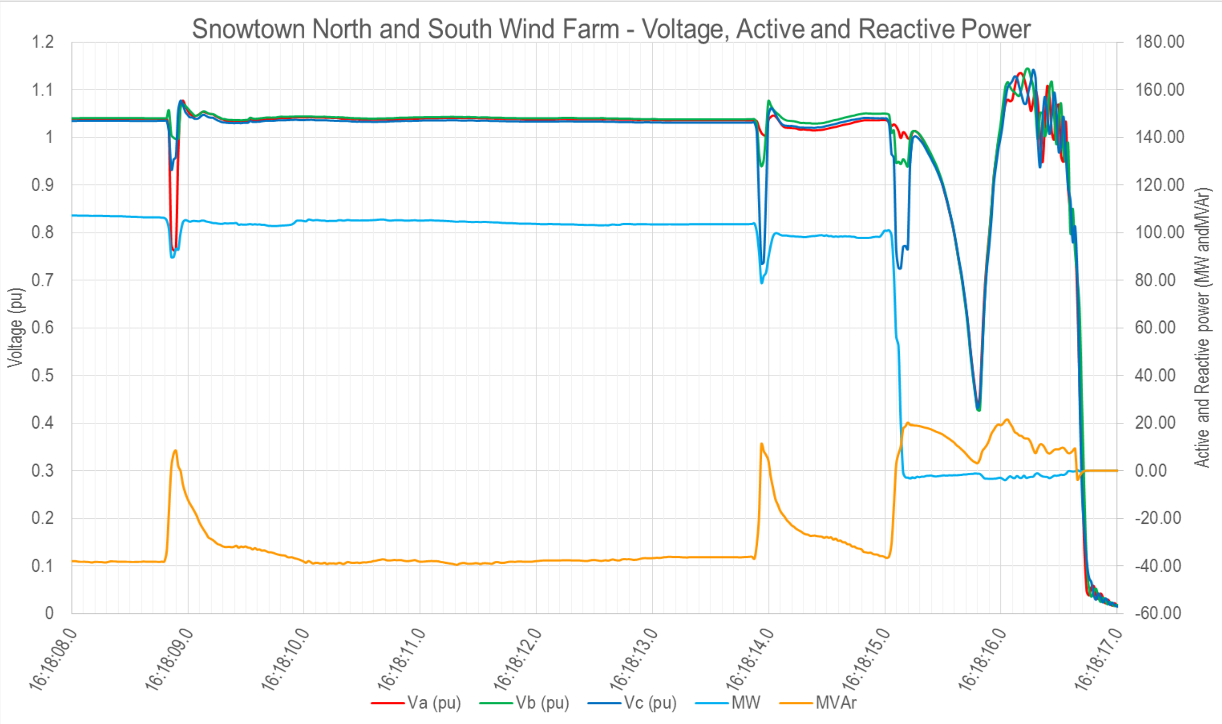
I.1.10 North Brown Hill Wind Farm

Figure 53 Three-phase voltages, active and reactive power at North Brown Hill Wind Farm's connection point



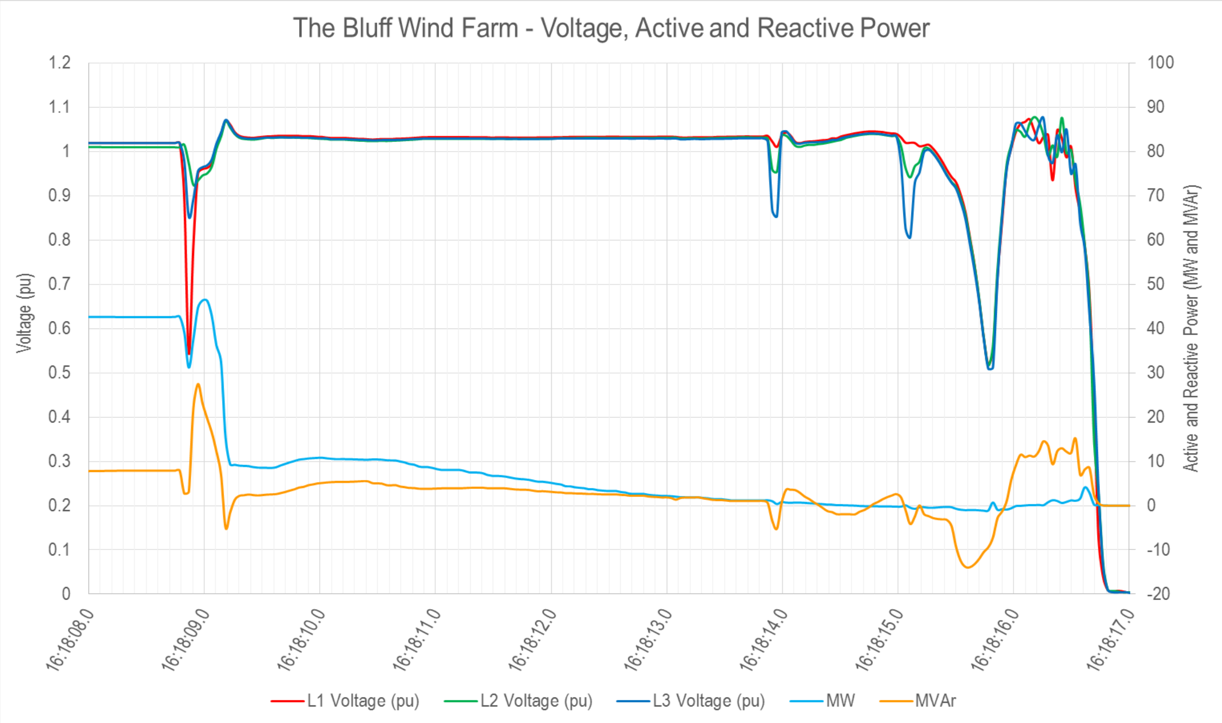
I.1.11 Snowtown II Wind Farm

Figure 54 Three-phase voltages, active and reactive power at Snowtown II Wind Farm's connection point



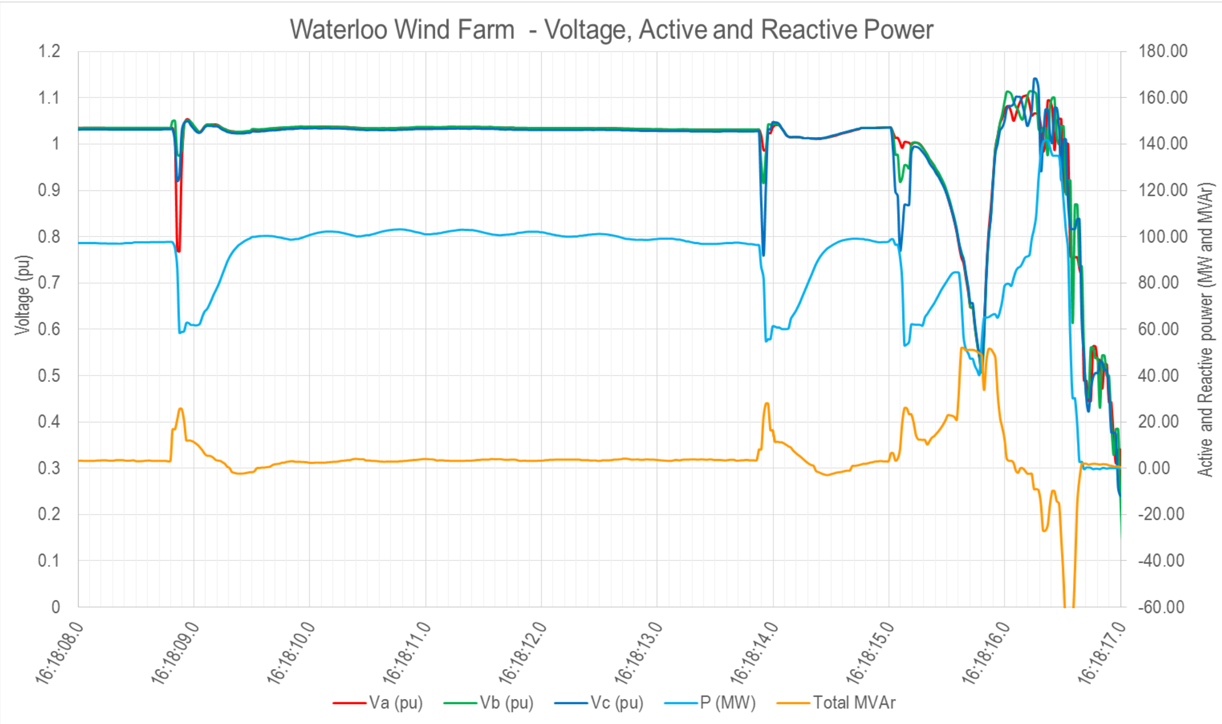
I.1.12 The Bluff Wind Farm

Figure 55 Three-phase voltages, active and reactive power at The Bluff Wind Farm's connection point



I.1.13 Waterloo Wind Farm

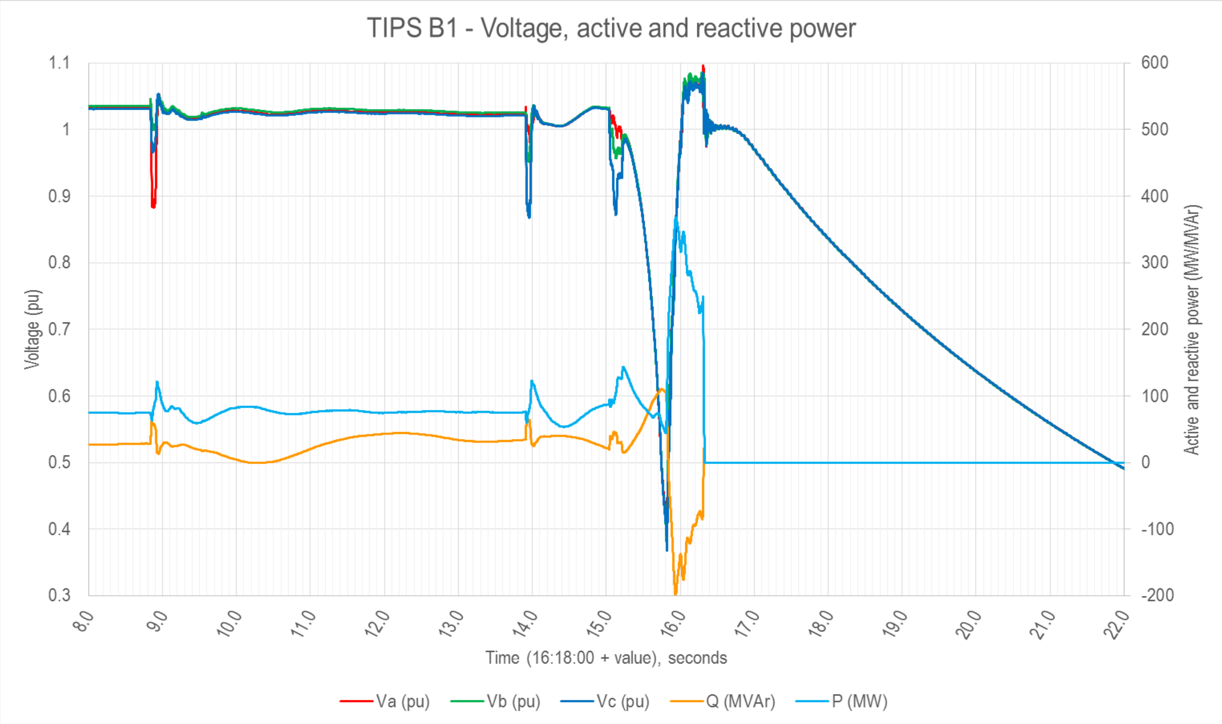
Figure 56 Three-phase voltages, active and reactive power at Waterloo Wind Farm's connection point



I.2 Individual synchronous generating unit's responses

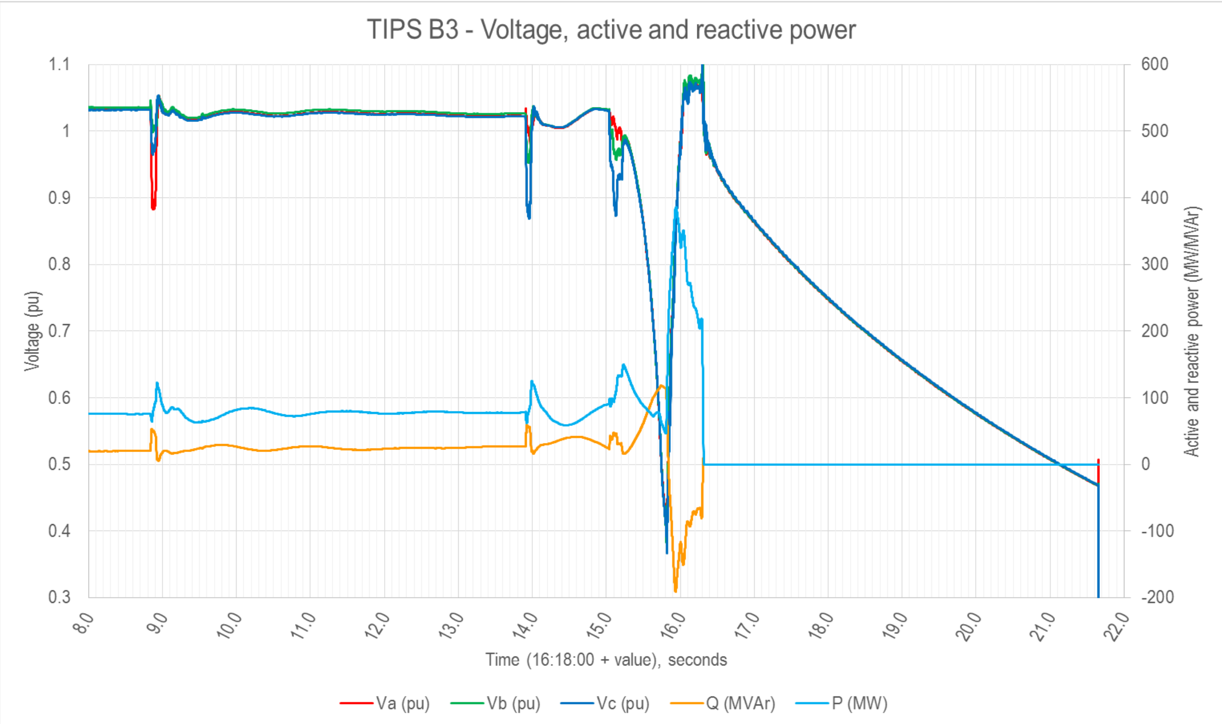
I.2.1 TIPS B1

Figure 57 Three-phase voltages, active and reactive power at TIPS B1 connection point



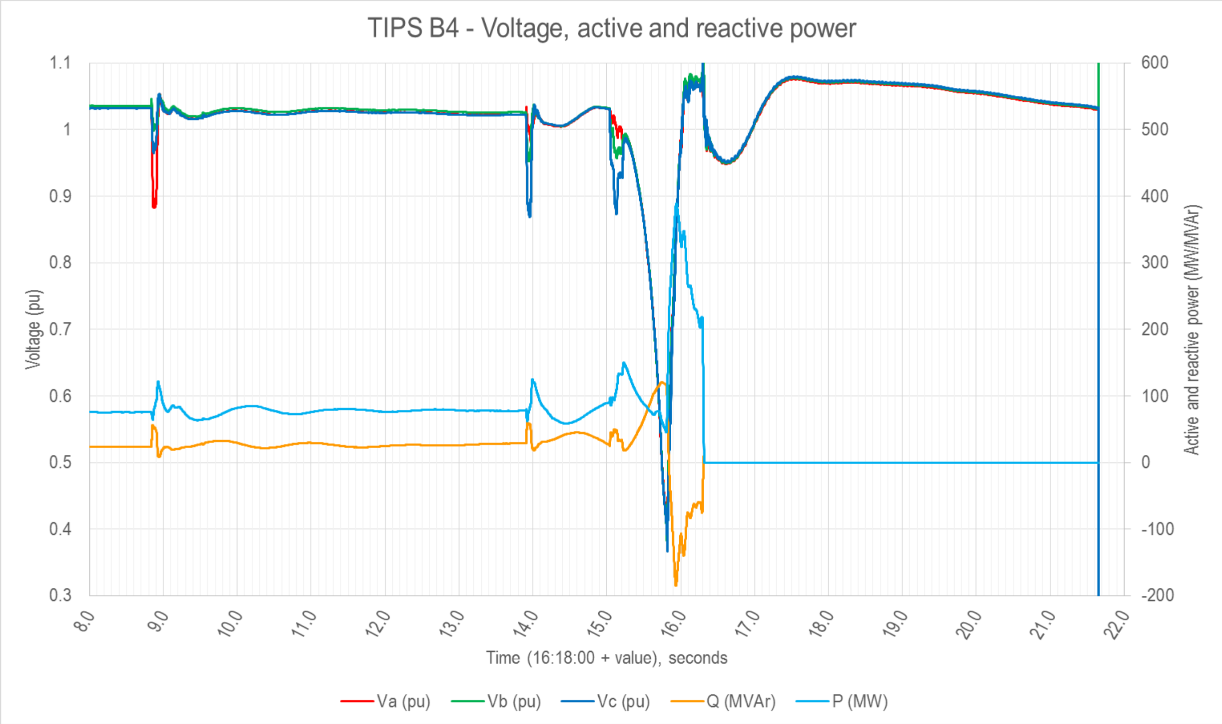
I.2.2 TIPS B3

Figure 58 Three-phase voltages, active and reactive power at TIPS B3 connection point



I.2.3 TIPS B4

Figure 59 Three-phase voltages, active and reactive power at TIPS B4 connection point



I.2.4 Ladbroke Grove units

Figure 60 Three-phase voltages active and reactive power at Ladbroke Grove's connection point

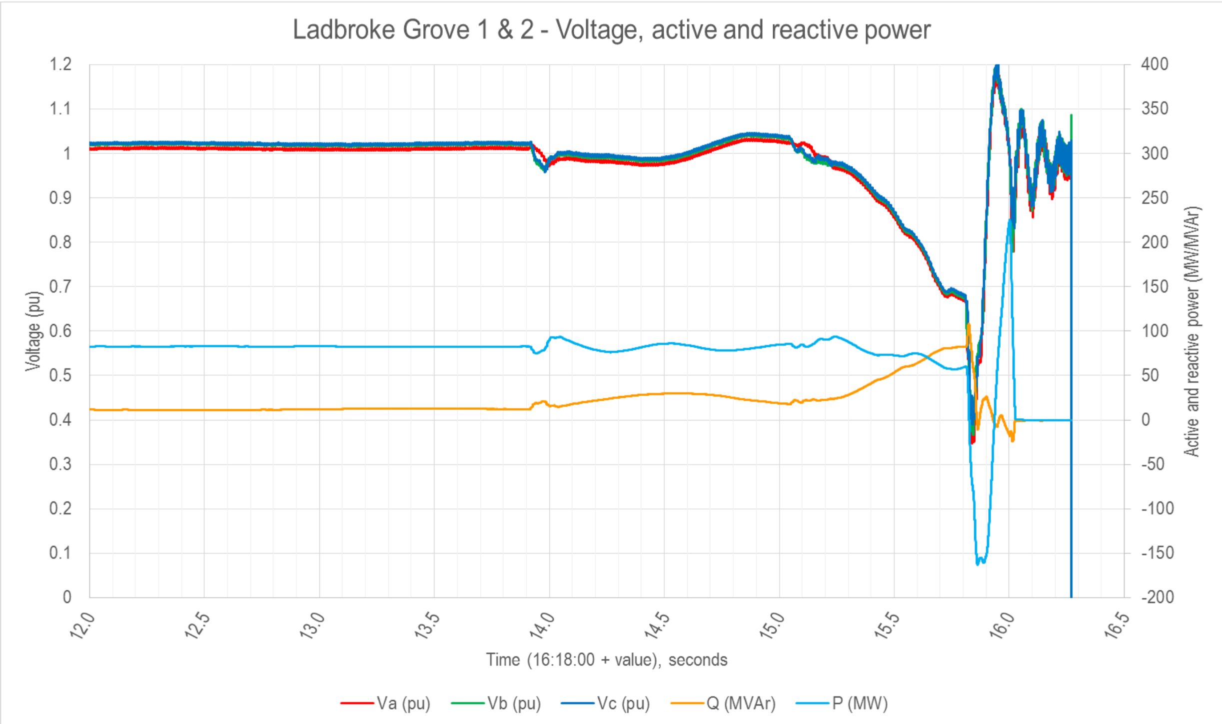
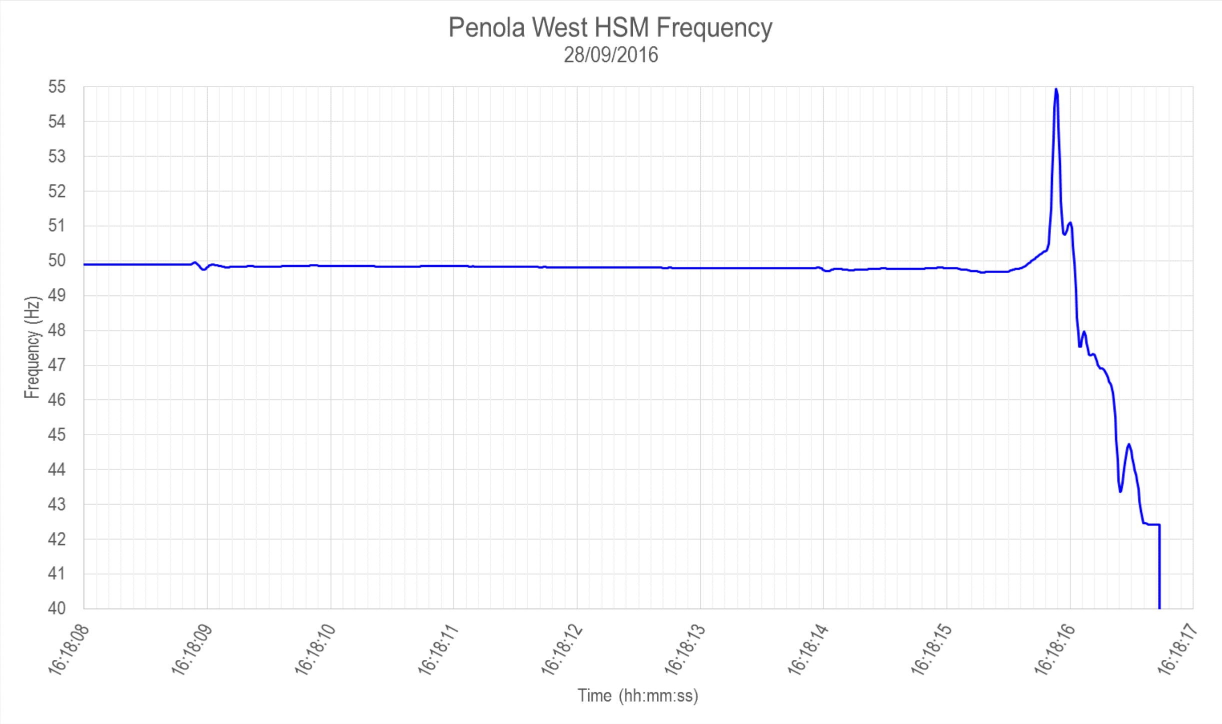


Figure 61 Measured frequency at Penola West to which Ladbroke Grove is connected



APPENDIX J. LOSS OF SYNCHRONISM PROTECTION

J.1 Saddle node bifurcation

An angular difference of 90 degrees is generally used to determine the onset of transient instability and loss of synchronism between two power systems, and is referred to as ‘saddle node bifurcation’ in the power-angle curve.

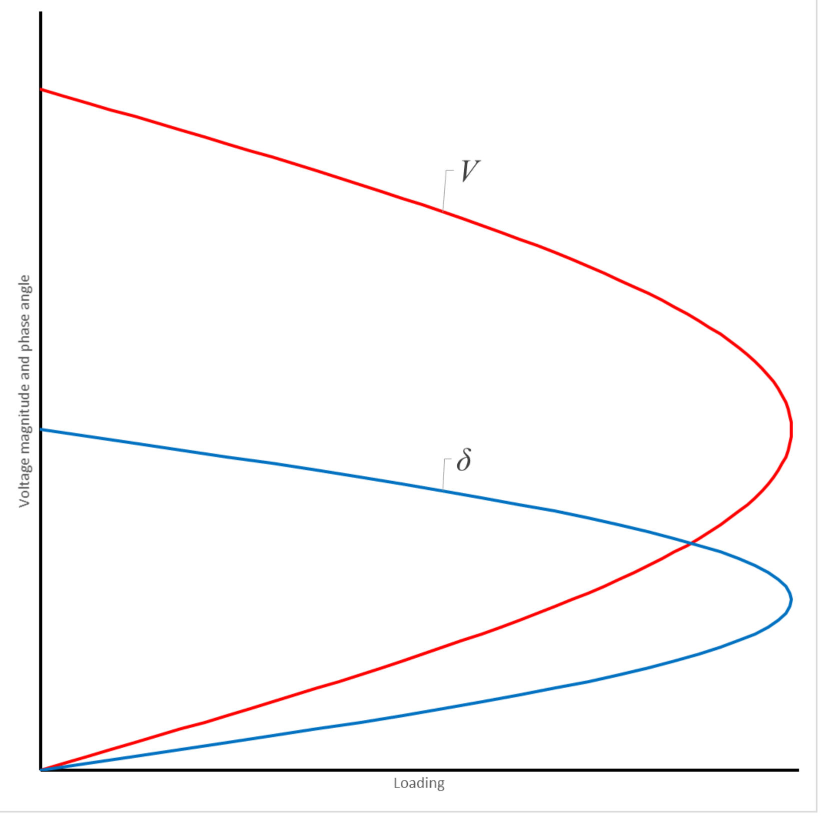
A saddle node bifurcation is the disappearance of a system equilibrium as parameters change slowly. The saddle node bifurcation of most interest to power systems occurs when a stable equilibrium at which the power system operates disappears. The consequence of loss of this equilibrium is that the system state changes dynamically. In particular, the dynamics can be such that voltage or angular instability (or both) occurs as the loading level increases beyond a certain point.

Since the system has two main states of voltage magnitude (V) and phase angle (δ), both should be considered concurrently when determining the stable solution.

Figure 62 shows a bifurcation diagram showing variation of voltage magnitude and phase angle as function of loading. The lower angle solution for δ corresponds to the stable high voltage solution. In this diagram nose of each curve indicates a saddle node bifurcation. The noses of the curves occur at the same loading point indicating the inception of an angular instability makes the voltage instability inevitable and vice versa.

In other words, the saddle node bifurcation of 90 degrees in the power-angle curve corresponds to a saddle node bifurcation in the voltage-power curve, whereby any attempt to transfer more power across the network results in a reduction in system voltages and voltage instability is inevitable.

Figure 62 Bifurcation diagram showing variation of voltage magnitude and phase angle as function of loading



J.2 Operating philosophy of loss of synchronism protection

Power swing blocking and out-of-step tripping relays are generally used in power systems for controlled tripping of certain power system elements as necessary to minimise widespread impact of disturbances, and to protect against loss of synchronism. The operating philosophy is such that the apparent impedance seen by the relay during the steady-state condition is fairly large reflecting healthy system voltages, and currents varying between no load and full load. The apparent steady-state impedance is therefore farm from the relay operating characteristic indicating no spurious tripping will occur.

Power system faults and large power swings due to generation and transmission network disconnection will result in a concurrent reduction in system voltages and an increase in the current flowing through the relay. The apparent impedance will therefore be much smaller than the steady-state impedance. It is therefore likely for the impedance trajectory to enter the relay operating characteristic at which point a trip command (often with a delay) is initiated.

The traditional and most common method used in power swing detection is based on measuring the positive-sequence impedance and the transition time through a blocking impedance area in the R-X (resistance-reactance) diagram. The movement of the impedance for short circuit faults is faster compared to the movement for a power swing.

A timer is started when the impedance measured enters the outer characteristic. If the measured impedance remains between the inner and outer characteristic for the set time delay, it is considered a stable power swing and the tripping of the relay is blocked during a certain time. However, if impedance trajectory crosses the inner and outer characteristic in a time shorter than the set time delay, it is considered either as a short circuit fault or unstable power swing and relay tripping is permitted. After an out-of-step phenomenon has occurred, the relay separates the power system near the power swing centre to curtail the extent of the out-of-step condition and to minimise its impact.

APPENDIX K. HISTORICAL SA SYSTEM SEPARATION EVENTS

This appendix presents Heywood Interconnector MW flow and voltages across the SA power system for relevant system separation events following NEM inception.

K.1 2 December 1999

Figure 63 Heywood Interconnector MW flow, and SA system voltages for 2 December 1999 event

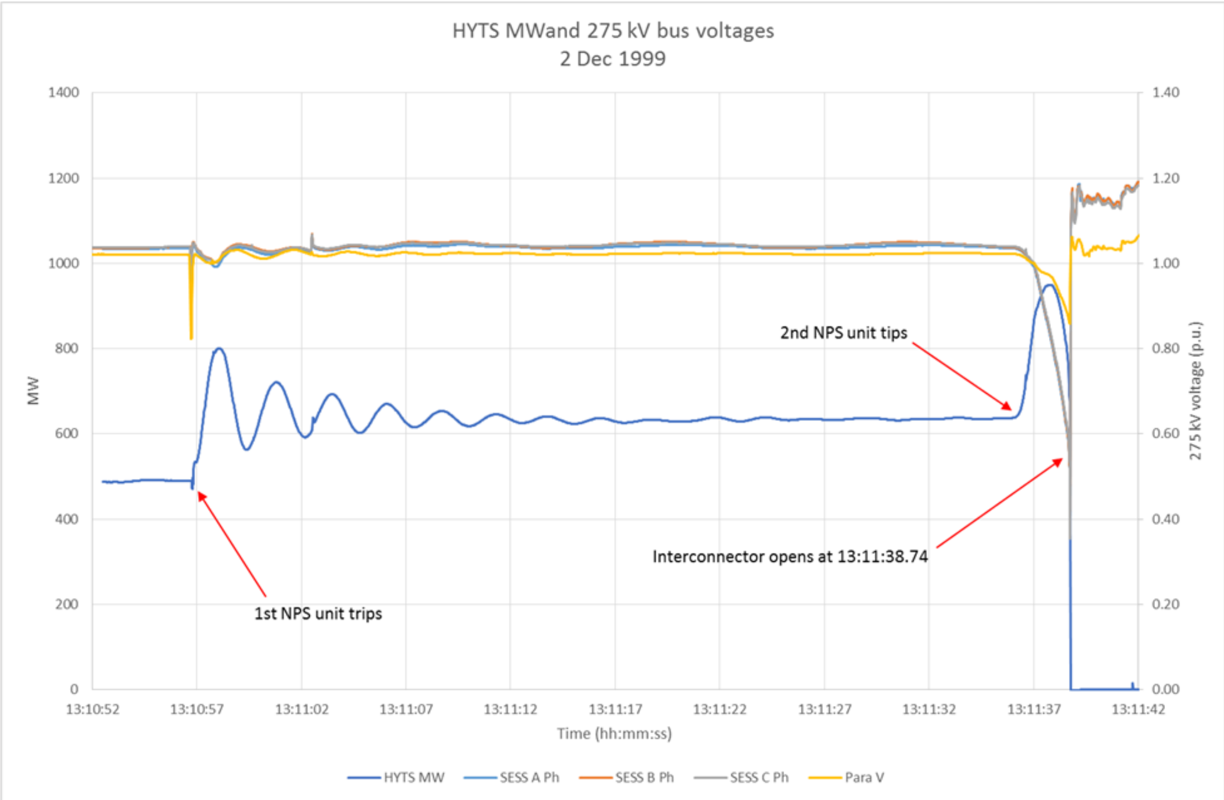


Figure 64 Heywood Interconnector MW flow, and SA system voltages for 2 December 1999 event (zoomed in)

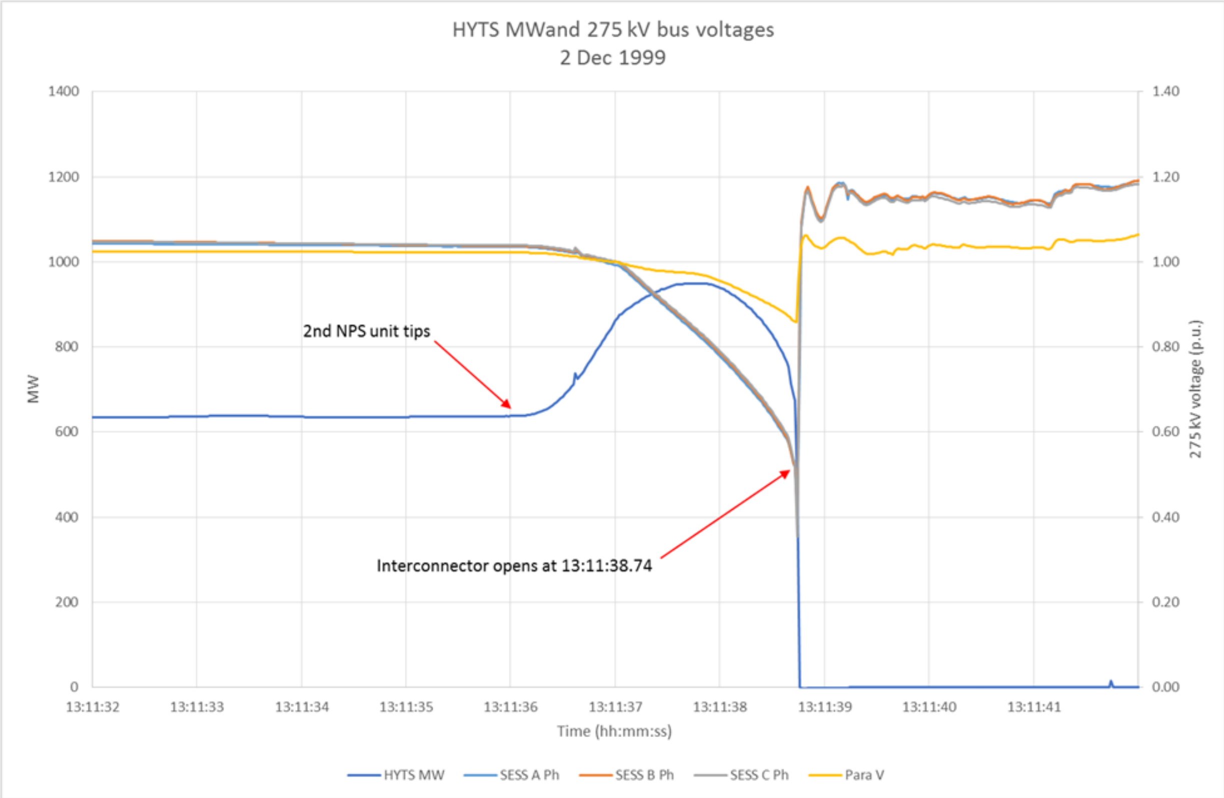
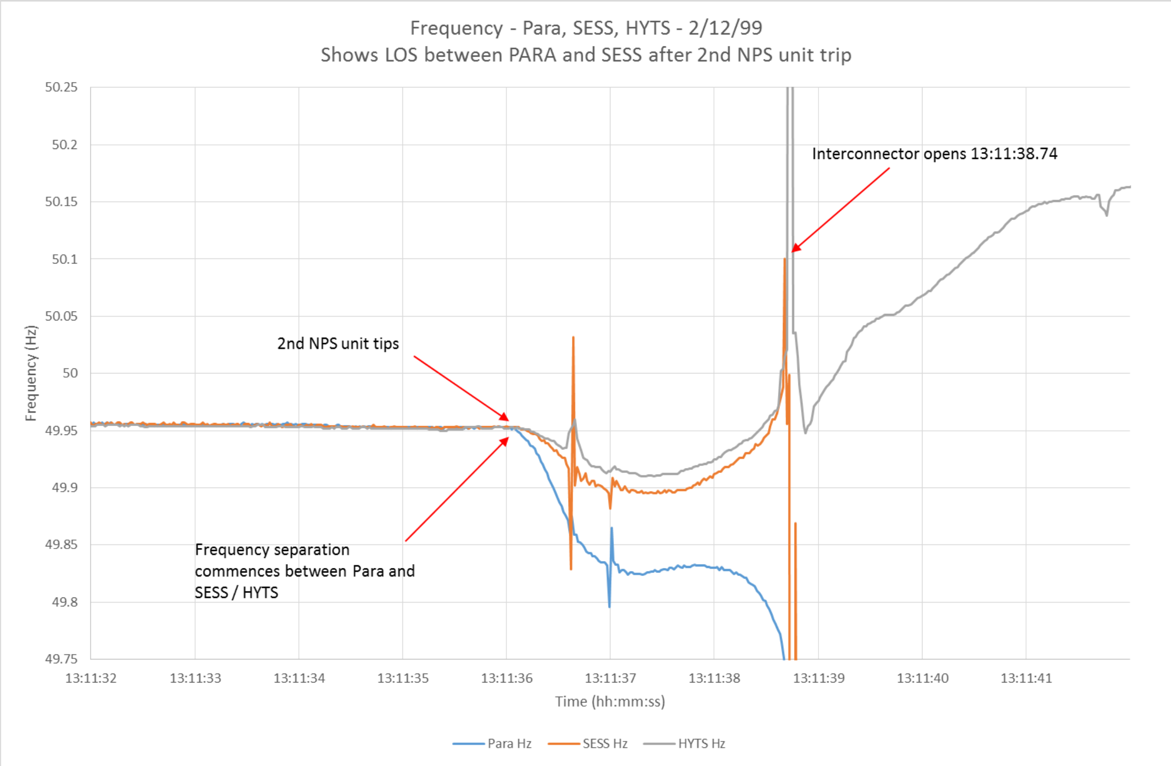


Figure 65 SA and Heywood frequencies for 2 December 1999 event



K.2 8 March 2004

Figure 66 Heywood Interconnector MW flow, and SA system voltages for 8 March 2004 event

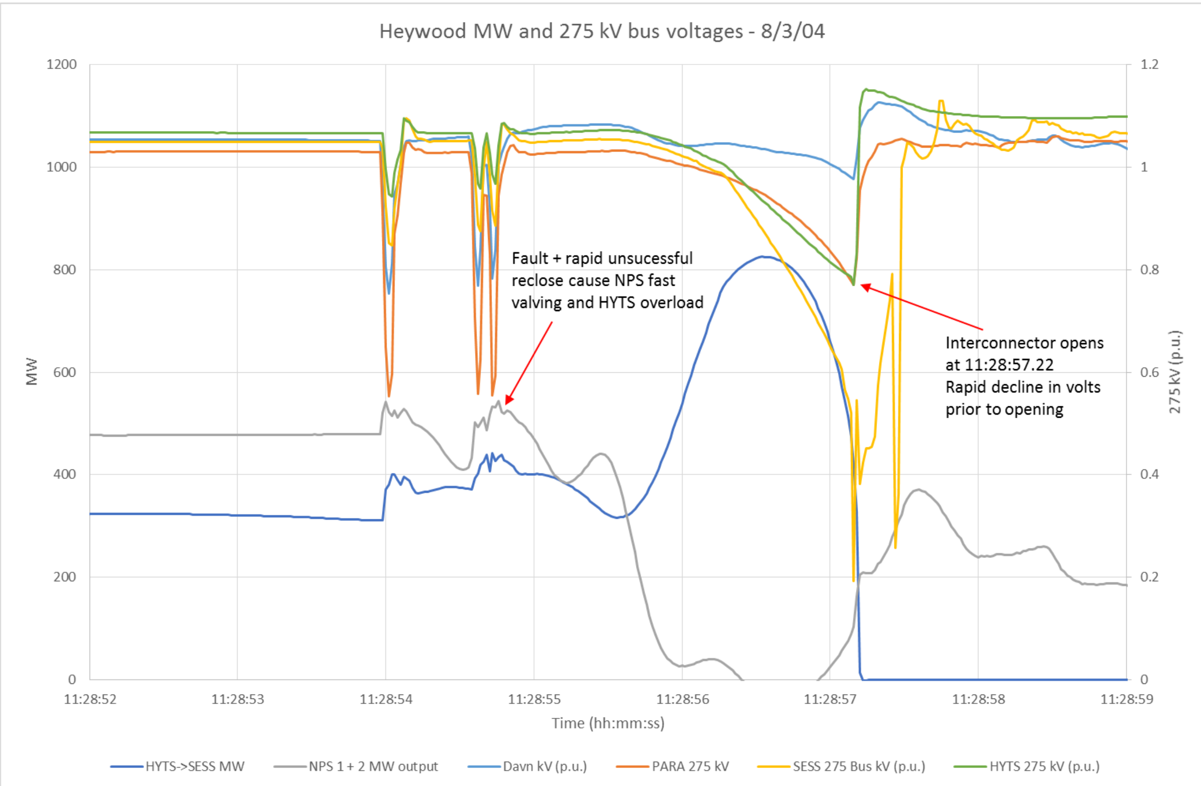
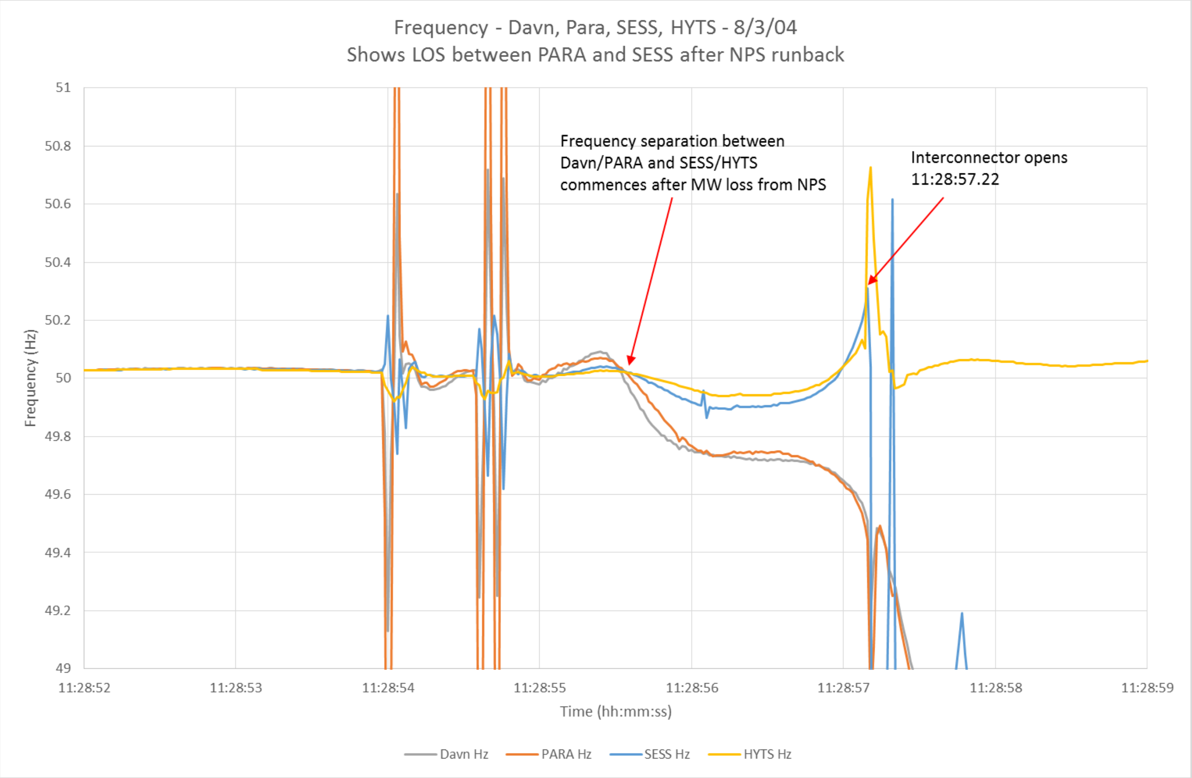


Figure 67 SA and Heywood frequencies for 8 March 2004 event



K.3 14 March 2005

Figure 68 Heywood Interconnector MW flow, and SA system voltages for 14 March 2005 event

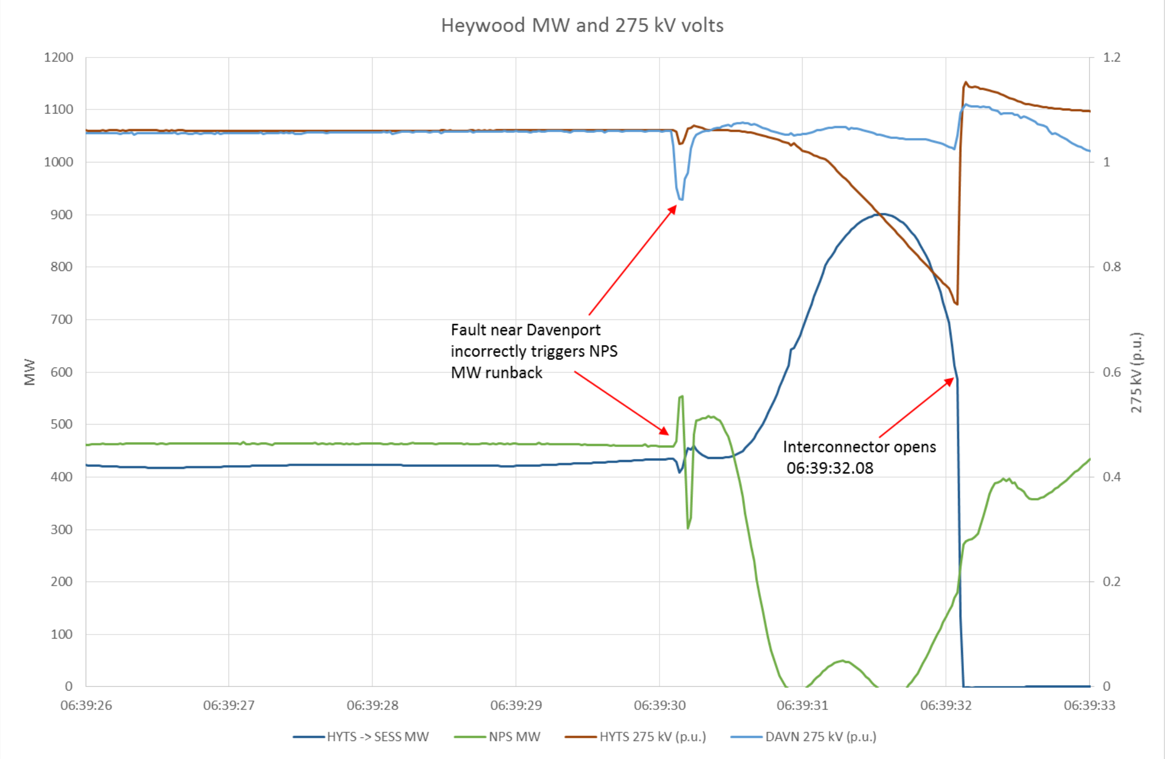
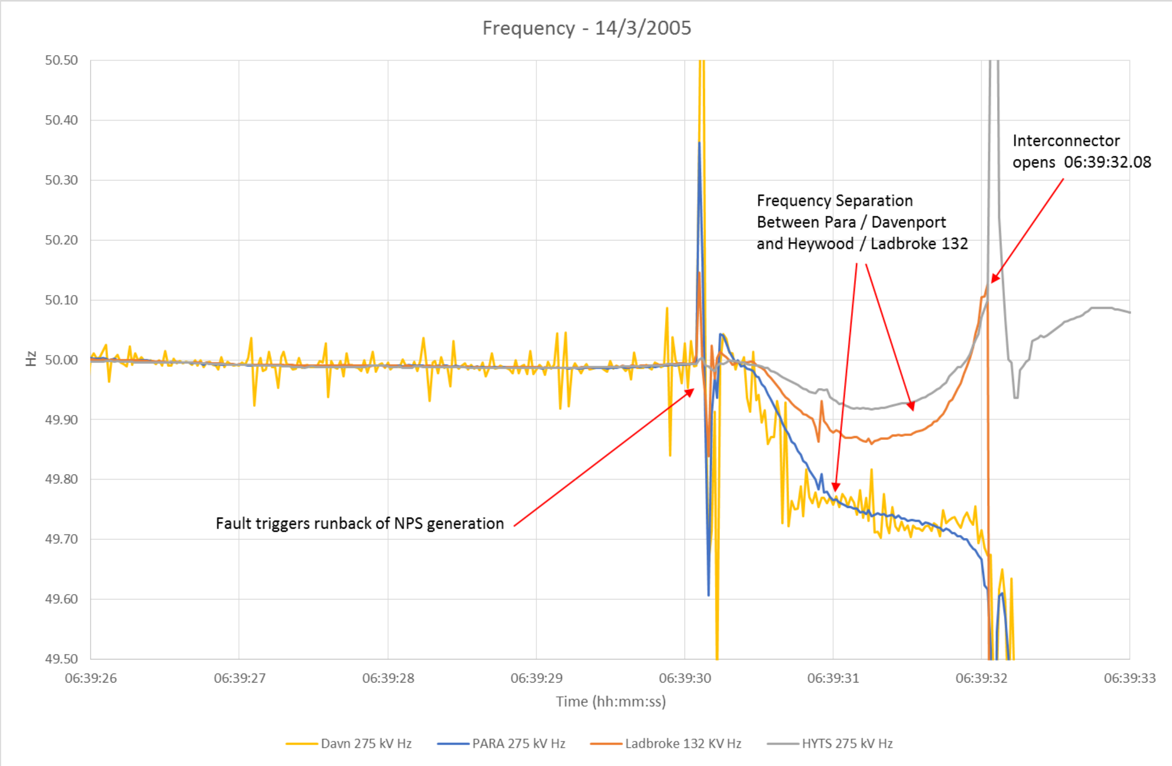


Figure 69 SA and Heywood frequencies for 14 March 2005 event



APPENDIX L. RESPONSE OF NETWORK REACTIVE SUPPORT PLANT

This appendix shows response of the two Para SVCs and series capacitors at Black Range (at this stage AEMO does not have sufficient data to determine the response of South East SVCs).

L.1 Dynamic reactive support plant

Figure 70 Three-phase voltages and MVAr injection by Para SVC1

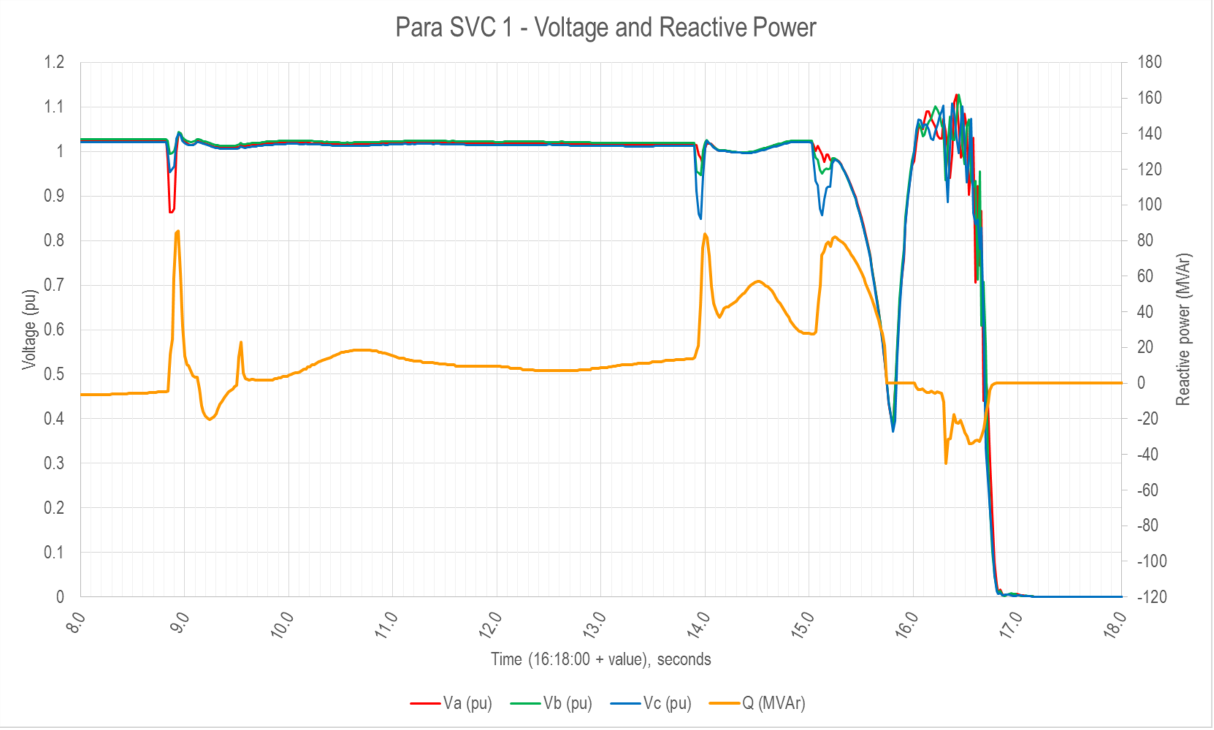
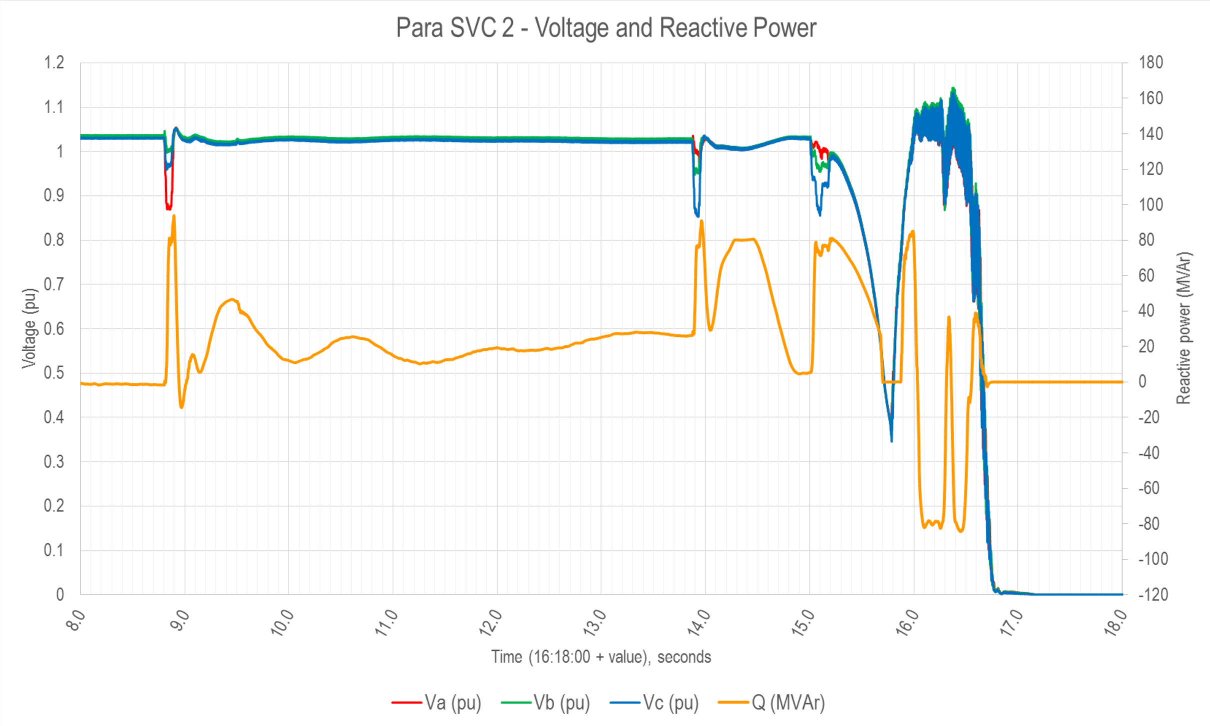
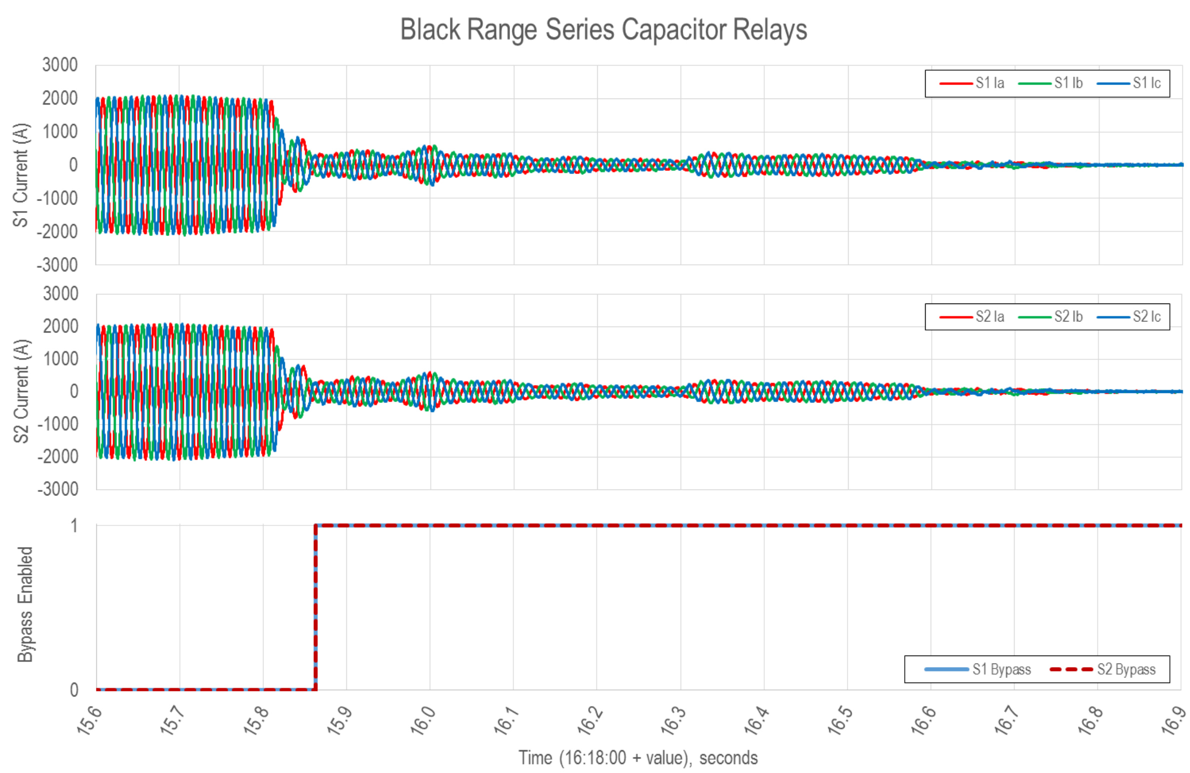


Figure 71 Three-phase voltages and MVAr injection by Para SVC2



L.2 Series capacitors

Figure 72 Current across the two series capacitors and bypass time



APPENDIX M. NETWORK CAPABILITY ANALYSIS

M.1 Network operability with loss of three/four lines

Figure 73 Network capability with loss of three lines assuming no sustained power reduction by wind farms

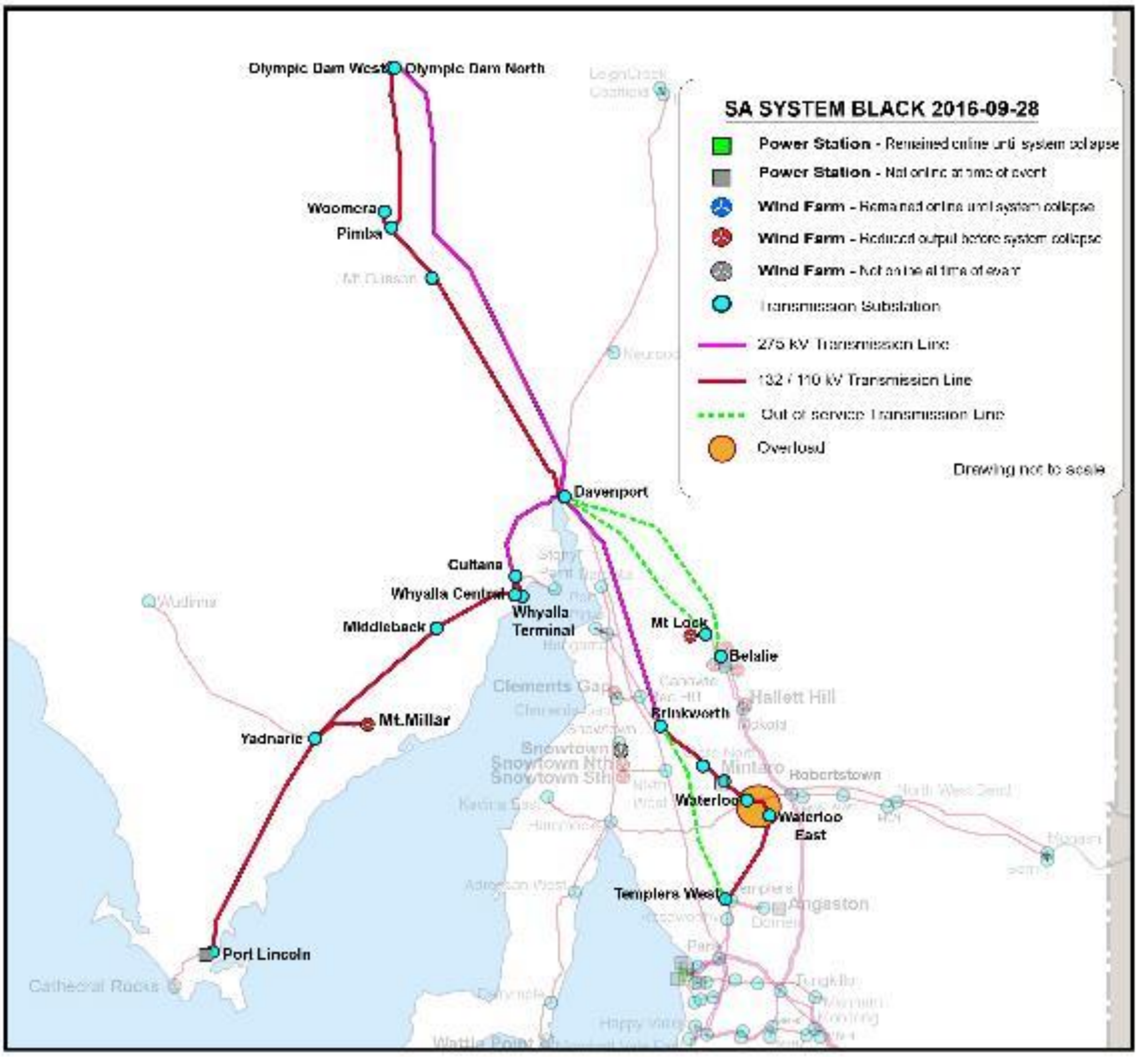
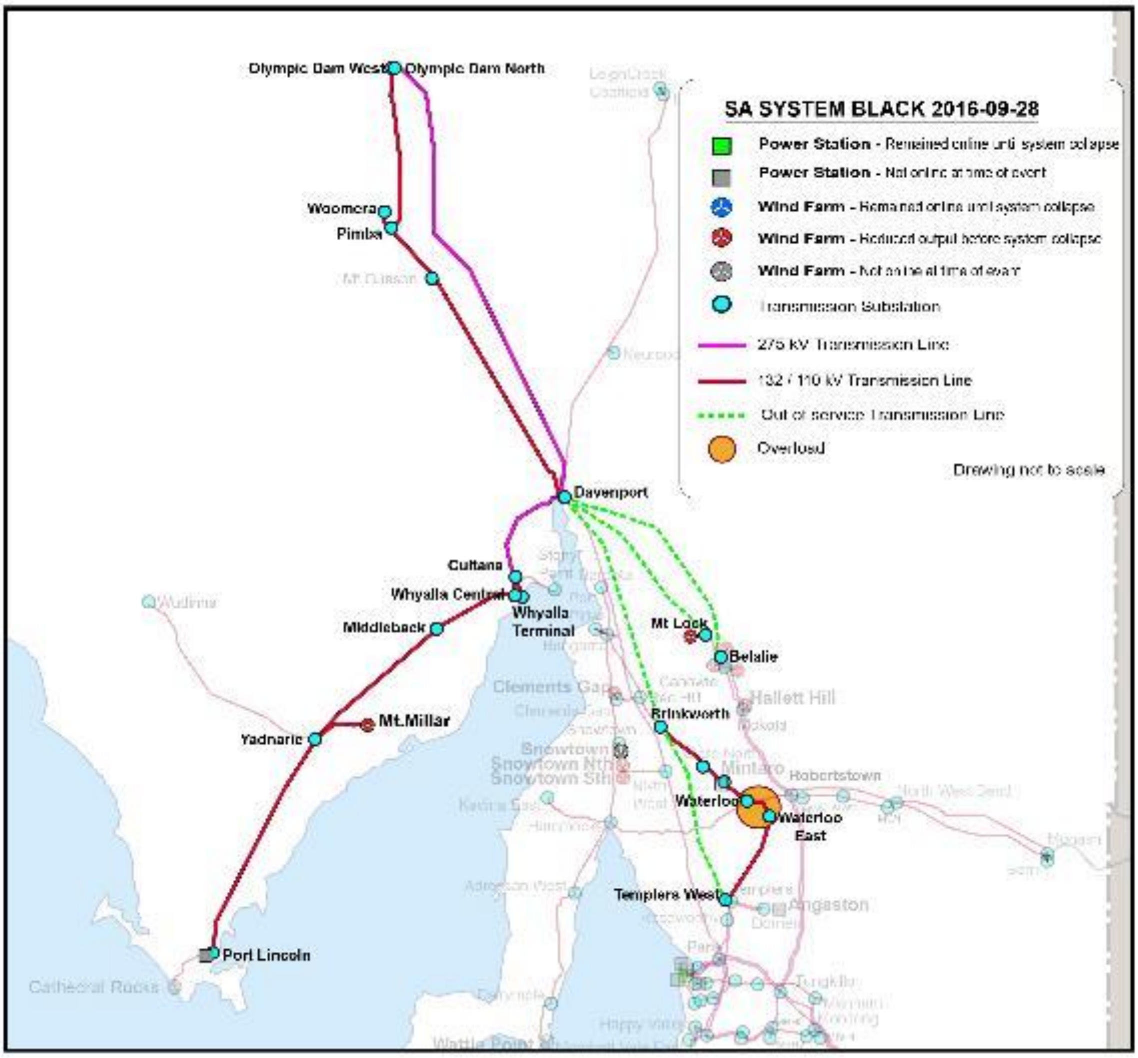


Figure 74 Network capability with loss of four lines assuming no sustained power reduction by wind farms



M.2 PV/QV Anlayses

This section presents results obtained from steady-state PV and QV analyses which determine SA power system transfer capability in the event of loss of four transmission lines, assuming that no sustained power reduction of wind farms would have occurred.

Specifically, these studies are used to: determine:

- Determine the maximum transfer of power between two substations before the voltage collapse point.
- Confirm reactive power margin available in a given location, so as to maintain all system voltages within the continuous uninterrupted operating range.

The objective of the PV and QV analyses is to determine the ability of a power system to maintain voltage stability at all locations in the system under normal and contingency operating conditions.

The PV and QV curves are obtained through a series of load flow solutions. The PV curve is a representation of voltage change as a result of increased power transfer between two systems, and the QV curve is a representation of reactive power demand by a bus or buses as voltage level changes.

As power transfer is increased, voltage decreases at some buses on or near the transfer path. Transfer can continue to increase until the solution identifies a condition of voltage collapse, or when the numerical solutions of the load flow equations cannot be solved.

M.3 Heywood Interconnector

Figure 75 South East voltages versus Heywood transfers

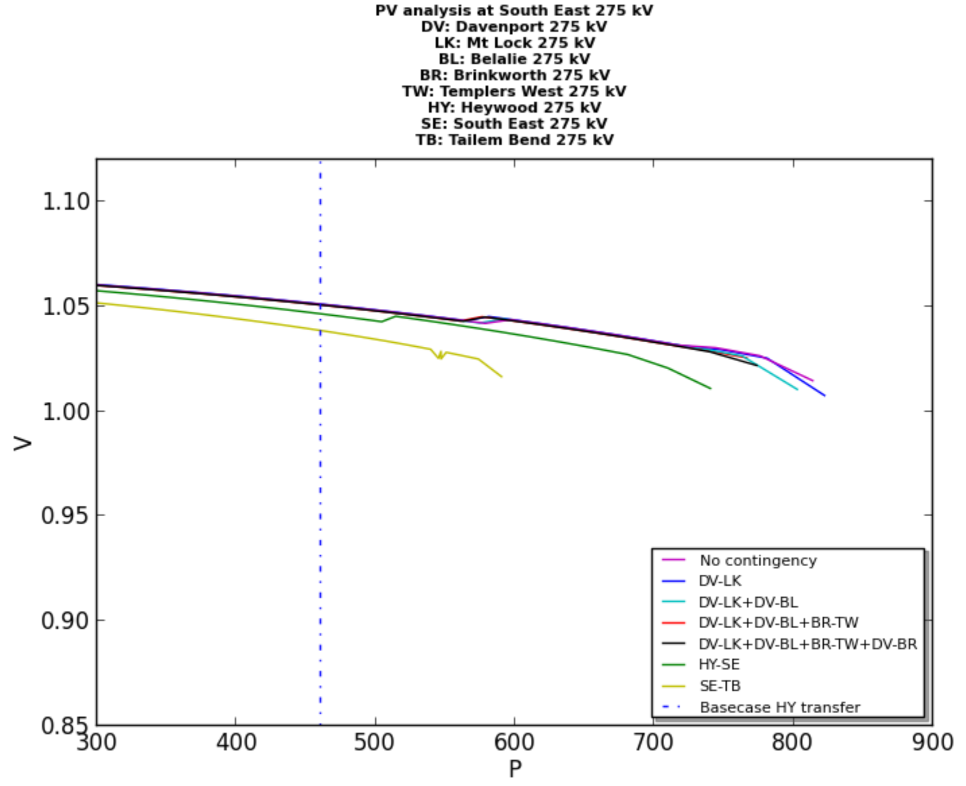


Figure 76 QV plots at South East with varying Heywood transfers (no contingency)

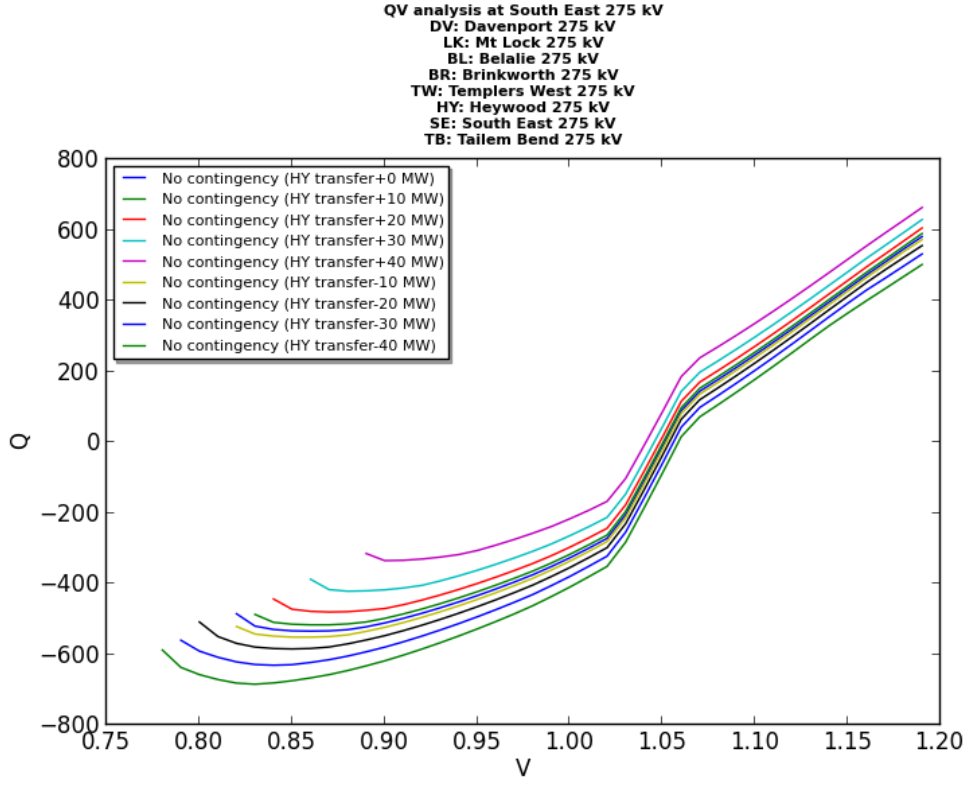
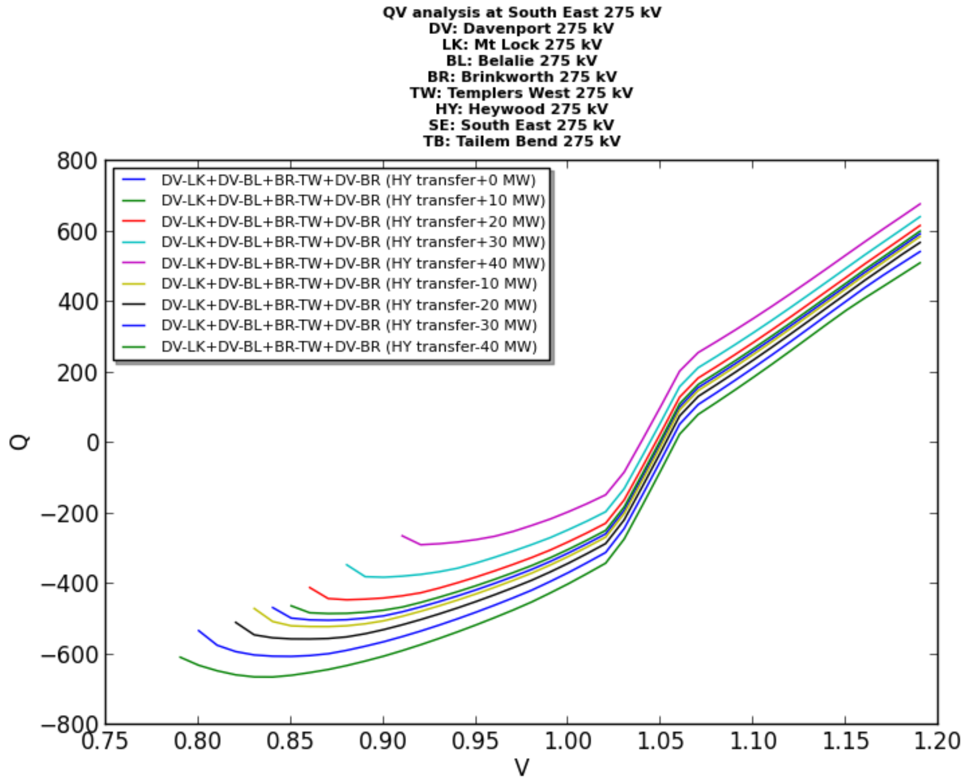


Figure 77 QV plots at South East with varying Heywood transfers (four-line contingency at Davenport)



M.4 Davenport

Figure 78 Davenport voltages versus Davenport demand

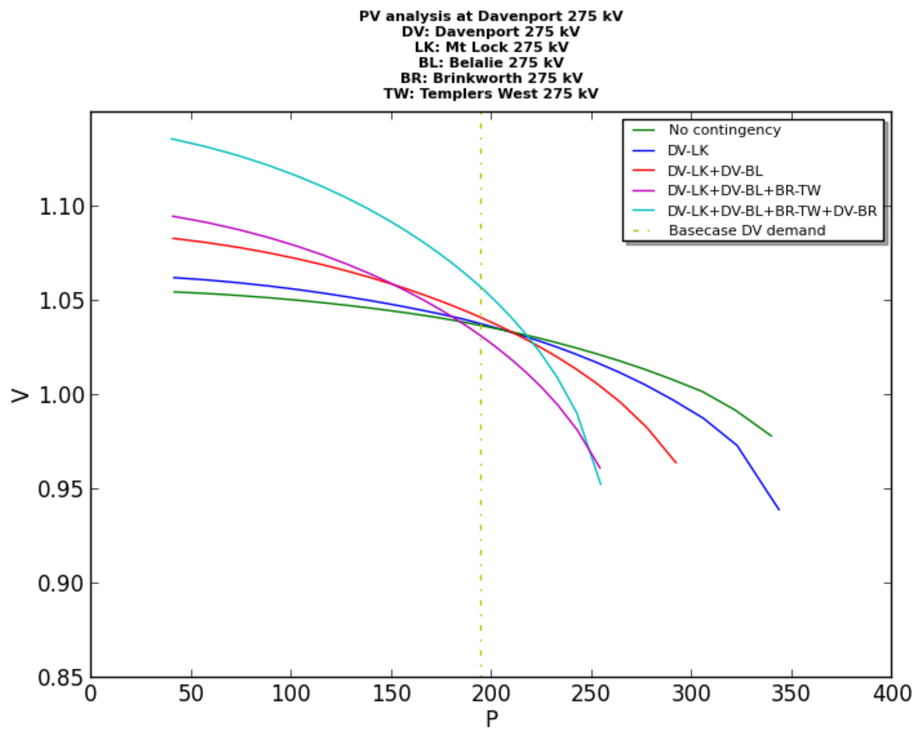


Figure 79 QV plots at Davenport with varying Davenport demand (no contingency)

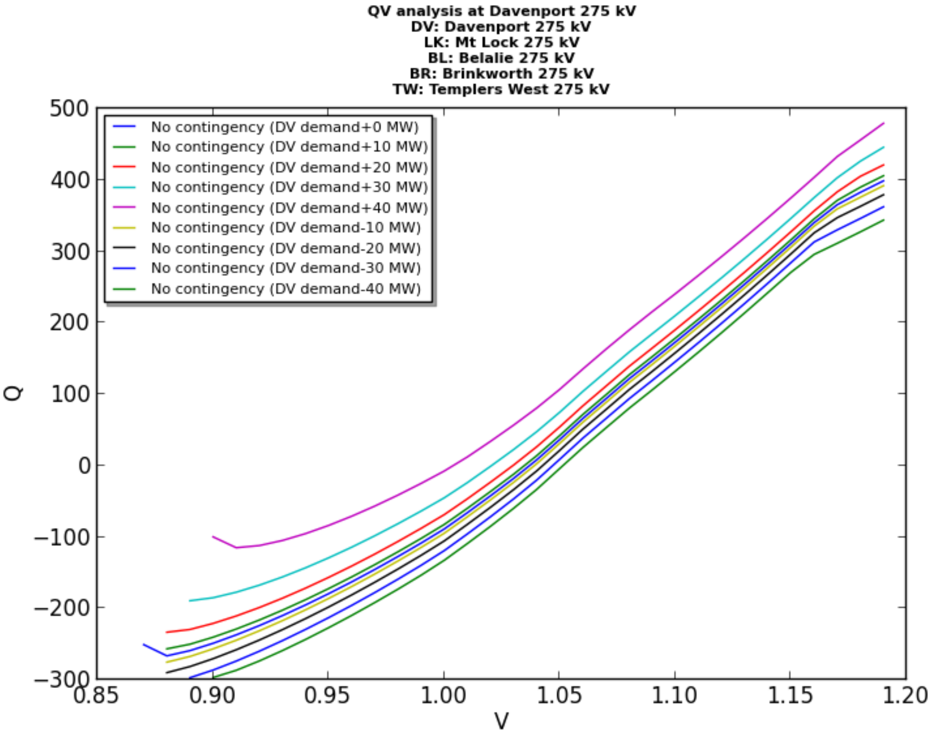
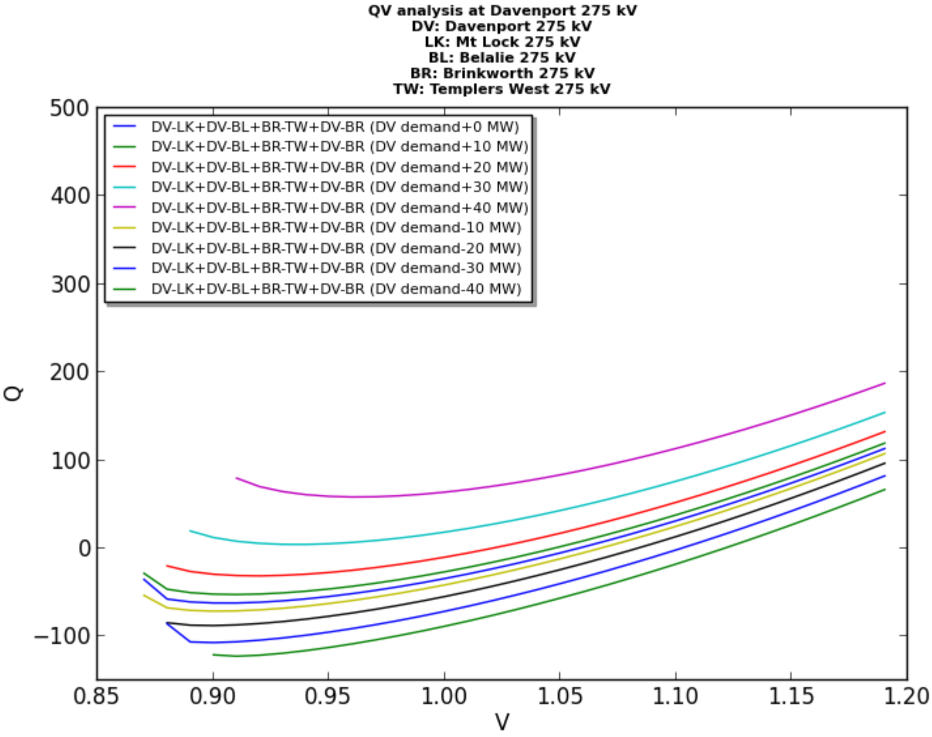


Figure 80 QV plots at Davenport with varying Davenport demand (four-line contingency in Davenport)



M.5 Robertstown

Figure 81 Para voltages versus Robertstown transfers

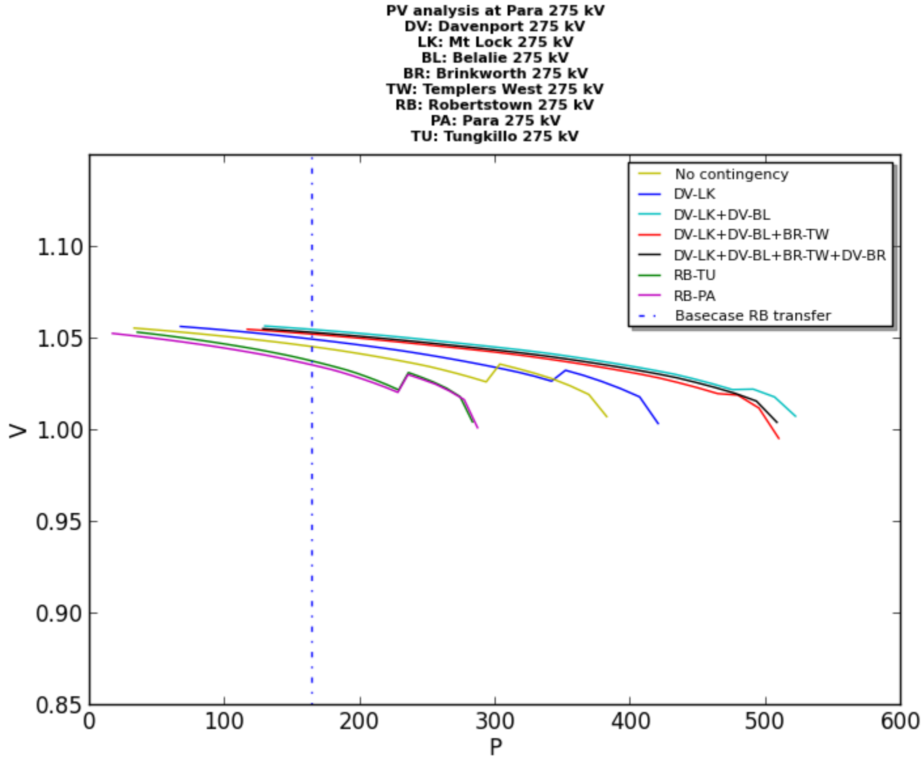


Figure 82 QV plots at Para with varying Robertstown transfers (no contingency)

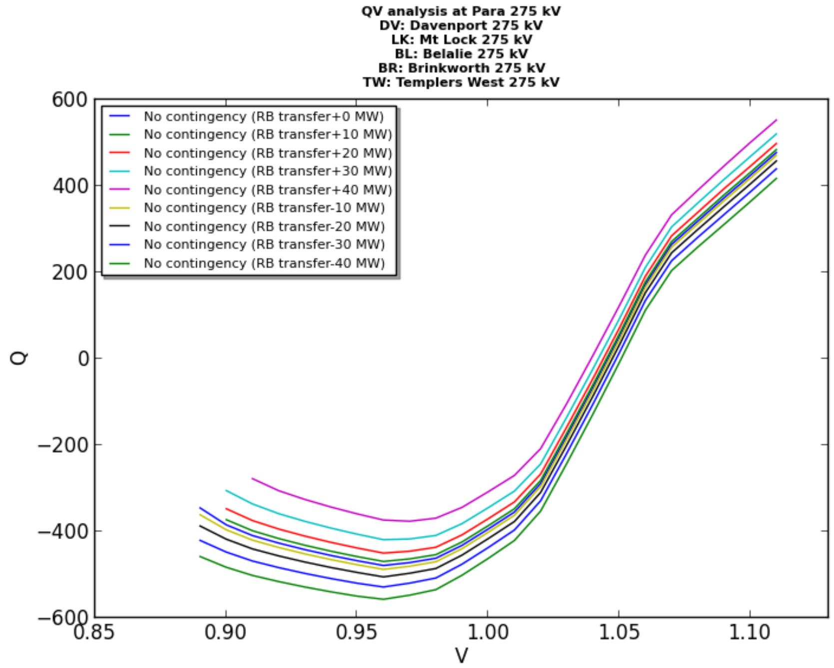
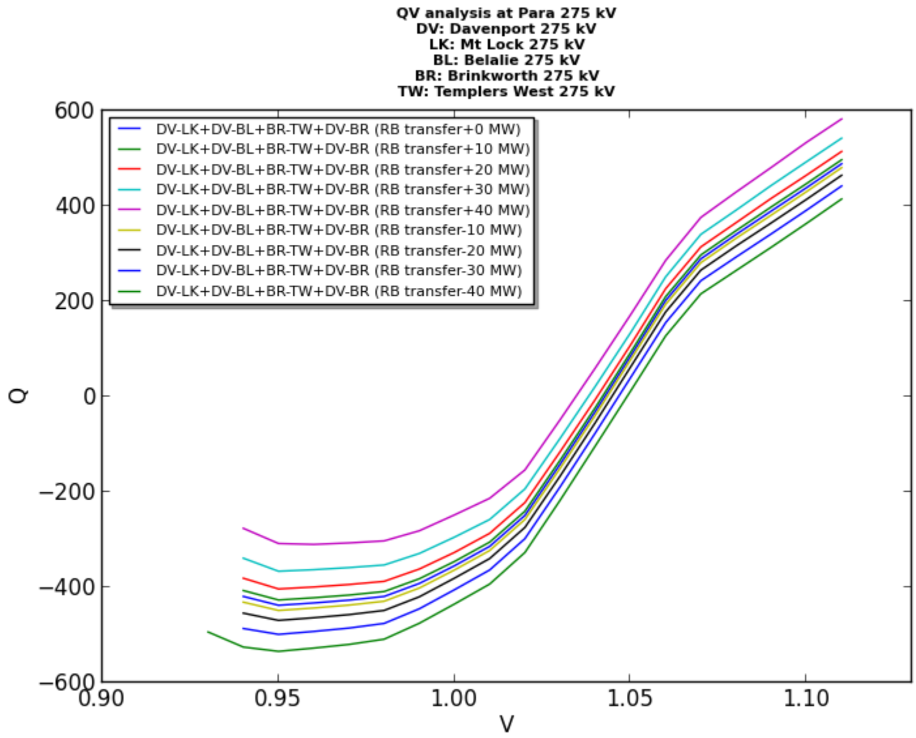


Figure 83 QV plots at Para with varying Robertstown transfers (four-line contingency at Davenport)



APPENDIX N. WEIGHTED SHORT CIRCUIT RATIO

Conventional calculation methods for determining short circuit ratio (SCR) gives rise to misleading results for wind farms that are part of an electrically close cluster. This is because adjacent wind farms must be thought of one large installation. Each wind farm will therefore only get a portion of the overall available fault current, not the entire fault current to itself.

Three alternative methods were developed for calculating the SCR for multiple concentrated wind farms. These will be presented in the upcoming CIGRE Technical brochure on Connection of Wind Farms to Weak AC Networks.

Another appropriate index for the calculation of impact of adjacent wind farms is the weighted short circuit ratio (WSCR), defined by:

$$\mathrm{WSCR} = \frac{\mathrm{Weighted} \quad S_{\mathrm{SCMVA}}}{\sum_{i}^{N} P_{\mathrm{RMWi}}}$$

$$= \frac{(\sum_{i}^{N} S_{\mathrm{SCMVAi}} * P_{\mathrm{RMWi}}) / \sum_{i}^{N} P_{\mathrm{RMWi}}}{\sum_{i}^{N} P_{\mathrm{RMWi}}}$$

$$= \frac{\sum_{i}^{N} S_{\mathrm{SCMVAi}} * P_{\mathrm{RMWi}}}{(\sum_{i}^{N} P_{\mathrm{RMWi}})^{2}}$$

where S_{SCMVAi} is the short circuit capacity at bus i before the connection of Wind farm i and P_{RMWi} is the MW rating of WPP i to be connected. N is the number of Wind farm fully interacting with each other and i is the Wind farm index.

The proposed WSCR calculation method is based on the assumption of full interactions between wind farms. This is equivalent to assuming that all wind farms are connected to a virtual connection point. For a real power system, there is usually some electrical distance between each wind farm’s connection point and the wind farms will not fully interact with each other.

Note that conventional WSCR method calculates the equivalent short circuit ratio at a virtual connection point. However, wind turbine manufacturers specify the minimum permissible short circuit ration at the 33 kV side of the wind turbine transformers. To allow for a like-for like comparison, the WSCR calculated at the virtual connection point is reflected back into the 33 kV wind turbine terminals.

APPENDIX O. ROLES AND RESPONSIBILITIES

Restoration of supply would be required following a ‘major supply disruption’, or ‘Black System’, as those terms are defined in the NER. By definition, a Black System can occur following a major supply disruption.

Restoration relies on co-operation between four groups whose roles are discussed briefly below. Section O.5 addresses system restart training.

O.1 AEMO

AEMO is responsible for the co-ordination of restoration. This includes:

- Being restoration ready, including:
  - Having a ‘system restart plan’ in place at all times, as required by clause 4.8.12 of the NER. While AEMO has a system restart plan for each regions, AEMO adapts it as a basis for use in the circumstances of the major supply disruption.
  - Developing communication protocols with NSPs to apply during a restoration in accordance with clause 4.8.12 of the NER.
  - Having secured SRAS by entering into contracts for the supply of SRAS in accordance with clause 3.11.9 of the NER.
- During a major supply disruption, this includes:
  - Securing the power system.
  - Advising the market of the existence of a major supply disruption, or Black System.
  - Determining, in conjunction with the relevant TNSPs, the cause of the major supply disruption or Black System.
  - Ascertaining, in conjunction with the relevant TNSPs, the status of the power system.
  - Developing a restoration strategy in conjunction with the relevant TNSPs.
  - Requiring the provision of SRAS.
  - Managing the restoration process.
  - Advising the market of the progress of the restoration.
- At the conclusion of the restoration:
  - Advising the market that the system has returned to normal operation.

O.2 TNSPs

TNSPs are key players during any restoration. Their role includes:

- Being restoration ready, including:
  - Providing AEMO with their ‘Local Black System Procedures’, as required by clause 4.8.12 of the NER.
  - Assisting AEMO in the development of the communication protocols required by clause 4.8.12 of the NER.
  - Assist AEMO in determining the capability of any proposed SRAS in accordance with clause 3.11.9(i) of the NER.
- During a major supply disruption, this includes:
  - Determining the cause of the major supply disruption in conjunction with AEMO.
  - Determining the status of the transmission network and advising AEMO.
  - Assisting in the development of a restoration strategy with AEMO.

  - Switching circuits on the transmission network in accordance with AEMO's restoration strategy, including converting AEMO's broad instructions into detailed switching sequences.
  - Liaising with AEMO on restoration of the transmission network.
  - Liaising with AEMO and DNSPs on load restoration.
  - Managing voltage levels in conjunction with AEMO.
  - Keeping AEMO advised of progress of the restoration, and supplying any other information AEMO requests.

O.3 DNSPs

DNSPs are key players during any restoration. Their role includes:

- Being restoration ready, including:
  - Providing AEMO with their 'Local Black System Procedures', as required by clause 4.8.12 of the NER.
  - Assisting AEMO in the development of the communication protocols required by clause 4.8.12 of the NER.
- During a major supply disruption, this includes:
  - Responding to instructions to restore load from their local TNSP.
  - Perform switching on their distribution system in preparation for load restoration.
  - Liaising with TNSPs on load restoration.
  - Managing loads and load restoration.

O.4 Generators

Generators are key players during any restoration. Their role includes:

- Being restoration ready, including:
  - Providing AEMO with their 'Local Black System Procedures', as required by clause 4.8.12 of the NER.
  - Assisting AEMO in the development of the communication protocols required by clause 4.8.12 of the NER.
  - Some will enter into contracts for the supply of SRAS in accordance with clause 3.11.9 of the NER.
- During a major supply disruption, this includes:
  - Providing SRAS if they have a contract for the supply of SRAS upon AEMO's instructions.
  - Stabilising their on-line plant on-line and supplying electricity.
  - Stabilising any plant that has tripped to house load.
  - Advising AEMO of:
    - Any urgent requirement for load to stabilise on-line plant.
    - Status of plant and ability to supply electricity.
    - Any requirement for a start-up supply.

O.5 Staff competency

Although Black System conditions are rare events, it is essential that all staff likely to be involved in a system restart are suitably trained.

Every six months, AEMO Control Room staff are required to attend System Restart training sessions on the Dispatch Training Simulator.

AEMO also invites NEM Participants to attend the training sessions, with regular participation by staff from TNSP, DNSP, and power station control rooms, trading room staff, and Government agencies.

The objective of the training is to review the latest System Restart plans and provide an overview of the operational issues and market processes involved in a system restart.

As part of each training session, an exercise is conducted using the Simulator to restore a NEM Region after a Black System. During this exercise, the trainees are required to:

- Devise and implement an agreed restoration plan.
- Manage load restoration, taking into consideration load block size and high priority/sensitive loads.
- Activate SRAS contracts as required.
- Prioritise tasks and actions.
- Determine the cause of the contingency and assess the status of the power system in conjunction with the relevant TNSPs.
- Advise participants and crisis management teams of restoration progress at regular intervals.
- Determine if an exit of the Black System declaration can occur.
- Determine if resumption of the spot market can occur.

In 2016, AEMO conducted System Restart training sessions covering the Queensland and SA regions.

APPENDIX P. SYSTEM RESTART ANCILLARY SERVICES

SRAS is a contracted service to restart a power system following a Black System event. SRAS is provided by a generating unit, or combination of generating units, that can be started without requiring electricity from the power system.[99]

P.1 SRAS contracts in SA

AEMO is required to procure SRAS consistent with the system restart standard (SRS).

AEMO has contracts with two SRAS providers in SA.

Prior to establishing these contracts, AEMO modelled restoration scenarios to confirm that the SRAS procured would be capable of meeting the SRS.

P.2 Routine tests

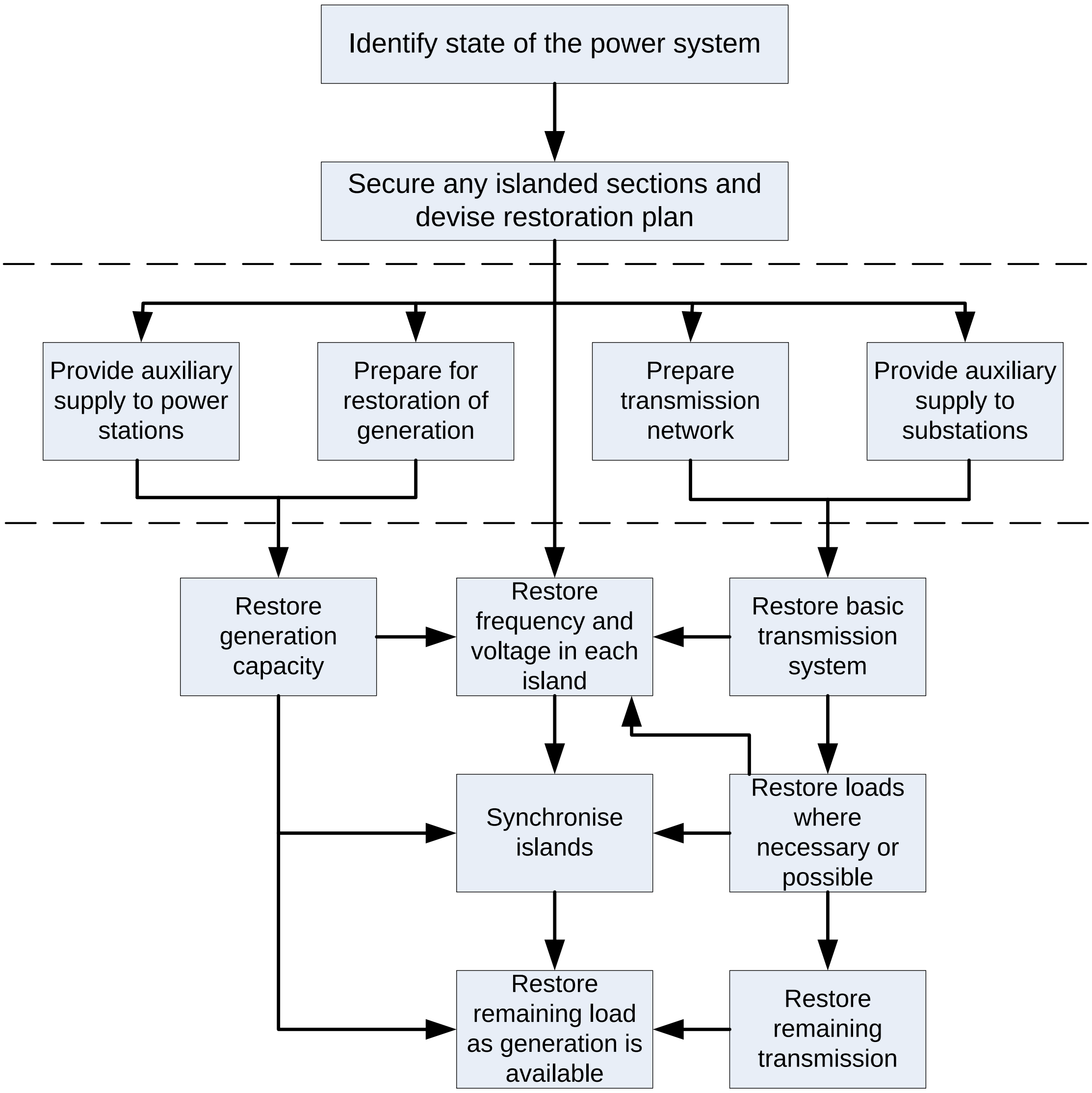
Part of AEMO's due diligence when procuring SRAS is to require the SRAS providers to demonstrate their restart capability in a test prior to entering into an SRAS contract, and then to demonstrate that capability throughout the term of the contract by testing at least annually.

Both of the SRAS procured for SA had been successfully tested less than six months prior to the 28 September 2016 Black System.

- AEMO witnessed Origin successfully perform a restart test on 21 May 2016. Origin demonstrated that it could use a small generating unit to restart a larger generating unit within the same power station without using any power supply from the network. During this test, a section of the ElectraNet network was de-energised and isolated to provide a restart path from the small unit to the larger unit. It was then re-energised by QPS. All CBs operated as expected during this test.
- AEMO witnessed Engie successfully perform a restart test on 19 April 2016. Engie demonstrated that it could restart its main generating unit without using any electricity supply from the network. This test included the energising of a 50 km 132 kV transmission line.

[99] Further information on SRAS is available on AEMO's website at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Ancillary-services/System-restart-ancillary-services-guidelines.

APPENDIX Q. OVERVIEW OF THE RESTORATION PROCESS



Q.1 Secure and make safe the power system

The initial task after a major system disturbance is to identify the state of the power system and to determine the extent of the disturbance. AEMO, in conjunction with the TNSPs and Generators, will determine:

- Which areas of the power system are blacked out.
- Which areas of the power system have islanded around.
- Any requirements for stabilising the island.
- Where are the separation points in the system and equipment that is not available.

After a major system disturbance, electrical islands can be formed. When the island(s) conditions have been assessed, then actions can be taken to stabilise their operation. This may require additional load shedding or load reconnection to ensure adequate frequency and voltage control within the surviving island.

Once any islanded generation has been stabilised, AEMO, in conjunction with the TNSPs, will determine an appropriate process to restore the power system. The plans may be in accordance with the Regional Restart Procedure, or the plans may require modification to take into account the state of power system.

Q.2 Prepare the system for load restoration

The initial stage of load restoration will be to energise power station auxiliaries, by using either SRAS or any on-line generation.[100] Such an arrangement requires express transmission corridors to be established between the start-up generation sources and auxiliaries of receiving power stations.

NSPs will need to first disconnect all circuits and then re-energise transmission network with adequate stable load necessary for effective voltage and frequency control, to establish the corridor. The priority is therefore not to reconnect consumer load, but to build sufficient network such that, when offline generating units becomes available, loads can be restored efficiently.

Q.3 Load restoration

Once transmission corridors have been established with auxiliary supply restored to all accessible power stations, the restoration of the remaining network and loads will depend on the availability of generation and the ability of the NSPs to restore the network. A major factor here will be staff availability, accessibility, and workload.

It is essential that, as generation capacity is made available, suitable transmission elements should be in place.

[100] Including generation in other regions via interconnectors.

APPENDIX R. RESTORATION DETAILS

Table 22 Restoration sequence of events – Main SA network

Time	Event
28 September	**Initial actions**
16:19 (T+44s)	Confirmed SA Black System with ElectraNet.
16:24 (T+6min)	Declared Black System condition for SA region.
16:25 (T+7min)	SA Market suspension declared. System separation constraints invoked to ensure accurate inputs for the remainder of the NEM. Automatic Generation Control (AGC) re-configured to stabilise frequency for the remainder of the network.
16:30 (T+12min)	Based on network conditions at this time, AEMO developed a restoration strategy in conjunction with ElectraNet and Generators with SRAS contracts. This included the following restoration plans to proceed in parallel: • To establish a corridor from Victoria and supply auxiliary supplies to SA power stations and high priority loads determined by ElectraNet. • To provide auxiliary supplies to power stations from QPS.
16:32 (T+14min)	Activated SRAS contract with QPS.
	Restart Sequence
16:37 (T+19min)	Requested QPS Unit 1 to come on at minimum load under SRAS.
17:10 (T+52min)	QPS start initiated and switching commenced.
17:13 (T+55min)	Torrens Island Power Station house load supplied from QPS unit.
18:43 (T+2h 25min)	Torrens Island house supplies were changed over to supplies from interconnector and QPS unit shutdown to allow connection to the interconnected system.
	Restart from Victoria
17:23 (T+1h 5min)	South East substation was energised from Victoria via the Heywood – South East No.2 275 kV transmission line. South East No.2 275 / 132 kV transformer energised.
17:33 (T+1h 15min)	Tailem Bend substation was energised via the South East – Tailem Bend No. 2 275 kV transmission line.
17:52 (T+1h 34 min)	South East SVCs energised.
18:06 (T+1h 48min)	Tungkillo substation was energised via Tailem Bend – Tungkillo 275 kV transmission line.
18:09 (T+1h 51 min)	Para substation was energised via Tungkillo – Para 275 kV transmission line.
18:18 (T+1h 59 min)	Para SVCs 1 and 2 were energised in service to provide voltage support.
18:21 (T+2h 3 min)	Para SVC 1 tripped. South East SVC 1 and 2 tripped.
18:28 (T+2h 10min)	Torrens Island East 275 kV busbar energised via Para – Torrens Island 275 kV transmission line.
18:32 (T+2h 14 min)	South East SVC 1 in service.
18:42 (T+2h 24min)	South East – Heywood No.1 transmission line in service.
18:52 (T+2h 34 min)	South East SVC 2 in service.
18:59 (T+2h 41min)	South East – Tailem Bend No.2 275 kV transmission line in service.
19:00 (T+2h 42min)	Transmission corridor from Victoria was established through to the Adelaide and CBD area and load restoration commenced. It was decided not to attempt to rebuild the network north of Adelaide due to advice of major transmission network damage.
19:01 (T+2h 43min)	South East – Mt Gambier – Blanche 132 kV transmission lines in service.
19:06 (T+2h 48min)	Tailem Bend – Cherry Gardens – Torrens Island 275 kV transmission lines in service.
19:07 (T+2h 49min)	Para – Magill 275 kV transmission line in service.
19:09 (T+2h 51min)	Cherry Gardens – Happy Valley 275 kV transmission line in service.
19:16 (T+2h 58min)	Happy Valley – Magill transmission line in service. This completed a loop between Torrens Island and Para 275 kV.
19:18 (T+3h)	Magill – Burnside 66 kV line in service.
19:29 (T+3h 11min)	Happy Valley – Seacombe – Oakland No.1 and No.2 66 kV lines in service.
19:31 (T+3h 13min)	Para – Parafield Gardens West – Pelican Point – Le Fevre – Torrens Island B 275 kV transmission lines in service.

Time	Event
19:35 (T+3h 17min)	Happy Valley – Morphett Vale East – Cherry Gardens 275 kV transmission line in service.
19:46 (T+3h 28min)	Torrens Island A – Northfield 275 kV transmission line in service.
19:48 (T+3h 30min)	Torrens Island A – Magill 275 kV transmission line in service.
19:50 (T+3h 32min)	Pelican Point gas turbine transformer energised. Auxiliary supply restored to Pelican Point Power Station.
19:54 (T+3h 36min)	Tungkillo – Mt Barker – Cherry Gardens 275 kV transmission line in service.
19:55 (T+3h 37min)	QPS units 1–4 in service.
20:06 (T+3h 48min)	Tailem Bend – Mobilong – Murray Bridge / Hahndorf Pumps No.2 132 kV transmission line in service.
20:43 (T+4h 25min)	Magill – East Terrace 275 kV transmission line in service.
20:47 (T+4h 29min)	South East – Snuggery 132 kV transmission line in service.
20:58 (T+4h 40min)	Torrens Island Power Station A2 generating unit in service.
21:23 (T+5h 5min)	Tailem Bend – Keith – Kincraig 132 kV transmission line in service.
21:34 (T+5h 16min)	Northfield – Kilburn – Torrens Island A 275 kV transmission line in service.
22:02 (T+5h 44min)	Torrens Island Power Station A4 generating unit in service.
22:05 (T+5h 47min)	Pelican Point Power Station gas turbine generating unit 1 in service.
22:08 (T+5h 50min)	Snuggery Power Station in service.
23:10 (T+6h 52min)	Pelican Point Power Station steam generating unit in service.
23:11 (T+6h 53min)	Para – Robertstown 275 kV transmission line in service.
23:31 (T+7h 31min)	Torrens Island Power Station B1 generating unit in service.
23:52 (T+7h 34min)	Tungkillo – Robertstown 275 kV transmission line in service.
29 September	**Conclusion of Black System condition**
02:40 (T+10h 22min)	Torrens Island Power Station B3 generating unit in service.
12:15 (T+19h 57min)	Davenport – Bungama 275 kV line was re-energised after line patrol. Allowing some electricity to be restored in the northern region.
18:25 (T+1d 2h 7min)	AEMO advised that that a Black System condition in the SA region was no longer current. AEMO gave clearance to restore the last load block in SA. AEMO notified that the Spot Market would continue to be suspended.
10 October 2016 13:40 (T+11d 21h 22min)	Davenport – Belalie 275 kV line
12 October 2016 19:15 (T+13d 2h 57min)	Davenport – Mt Lock 275 kV line.
Not yet restored, estimated several months	Davenport – Brinkworth 275 kV line

Table 23 Restoration sequence of events – Port Lincoln area

Time	Event
28 September	
(TBC) 19:15 (T+2h 57min)	Port Lincoln No. 1 & 2 generating units in service
(TBC) 20:00 (T+3h 42min)	Port Lincoln No. 3 generating unit in service
29 September	
00:53 (T+8h 35min)	Port Lincoln units 1 &2 trip. Port Lincoln unit 3 shut down
30 September	
10:25 (T+18h 7min)	Port Lincoln No. 3 generating unit in service.
15:06 (T+22h 48min)	Following several trips, Port Lincoln No 3 generating unit back in service.
20:50 (T+1d 4h 32min)	Port Lincoln No. 3 unit shut down
21:56 (T+1d 5h 38min)	Port Lincoln – Yadnarie 132 kV line placed in service, connecting Port Lincoln area to remainder of the SA network

APPENDIX S. GENERATION RESTORATION

Figure 84 QPS MW output during restoration

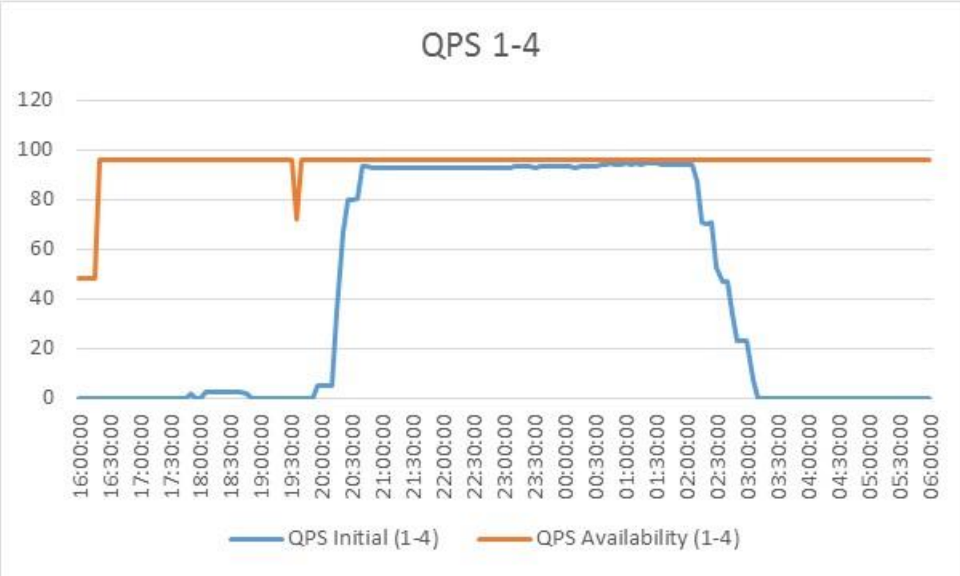


Figure 85 TIPS A2 Generating Unit MW output during restoration

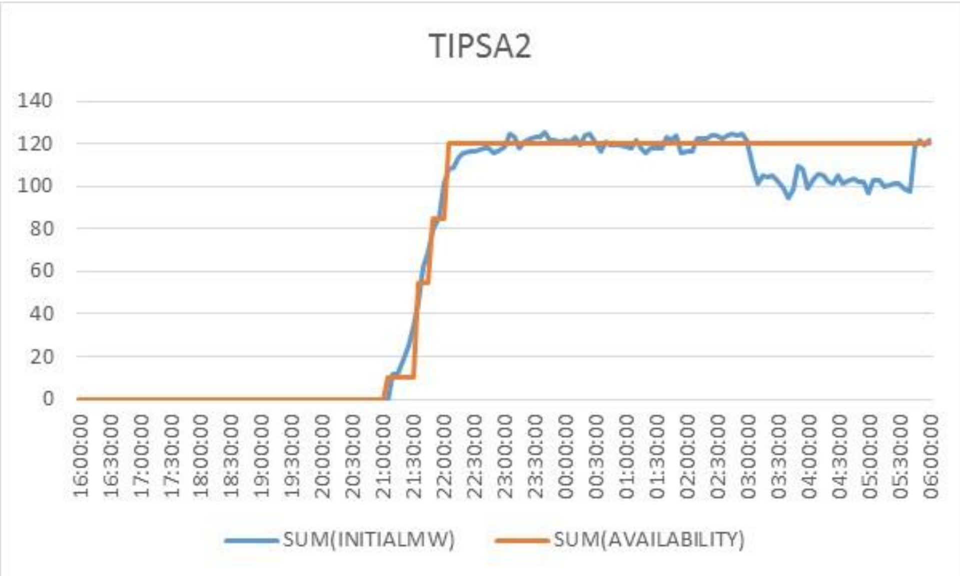


Figure 86 TIPS A4 Generating Unit MW output during restoration

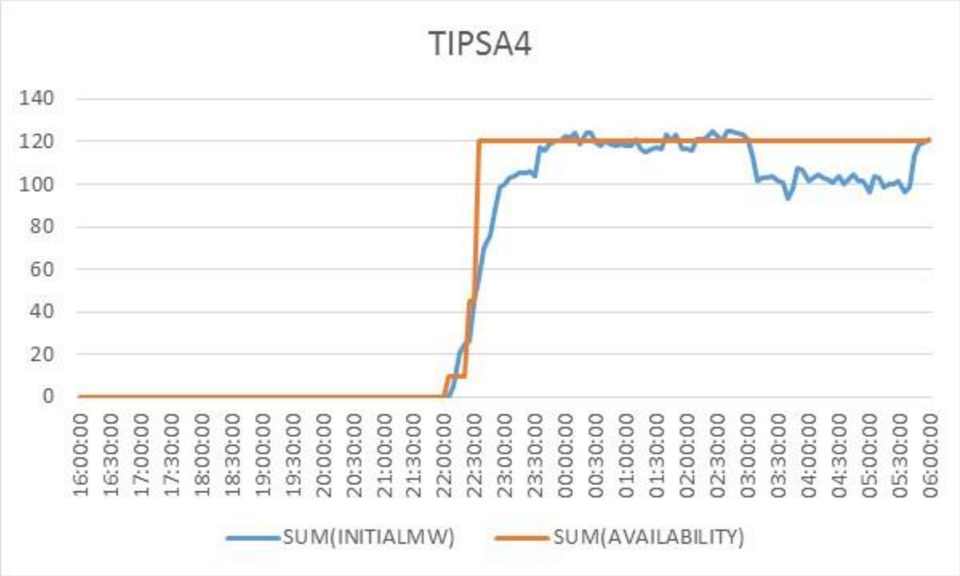
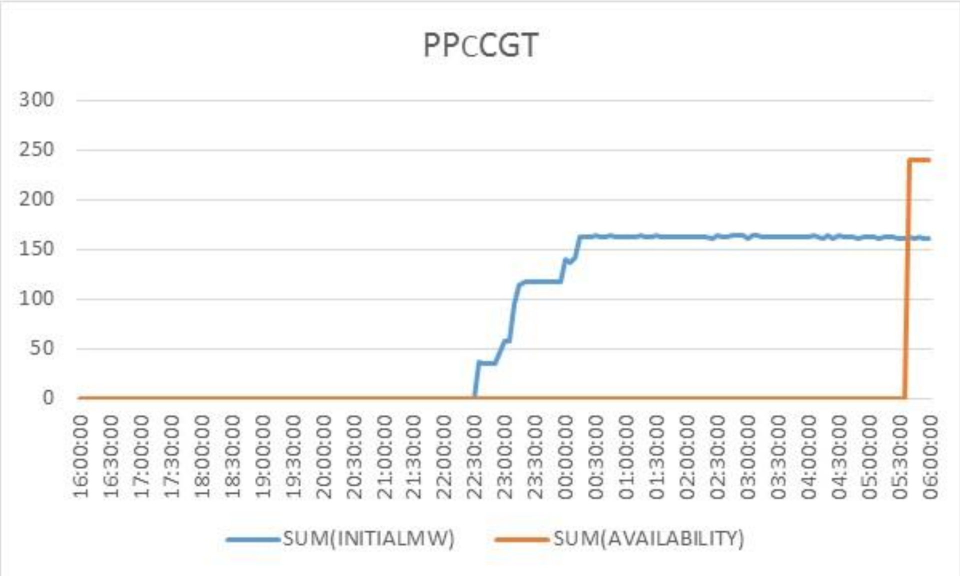


Figure 87 Pelican Point Power Station MW output during restoration



APPENDIX T. MARKET INFORMATION

T.1 AEMO market notices

Below are the market notices issued during the Black System event up until "clearance to restore the last load block". Additional Market Notices can be accessed via AEMO's website.[101]

Table 24 AEMO market notices

Date	Time	Action	Summary
28/09/16	16:25	Market Notice 54985 issued – SA Black System.	Advise market of 'Black System'.
28/09/16	16:28	Market Notice 54987 issued – AEMO declares the spot market to be suspended in SA.	Suspend Spot market in SA.
28/09/16	16:32	Market Notice 54989 issued – Determination of the spot price in the SA region.	Using Market suspension Default Pricing Schedule in SA.
28/09/16	16:53	Market Notice 54994 issued – AEMO has become aware of the following circumstance(s) with respect to the SA power system.	More specific details, i.e. Lightning storm and ~1,900 MW shed in SA.
28/09/16	18:18	Market Notice 55001 issued – Update to SA system black restoration.	18:13 the restoration is proceeding.
28/09/16	20:05	Market Notice 55010 issued – Update to SA system black restoration.	Power is being restored via Vic–SA Heywood I/C.
28/09/16	20:14	Market Notice 55017 issued – Update to SA system black restoration.	300MW restored in the SA region.
28/09/16	22:15	Market Notice 55021 issued – Update to SA system black restoration.	700MW restored in the SA region.
29/09/16	05:43	Market Notice 55029 issued – Update to SA system black restoration.	900 MW restored in the SA region.
29/09/16	05:49	Market Notice 55030 issued – Inter-Regional Transfer Limit Variation Murraylink – 29/09/16	Murraylink not following the value determined by NEMDE – constraint invoked.
29/09/16	07:09	Market Notice 55031 issued – Cancellation – Inter-Regional Transfer Limit Variation Murraylink – 29/09/16	Murraylink following the value determined by NEMDE – constraint revoked.
29/09/16	10:04	Market Notice 55033 issued – SA Market suspension update.	More details on Market suspension Default Pricing Schedule in SA.
29/09/16	11:35	Market Notice 55035 issued – Update to SA restoration.	AEMO update on the forward plan in SA.
29/09/16	13:39	Market Notice 55036 issued – Update to SA Spot Market suspension.	Continuation of Market suspension Default Pricing Schedule in SA.
29/09/16	15:05	Market Notice 55037 issued – Cancellation of following planned outages in Victoria region from 05/10/2016 to 07/10/2016	Moorabool to Tarrone 500 kV line, Heywood to Tarrone 500 kV line and Heywood No.1 500 kV busbar outages cancelled.
29/09/16	18:29	Market Notice 55046 issued – AEMO advises that a Black System condition in the SA region is no longer current.	Clearance to restore the last load block in SA. Black System condition in the SA region is no longer current. Spot Market still suspended.

[101] Available at: http://www.aemo.com.au/Market-Notices.

T.2 AEMO Media Centre statements

1. “Media Statement – South Australia”, issued 1732 hrs on 28 September 2016. Available at: http://www.aemo.com.au/Media-Centre/Media-Statement---South-Australia.
2. “Media Statement – South Australia – update as at 22:00 AEST”, issued at 2258 hrs on 28 September 2016. Available at: http://www.aemo.com.au/Media-Centre/Media-Statement---South-Australia-Update.
3. “Media Statement 3 – South Australia Update 10:30 am”, issued at 1052 hrs on 29 September 2016. Available at: http://www.aemo.com.au/Media-Centre/Media-Statement-3---South-Australia-Update.
4. “South Australia Electricity Update”, issued at 1424 hrs on 2 October 2016. Available at: http://www.aemo.com.au/Media-Centre/Media-statement---SA-electricity-update-2-Oct-2016.
5. “Resumption of spot market in South Australia”, issued 2103 hrs on 11 October 2016. Available at: http://www.aemo.com.au/Media-Centre/Media-statement---South-Australian-suspension-revoked.

APPENDIX U. PROGRESS OF LOAD RESTORATION

The diagrams below provide an overview of the load restoration process in the Adelaide metropolitan area.

The amount of load restored is calculated based on the load on the major 275/66 kV transformers in the major substations that that feed each of the different areas:

- Northern suburbs – Para and Parafield Gardens West.
- Southern suburbs – Happy Valley and Morphet Vale East.
- Eastern suburbs – Magill, East Terrace and Northfield.
- Western suburbs – Le Fevre and Torrens Island.

Figure 88 Two hours after the Black System, no load had been restored

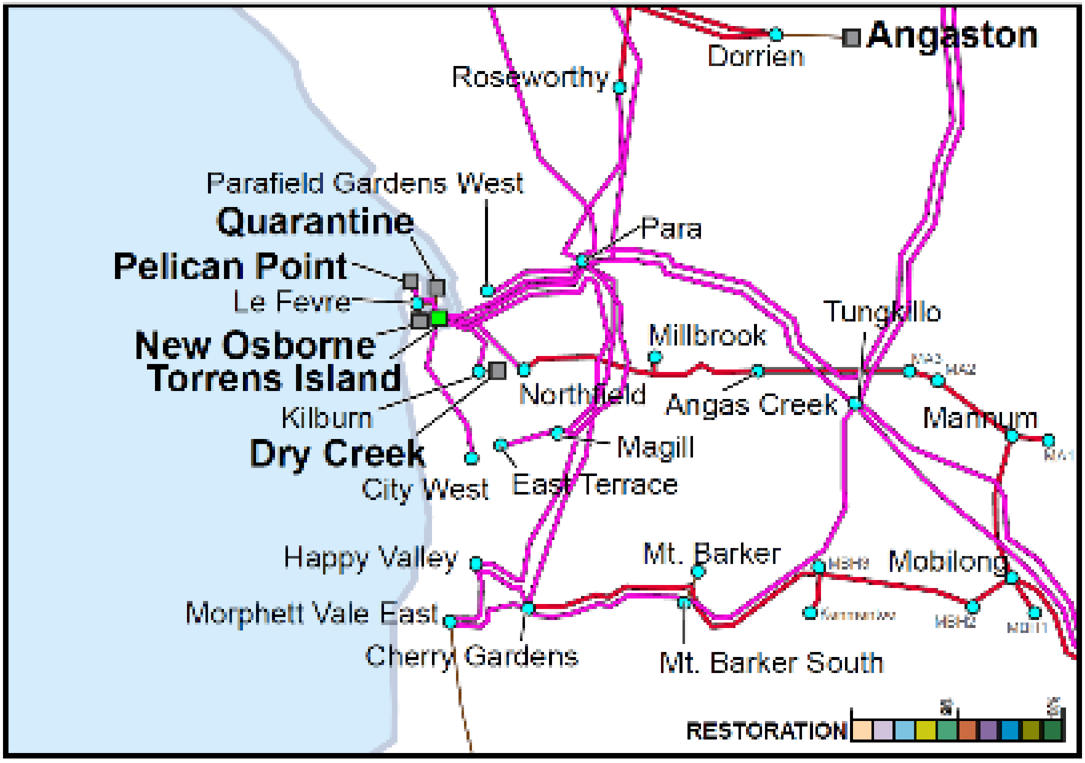


Figure 89 Percentage of load restored after 3 hours

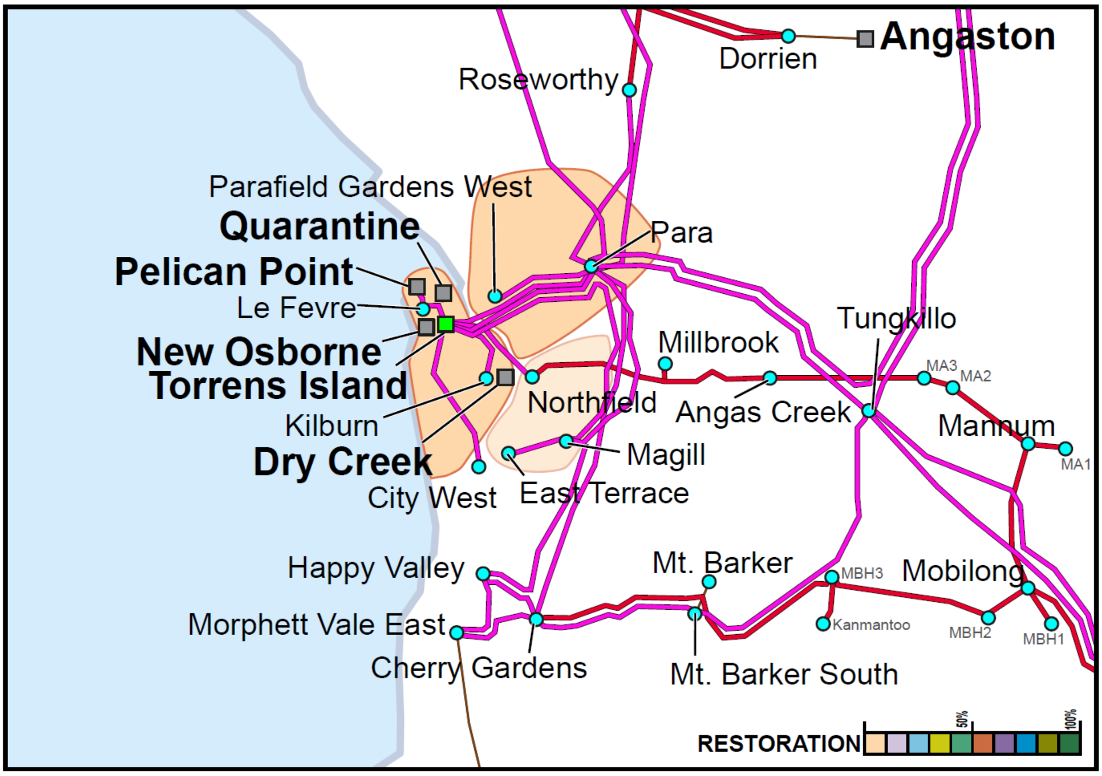


Figure 90 Percentage of load restored after 4 hours

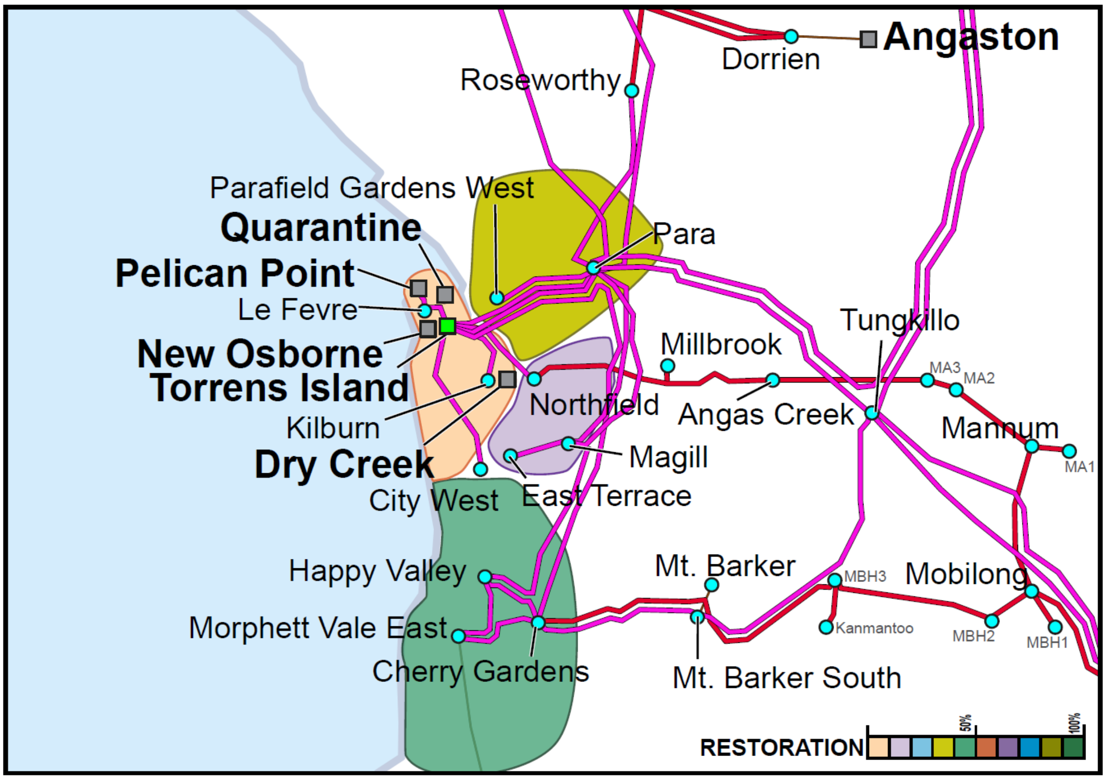


Figure 91 Percentage of load restored after 5 hours

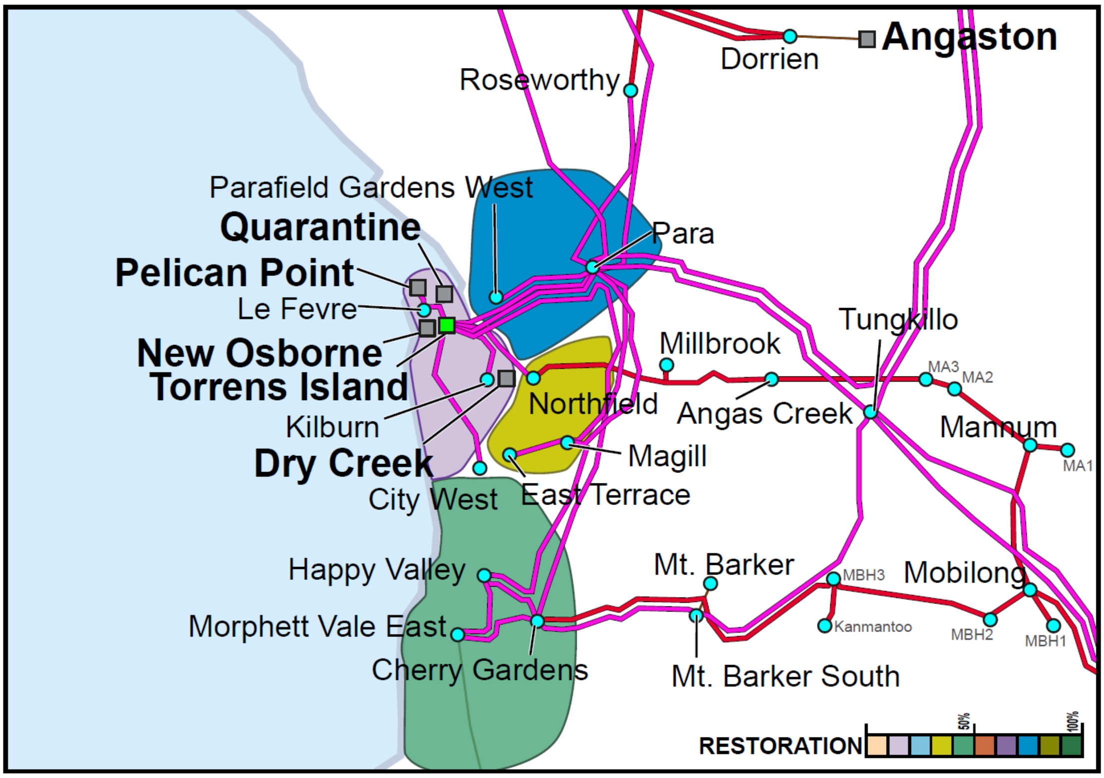


Figure 92 Percentage of load restored after 6 hours

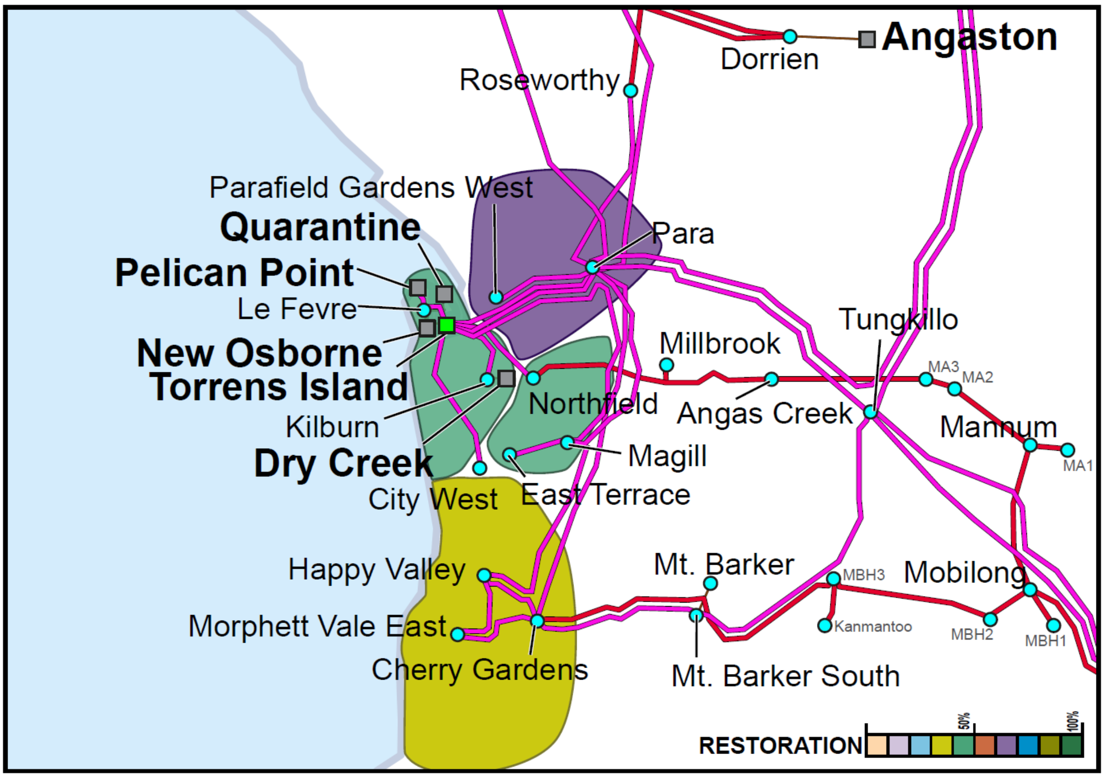
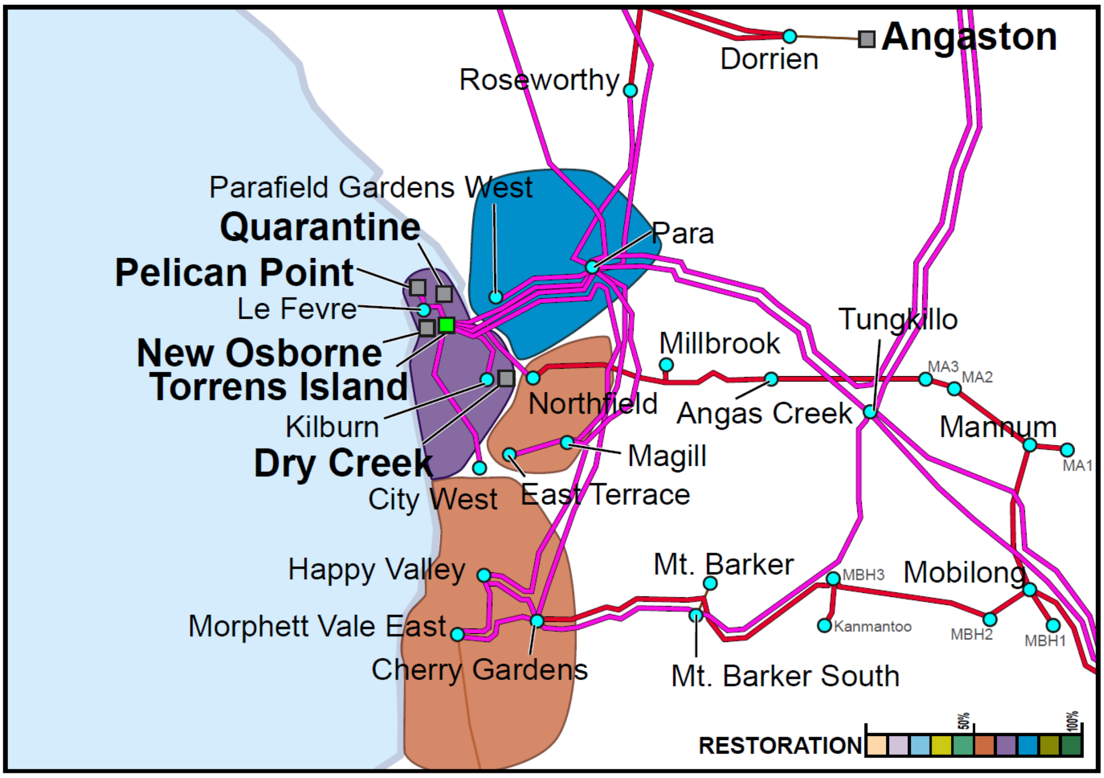


Figure 93 Percentage of load restored after 7 hours



APPENDIX V. ADVICE FROM ELECTRANET REGARDING DESIGN RATING OF TRANSMISSION LINES

With regard to the design ratings of the lines involved in the Black System event, ElectraNet has advised, subsequent to this event, the following:

Feeder	Capability of towers (original structures) See Notes 1, 2 & 3
Davenport – Mount Lock / Davenport – Belalie 275 kV (Double circuit) (F1919/F1920)	46m/sec [165 km/h]
Templers West – Brinkworth 275 kV (F1911)	28.6 m/sec [106 km/h]
Brinkworth – Davenport 275 kV (F1910)	28.6 m/sec [106 km/h]

Notes:

1. The original design specifications for each feeder differ due to changes in design philosophy that have occurred in Australian over the past 50 years. To simplify rating comparisons of each feeder, wind models representative of synoptic/downburst/tornado events defined in AS/NZS 7000-2016 “Overhead Line Design – Detailed Procedures” are used.
2. The design ratings are relevant for the tower performance at the specific failure sites. A review of the duty of the remaining structures within the whole feeder is required to ascertain the rating for that feeder.
3. The wind speed ratings used for transmission design are derived from a 3-second gust wind speed over a defined gust width in accordance with AS/NZS Overhead Line Design and AS1170.2 Wind Loading. This is not the same as an average wind speed across a whole storm front.