BLACK SYSTEM SOUTH AUSTRALIA 28 SEPTEMBER 2016

Published: **March 2017**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared this final report of its review of the Black System in South Australia on Wednesday 28 September 2016, under clauses 3.14 and 4.8.15 of the National Electricity Rules (NER).

This report is based on information available to AEMO as of 23 March 2017.

Disclaimer

AEMO has been provided with data by Registered Participants as to the performance of some equipment leading up to, during, and after the Black System. In addition, AEMO has collated information from its own systems.

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:

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- 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
AWEFS	Australian Wind Energy Forecasting System
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
DER	Distributed Energy Resources
DFS	Demand Forecasting System
DI	Dispatch interval
DNSP	Distribution Network Service Provider
DVAR	Dynamic Volt-Amp Reactive
EMMS	Electricity Market Management System
EMT	Electromagnetic transient
EMTDC	Electromagnetic transients including DC
ESCOSA	Essential Services Commission of South Australia
FACTS	Flexible AC Transmission Systems
FCAS	Frequency control ancillary services
FPSS	Future Power System Security (program)
GIC	Geomagnetic Induced Current
GSMG	Generating System Model Guidelines
GT	Gas Turbine
HV	High Voltage
HVDC	High Voltage Direct Current
HSM	High-Speed Monitor
HYTS	Heywood Terminal Station
I/S	In Service
LBSP	Local Black System Procedure
LOS	Loss of Synchronism
LV	Low Voltage
LVRT	Low Voltage Ride Through

Abbreviation	Expanded name
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEMOC	National Electricity Market Operations Committee
NER	National Electricity Rules
NERC	North-American Electric Reliability Corporation
NSP	Network Service Provider
OEM	Original equipment manufacturer
OPDMS	Operations and Planning Data Management System
O/S	Out of Service
PSCAD	Power System Computer Aided Simulation
PSS/E	Power System Simulator for Engineering
POD	Power Oscillation Damper
PSB	Power Swing Blocking
PSSWG	Power System Security Working Group
PTL	Port Lincoln
PV	Photovoltaic
QPS	Quarantine Power Station
RMS	Root mean square
RoCoF	Rate of Change of Frequency
RTDS	Real Time Digital Simulator
SA	South Australia
SAPN	SA Power Networks
SCADA	Supervisory Control and Data Acquisition
SCR	Short Circuit Ratio
SESS	South East Substation
SPAR	Single phase auto-reclosing
SPS	Special Protection Scheme
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

Abbreviation	Unit of Measure
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 is AEMO's final report into the Black System in South Australia (SA) on 28 September 2016. It contains all the information previously published, and highlighted information that has been updated or added since the previous report. Chapter 1 gives details about, and links for, the earlier reports.

This report is divided into the following sections:

- **Pre-event** – the status of the power system in SA prior to the Black System on 28 September 2016 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.
- **Recommendations** – for action proposed by AEMO as a result of this investigation.
- **Next Steps** – an outline of the broader work being undertaken by AEMO to address the challenges to power system security and reliability posed by the changing nature of the power system.

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

This is AEMO's final report about the sequence of events before, during, and after the South Australia (SA) region black system event on 28 September 2016 (Black System), in which some 850,000 SA customers lost electricity supply, affecting households, businesses, transport and community services, and major industries.

It consolidates all the information previously published in AEMO's three preliminary reports[1], adding further insights about the performance of the power system during this event, and risks identified, from AEMO's investigations and analysis.

This report also outlines actions taken since this event, and ongoing actions from before and after the event, to collectively mitigate the risk of similar major supply disruptions occurring in SA and the rest of the National Electricity Market (NEM).

What challenges and potential improvements has AEMO identified?

This report focuses on the specifics of the SA Black System event on 28 September 2016. It also highlights a number of challenges and valuable lessons relevant to improving power system security and customer supply reliability, particularly as the power system responds to extreme circumstances, as the NEM generation mix changes and Australia makes the transition to high levels of renewable energy sources.

The generation mix now includes increased amounts of non-synchronous and inverter-connected plant. This generation has different characteristics to conventional plant, and uses active control systems, or complex software, to ride through disturbances. With less synchronous generation online, the system is experiencing more periods with low inertia and low available fault levels, so AEMO is working with industry on ways to use the capability of these new types of power generation to build resilience to extreme events.

As the generation mix continues to change across the NEM, it is no longer appropriate to rely solely on synchronous generators to provide essential non-energy system services (such as voltage control, frequency control, inertia, and system strength). Instead, additional means of procuring these services must be considered, from non-synchronous generators (where it is technically feasible), or from network or non-network services (such as demand response and synchronous condensers).

The technical challenges of the changing generation mix must be managed with the support of efficient and effective regulatory and market mechanisms, to ensure the most cost-effective measures are used in the long-term interest of consumers.

AEMO is continuing to work in association with its stakeholders to resolve these challenges, including through the established Future Power System Security (FPSS) program, and collaborative engagement with the Australian Energy Market Commission (AEMC) and the Council of Australian Governments (COAG) Independent Review into the Reliability and Security of the NEM, led by Dr Alan Finkel.

AEMO has also begun work with the Australian Renewable Energy Authority (ARENA) and others on proof-of-concept trials of promising new technologies, starting with use of the new Hornsdale Stage 2 wind farm to provide grid stabilisation services. These projects can deliver engineering solutions to make the grid more resilient and protect customer supply as the transformation of Australia's energy system continues.

[1] Preliminary reports are available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports.

What happened on 28 September 2016?

This summary of events is based on the findings of all AEMO's investigations since the Black System event, and information published by other organisations.

On Wednesday 28 September 2016, tornadoes with wind speeds in the range of 190–260 km/h occurred in areas of South Australia.[2] 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.

The damage to these three transmission lines caused them to trip[3], and a sequence of faults in quick succession resulted in six voltage dips on the SA grid over a two-minute period at around 4.16 pm.

As the number of faults on the transmission network grew, nine wind farms in the mid-north of SA exhibited a sustained reduction in power as a protection feature activated. For eight of these wind farms, the protection settings of their wind turbines allowed them to withstand a pre-set number of voltage dips within a two-minute period. Activation of this protection feature resulted in a significant sustained power reduction for these wind farms. A sustained generation reduction of 456 megawatts (MW) occurred over a period of less than seven seconds.

The reduction in wind farm output caused a significant increase in imported power flowing through the Heywood Interconnector. Approximately 700 milliseconds (ms) after the reduction of output from the last of the wind farms, the flow on the Victoria–SA Heywood Interconnector reached such a level that it activated a special protection scheme that tripped the interconnector offline.

The SA power system then became separated ("islanded") from the rest of the NEM. Without any substantial load shedding following the system separation, the remaining generation was much less than the connected load and unable to maintain the islanded system frequency. As a result, all supply to the SA region was lost at 4.18 pm (the Black System).[4] AEMO's analysis shows that following system separation, frequency collapse and the consequent Black System was inevitable.

Immediately following the Black System, AEMO and ElectraNet first assessed the state of the transmission network, then ElectraNet made safe the damaged transmission lines that may have been presenting a potential threat to public safety.

After assessing what sections of the network were safe to energise, a system restart plan began at 4.30 pm, including restart capability from one of two contracted SA system restart ancillary service (SRAS) generators, and supply from Victoria via the Heywood Interconnector.

The first customers had power restored by 7.00 pm on 28 September. About 40% of the load in SA capable of being restored had been restored by 8.30 pm, and 80 to 90 % had been restored by midnight. The remaining load was gradually restored as fallen transmission lines were bypassed, and all customers had supply restored by 11 October 2016.

Within minutes of the event, AEMO declared the NEM suspended in the SA region. The market suspension was not immediately lifted when the Black System ended, due to continuing uncertainties in power system operations. Twelve days later, on 11 October 2016, the SA government advised AEMO at 5.48 pm that its direction for suspension of the market had been revoked, and AEMO lifted the suspension at 10.30 pm.

While the market was suspended:

- AEMO continued to manage power system operations in SA. This included, from 3 October 2016, reclassifying the loss of multiple wind farms as a credible contingency event and placing a constraint equation on the output of these wind farms until the pre-set levels for their special protection scheme were increased. No wind farms are still subject to the constraint equation.

[2] 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/.

[3] When a transmission line is damaged there is a short circuit (fault) and the line must be disconnected to protect the remainder of the system (known as a "trip"). However disconnection cannot occur instantaneously and so for a fraction of a second there is voltage dip (disturbance).

[4] The supply demand imbalance was in the order of 1,000 MW, for a regional demand of 1,826 MW.

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

What conclusions have come from AEMO's investigations?

From its analysis of the Black System event, many of AEMO's conclusions provide valuable guidance for improving the management of extreme conditions in SA:

- Access to correct technical information about grid-connected equipment is critical for system security.
- Wind turbines successfully rode through grid disturbances. It was the action of a control setting responding to multiple disturbances that led to the Black System. Changes made to turbine control settings shortly after the event has removed the risk of recurrence given the same number of disturbances.
- Had the generation deficit not occurred, AEMO's modelling indicates SA would have remained connected to Victoria and the Black System would have been avoided. AEMO cannot rule out the possibility that later events could have caused a black system, but is not aware of any system damage that would have done this.
- The following factors must be addressed to increase the prospects of forming a stable SA island and avoiding a Black System:
  - Sufficient inertia to slow down the rate of change of frequency and enable automatic load shedding to stabilise the island system in the first few seconds. This will require increases in SA inertia under some conditions, as well as improvements to load shedding systems combined with reduced interconnector flows under certain conditions.
  - Sufficient frequency control services to stabilise frequency of the SA island system over the longer term. This will require increases in local frequency control services under some conditions.
  - Sufficient system strength to control over voltages, ensure correct operation of grid protection systems, and ensure correct operation of inverter-connected facilities such as wind farms. This will require increases in local system strength under some conditions.

As noted in the recommendations chapter, AEMO is working with stakeholders to identify the best ways to address each of these requirements.

A number of factors investigated by AEMO were found to have little or no material effect on the event:

- Trips of wind turbines due to high wind speed.
- Operation of the five gas generators on-line at the time.
- Performance of the Murraylink interconnector.
- Settings of the relays that tripped the interconnector.
- Settings of powerline protection relays.
- Static Var Compensators (SVCs).

AEMO's key conclusions related to system restoration are:

- 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.
- The failure of the Quarantine Power Station (QPS) SRAS was due to the switching sequence used. Measures have been put in place and tested to remedy this.
- The Mintaro emergency diesel generator tripped soon after starting, but this did not delay the restoration process because the generator cannot by itself restore large generating units in the Torrens Island area. The cause has been addressed.

AEMO will work with the SA System Restart Working Group to learn from this event by identifying cost-effective measures to improve speed of restoration of supply to all areas without increasing risk.

The key conclusion related to the market suspension is that there is a lack of detailed procedures on how to operate the power system under extended periods of market suspension.

What does AEMO recommend?

While extreme events will occur from time to time, testing the wider resilience of the grid, this report recommends 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 the 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.

This report also outlines actions taken since this event, and ongoing actions from before and after the event, to collectively mitigate the risk of similar major supply disruptions occurring in SA. These actions have included:

- Changes by several wind farms in SA to the settings for the protective feature for multiple voltage disturbances.
- Introduction of restrictions on Heywood Interconnector flow to ensure the rate of change of frequency in SA for the unexpected loss of the Heywood Interconnector alone does not exceed 3 Hz/sec.
- Requirement for a minimum number of on-line synchronous generators in SA.

AEMO's recommendations are summarised below. Of the 19 recommendations:

- Seven are new in this report (recommendations 1, 4, 5, 8, 9, 10, and 11 below).
- Three have already been implemented (recommendations 2, 13, and 14 below, addressing more rigorous weather warning monitoring, and improvements to SRAS testing).
- Work has begun on another eight recommendations (3, 4, 12, 15, 16, 17, 18, and 19).
- AEMO plans to complete the remaining recommendations by December 2017 (noting that two recommendations relate to potential changes to the National Electricity Rules (NER), and a number of recommendations involve review, consultation and engagement processes with other organisations and bodies).

Chapter 7 has more detail on these recommendations, including relevant conclusions from AEMO's investigations and analysis.

Table 1 Summary of recommendations

1	AEMO to propose to ESCOSA changes to generator licensing conditions, and also to request similar changes to the NER, to address deficiencies in performance standards identified through this investigation.
2	AEMO to put in place more rigorous processes to monitor weather warnings for changes to forecasts, to trigger reassessment of reclassification decisions where relevant.
3	AEMO to review and implement, following consultation, a more structured process for reclassification decisions when faced with power system risks due to extreme wind speeds.
4	AEMO to assess options for improved forecasting of when wind speeds will exceed protection settings on wind turbines, which would lead to 'over-speed cut-outs'.
5	AEMO to consider development of a new generator reclassification process to manage generator 'type' risks[5], including how information about potential risks will be sought, and the most appropriate methods to manage power system security during such a generator reclassification.
6	AEMO to work with ElectraNet to determine the feasibility of developing a special protection scheme to operate in response to sudden excessive flows on the Heywood Interconnector, and to initiate load shedding with a response time fast enough to prevent separation.
7	AEMO to modify existing transfer limits on the Heywood Interconnector to take into account the fact that the largest credible generator contingency under conditions of high wind generation is greater than previously assumed.
8	AEMO to modify operational procedures for SA island operation to: • Take into account the fact that, under islanded conditions, system strength may fall to a level where some wind farms might not be able to ride through credible voltage disturbances. • Ensure that maintenance of adequate system strength is incorporated into the transmission planning process in a more systematic manner.
9	AEMO to support ElectraNet to identify and address any specific risks to the operation of protection systems due to the low levels of system strength that may be experienced if SA is islanded.
10	AEMO to support ElectraNet in reassessing control strategies to achieve very rapid switching of reactive plant to manage the risk of severe over voltages in SA that might occur due to large levels of under frequency load shedding following separation.
11	AEMO to review its reclassification procedures to address any remaining material risk due to multiple voltage disturbances, and to approach relevant Generators to review the feasibility of increasing plant limits for the maximum number of multiple voltage disturbances that can be tolerated over a 30-minute period.
12	AEMO, together with the South Australian System Restart Working Group, to review the system restart process in detail to determine efficiencies and to implement relevant recommendations from the Reliability Panel. These learnings will be shared across all Australian jurisdictions
13	Any differences between SRAS test plans and the restart process set out in a system restart plan and associated local black system procedures to be identified and explained by AEMO, to ensure the test simulates, as far as practicable, the conditions that will be encountered in a real restart situation
14	Similarly, where the restart procedure depends initially on starting a low voltage generator, the start of this generator alone to be tested on a regular basis, in addition to the annual test of the entire SRAS source
15	AEMO to develop detailed procedures for in power system operations during periods of market suspension, and identify if any NER changes are desirable to improve the process
16	AEMO to investigate a better approach to ensuring that the minimum stable operating levels of generating units are taken into account in the dispatch process
17	AEMO to review market processes and systems, in collaboration with participants, to identify improvements and any associated NER or procedure changes that may be necessary to implement those improvements
18	AEMO to develop a more structured process in consultation with participants to source and capture data after a major event in a timely manner and to co-ordinate data requests.
19	AEMO to investigate with participants the possibility of introducing a process to synchronise all high speed recorders to a common time standard.

[5] There are generating systems consisting of many mass-produced smaller generating units with, often, a particular model of generating unit common to a number of generating systems. Thus, a feature or fault for such a model could result in a large number of smaller generating units across multiple generating systems tripping simultaneously. As a result, AEMO may need to develop a new form of reclassification process to manage such risks.

Focus of this report

Building on the detailed third preliminary report published in December 2016, the preparation and publication of new and updated information in this final report focuses specifically on:

- Whether the actual performance of power system plant was consistent with:
  - The performance that would be expected, based on the relevant performance and system standards.[6]
  - Expected performance based on AEMO's dynamic power system models.
- Whether changes to access standards are desirable, in light of the risks highlighted by this event.
- Scenario studies, including:
  - Would the result have been different if wind farm generation had not reduced in output due to the low voltage protection feature?
  - What would have been the result if AEMO had decided to reclassify the loss of multiple transmission lines as a credible contingency on that day?
- Performance requirements for possible special protection schemes to prevent islanding of the SA region or to improve the likelihood of successful islanding.
- Reviewing the performance of SVCs at Para and South East sub-stations.
- Further investigation of the materiality of risks, including those:
  - Due to a transient reduction of output from multiple wind farms during fault conditions.
  - From high winds, or rapidly changing winds, in in areas of high wind farm concentration.
  - Of unnecessary impedance relay operations during this type of event.
  - Of over voltages in the SA transmission system due to load shedding or islanding conditions.
  - Of low system strength in the SA transmission system, following separation from the rest of the NEM.

Conclusion

AEMO has completed its investigations into the 28 September 2016 Black System in SA, and will continue to work closely with industry to implement all recommendations outlined in this report.

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

CONTENTS

TABLES

FIGURES

1. REPORT OBJECTIVES AND SCOPE

This is AEMO's final report on the South Australian (SA) black system event of 28 September 2016 (Black System). It sets out AEMO's understanding of:

- Details of the Black System, and the series of events that led to the Black System.
- 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 examines:

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

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

- **Preliminary 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.
- **Update 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.
- **Third Report** – published on 12 December 2016, titled *Black System South Australia 28 September 2016 – Third Report* and based upon information available up to 0900 hrs on Wednesday 7 December 2016.

All these reports are available on AEMO's website at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Market-notices-and-events/Power-System-Operating-Incident-Reports.

Updated or new information is highlighted through this report.

2. PRE-EVENT

This chapter outlines the state of the power system[7] in the period leading up to the events resulting in a Black System at 1618 hrs on 28 September 2016, which resulted in the loss of supply to all customers in SA (approximately 850,000 customer connections and 1,826 megawatts (MW)[8] of demand).

The information in this chapter is unchanged since AEMO published its previous report in December 2016, except where otherwise noted.

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.[9] 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.[10]
- 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.[11] This included comparisons between forecast and actual wind farm outputs to ensure accurate dispatch (see Appendix E.3). 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.[12] 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[13], 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.

[7] Appendix A illustrates the SA 275 kilovolt (kV) transmission network before the event. 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.

[8] This was given as 1,895 MW of demand 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.

[9] AEMO's sources of information include Weatherzone, the BOM, and Indji Watch (Global Positon and Tracking Systems Pty Ltd (GPATS)).

[10] 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.

[11] Under high wind speed or high ambient temperature conditions, wind generation can shut down to protect wind turbines from damage.

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

[13] 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.

- 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 forecast conditions (advice to AEMO of the existence of such risks is standard practice under clause 4.8.1 of the NER).[14] Under procedures in place at that time, AEMO would only reclassify the 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 transmission network service provider (TNSP).[15] AEMO did not keep details of design ratings for wind loadings, and relied upon TNSPs, as asset owners, to alert AEMO.
- AEMO understood that all wind turbines were capable of riding through credible faults, provided these faults were within the size and duration parameters specified in generator performance standards[16] that would have ensured they cleared within the maximum clearance times set out in the System Standards.[17] AEMO had not received any advice from the impacted Generators on their pre-set protection limits with respect to the number of faults in quick succession.

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.[18]

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 (such as a generating unit or transmission line) can be suddenly lost without system parameters breaching limits. These events are termed credible contingency events, because their occurrence is considered 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.

[14] See Appendix F.11 for further details on this requirement.
[15] For instance, during Cyclone Marcia in February 2015. For further details see AEMO. *NEM Event – Directions to Northern Queensland Generators during Tropical Cyclone Marcia – 20 February 2015*, 7 May 2015. Available at: https://www.aemo.com.au/media/Files/Other/reports/NEM%20Event%20%20Directions%20to%20Nth%20Queensland%20Gens%20%2020%20February%202015.pdf.
[16] See NER S5.2.5.5.
[17] The System Standards are detailed in Schedule 5.1a of the NER, specifically, clause S5.1a.8 of the NER.
[18] 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.

- Following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, 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.[19] Reclassification usually requires AEMO to apply additional constraints to the transmission network, and this can result in changes to 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[20] in SA was being supplied by a combination of thermal (synchronous) generation, wind generation, and imports from Victoria across both the alternating current (AC) Heywood Interconnector and the Murraylink direct current (DC) interconnection.

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

Figure 1 SA generation mix pre-event

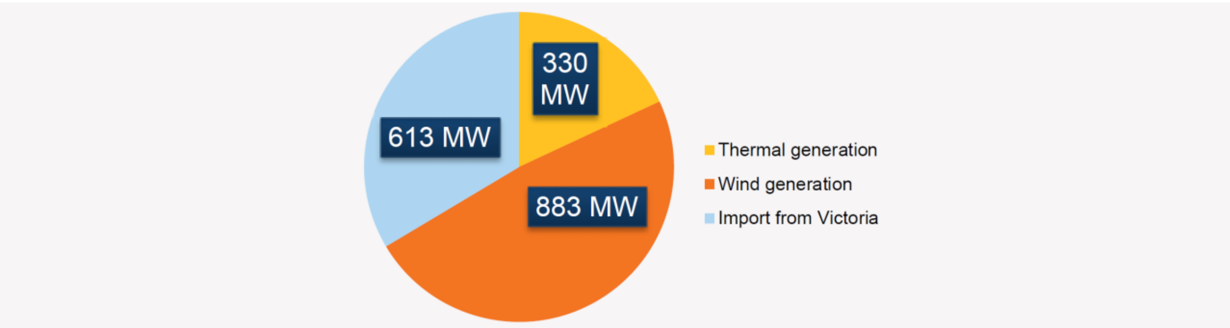


Table 2 sets out the output of the generators on-line at the time of the Black System, including the substation and lines they connect to. The combined inertia of the thermal generating units was around 3,000 megawatt seconds (MWs).

Table 2 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–Mayura–South East Snuggery–Blanch
Hallett WF	Wind	38	Canowie	Canowie–Mt Lock Canowie–Robertstown
Hallett Hill WF	Wind	42		

[19] See Appendix F for definitions.

[20] 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
Hornsdale WF	Wind	86	Mt Lock	Mt Lock–Davenport Mt Lock–Canowie
Lake Bonney 1 WF	Wind	77	Mayura	Mayura–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		
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 2 comprises Snowtown North and Snowtown South wind farms.

As Figure 2 shows, there were significant variations in wind generation in the hour before the event, including a significant reduction at about 1540 hrs.

Figure 34 in Appendix E.2 shows that general wind speeds in the Snowtown area peaked above 90 km/hr around that time. The output of the wind farms in this immediate area was reduced, probably due to operation of the over-speed protection. The wind speed dropped away quickly and the output of these wind farms began to increase around 1605 hrs.

The subsequent BOM report[21] indicates that the storm front continued to move eastwards, and the winds began to peak in the vicinity of the wind farms near Hallett. Immediately prior to events leading to the Black System, the output of some of these wind farms was falling, again probably due to operation of the over-speed protection.

If this event had not happened, it is possible that output of these wind farms could have continued to fall. To understand the significance of this, AEMO has undertaken a scenario study assuming:

- The loss of the four 275 kilovolt (kV) transmission lines damaged in the storm.
- No sustained power reduction due to the operation of the protective feature triggered by multiple voltage disturbances, but a further 200 MW reduction in wind generation due to operation of the over-speed protection.

The simulation results for this scenario have indicated that the SA power system would have remained stable and separation from the rest of the NEM would not have occurred. Detailed results of this simulation are in Section 3.5.1 and Appendix M.2.[22]

These unusually large and rapid variations in wind generation can result in flow on the Heywood Interconnector exceeding its secure limit but not reaching the limit for stable operation. Normal dispatch

[21] BOM. *Severe thunderstorm and tornado outbreak South Australia 28 September 2016. Available at:* http://www.bom.gov.au/announcements/sevwx/sa/Severe_Thunderstorm_and_Tornado_Outbreak_28_September_2016.pdf.

[22] The above information is additional to that provided in the Third Report. It has been added to provide more explanation of the reasons for the variability of the wind generation prior to the event and the reason that AEMO does not believe that it was a critical issue for this event.

processes then act to increase dispatch of local SA generation or Murraylink to bring the Heywood Interconnector flow back within the secure limit.

For instance, the sharp fall in wind generation at around 1540 hours resulted in flow on the Heywood Interconnector peaking to 585 MW (about 160 MW above the secure limit at that time). The central dispatch system then increased dispatch of generation to bring the flow back to the secure limit within 15 minutes.

While the intermittency of the wind was not a material factor in the Black System event itself, its impact was greater than expected and action has been recommended in Chapter 7 to improve AEMO's ability to forecast the impact of over-speed protection during high wind conditions.

Figure 2 shows SA's total wind farm output prior to the Black System. The variation shown is typical of the intermittent nature of wind generation. The red dashed line depicts the time of the Black System.

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

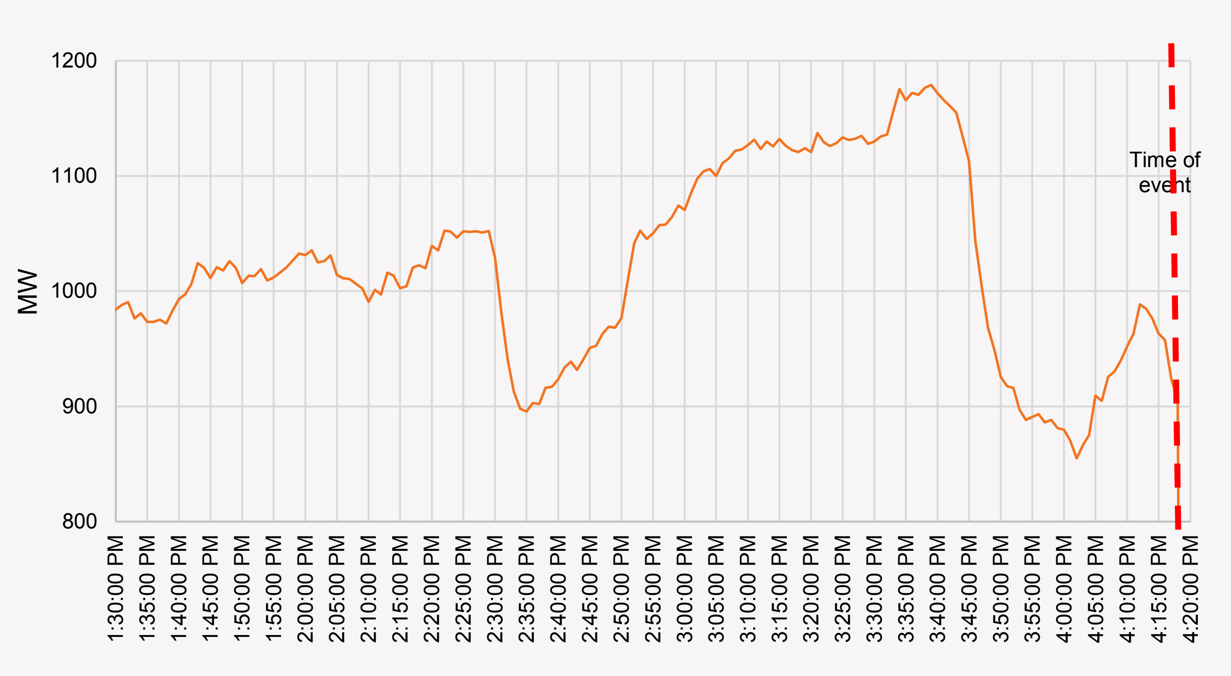


Table 3 shows SA transmission equipment which was out of service before the event or was returned to service early because of the approaching storm.

Table 3 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.

Outage	Start date/time	End date/time	Constraint set invoked	Status
Torrens Island Power Station (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 3 contains additional outage entries compared to the *Preliminary Report – Black System*.

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.[23] 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 4 were in place immediately prior to the Black System.[24]

Table 4 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)
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

Frequency control ancillary services (FCAS) enable AEMO to control the frequency of the power system and ensure the system meets the frequency standards prescribed by the Reliability Panel.

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

[24] Table 4 contains additional constraint entries, compared to those listed in the *Preliminary Report – Black System Event in South Australia on 28 September 2016*.

There are eight types of FCAS, which can be grouped into two categories: six types of contingency FCAS, and two types of regulation FCAS.[25]

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.

There was no local SA regulation FCAS[26] 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.

There was 15 MW of contingency raise FCAS response enabled on each of three Torrens Island Power Station B (TIPS B) generating units prior to the event. This response was incidentally enabled to meet a global NEM requirement, not a local requirement in SA.

Table 5 details the constraint equations that related 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).[27] This indicates the power system was in a secure operating state during the pre-event timeframe.

Table 5 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

The constraints in Table 5 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[28] 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).

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

[26] 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).

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

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

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 6.

Table 6 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]	18/12/2016 13:38	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 See Section 3.1.4 for more details.
c Occurred after the Black System, hence actual time unknown.

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.
- 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.[29] 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.[30] Other recorded maximum wind speed data[31], closer to the time of the Black System, indicates values around 100 km/h.[32] Appendix E.1 shows a summary of forecast and worst case actual data.

The report published by the BOM[33] 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[34], after this assessment had been made, indicated forecast wind speeds up to 140 km/h (gusts).[35] 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.

[29] Information provided to AEMO indicates that damaged transmission lines were subjected to actual wind speeds that were much higher than forecast. See Section 5, Impact on Power Transmission Network, page 39, BOM report, *Severe thunderstorm and tornado outbreak South Australia 28 September 2016*, available at: http://www.bom.gov.au/announcements/sevwx/sa/Severe_Thunderstorm_and_Tornado_Outbreak_28_September_2016.pdf/.

[30] Last paragraph page 21, BOM report 2016.

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

[32] See Appendix E.2 for actual wind speed data for Snowtown, Port Pirie, Port Augusta, and Clare.

[33] See Section 4 Tornado Damage Assessment, page 22, BOM report.

[34] See Appendix E.1 Forecast Weather vs Actual, Table 21.

[35] BOM report 2016.

3. EVENTS RESULTING IN BLACK SYSTEM

Where AEMO has completed investigations and reached conclusions since it published the previous report in December 2016, these points are highlighted.

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.[36]
- 330 MW of SA gas generation.
- 613 MW of electricity imports via the two interconnections with Victoria (Heywood and Murraylink).

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.[37]

Following these faults[38], and the resulting six voltage disturbances[39], there was a sustained reduction of 456 MW[40] 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.

Chapter 3 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.

[36] High speed monitoring data showed 850 MW.

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

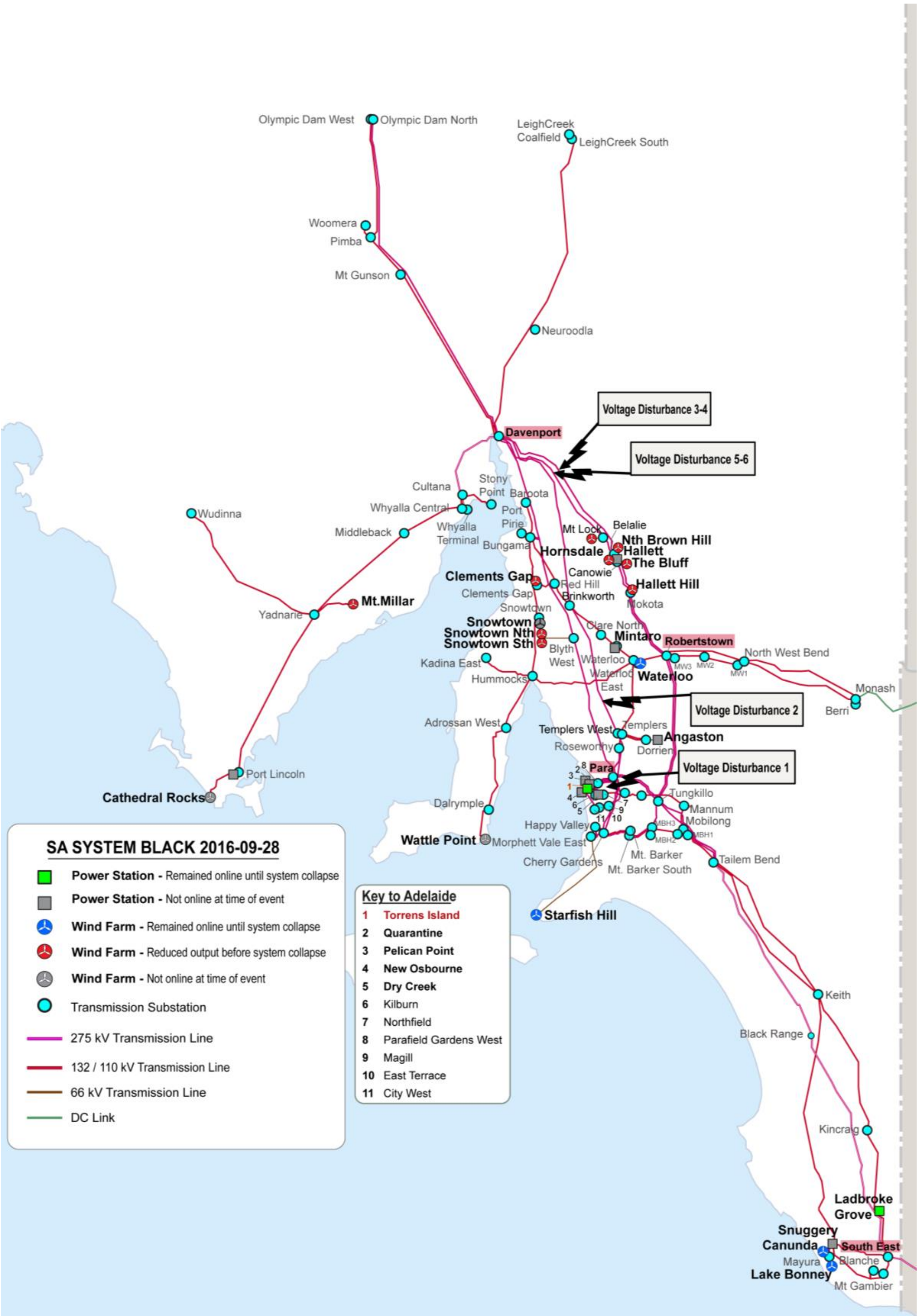
[38] In a power system, a "fault" is a condition that causes failure of the equipment in the circuit to deliver energy as intended. In this context, it is mainly the flow of current from a high voltage conductor to earth through an arc resulting from a lightning strike or direct contact caused by a fallen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

[39] 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.

[40] 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 shows the approximate location of the faults on the SA transmission network in relation to the major substations in the area.

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 Black System. Table 7 provides more detail on each transmission line fault.

Table 7 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.[41] 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.

Information obtained from ElectraNet's fault recorders, and comparison against connection point voltages for all on-line generators, indicate that all faults, including those caused by an unsuccessful auto-reclosure, were cleared within the time settings of the appropriate primary protection systems, which ranged from 80 to 120 milliseconds (ms).

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 Black System are illustrated in Appendix G (Figure 39 to Figure 42).

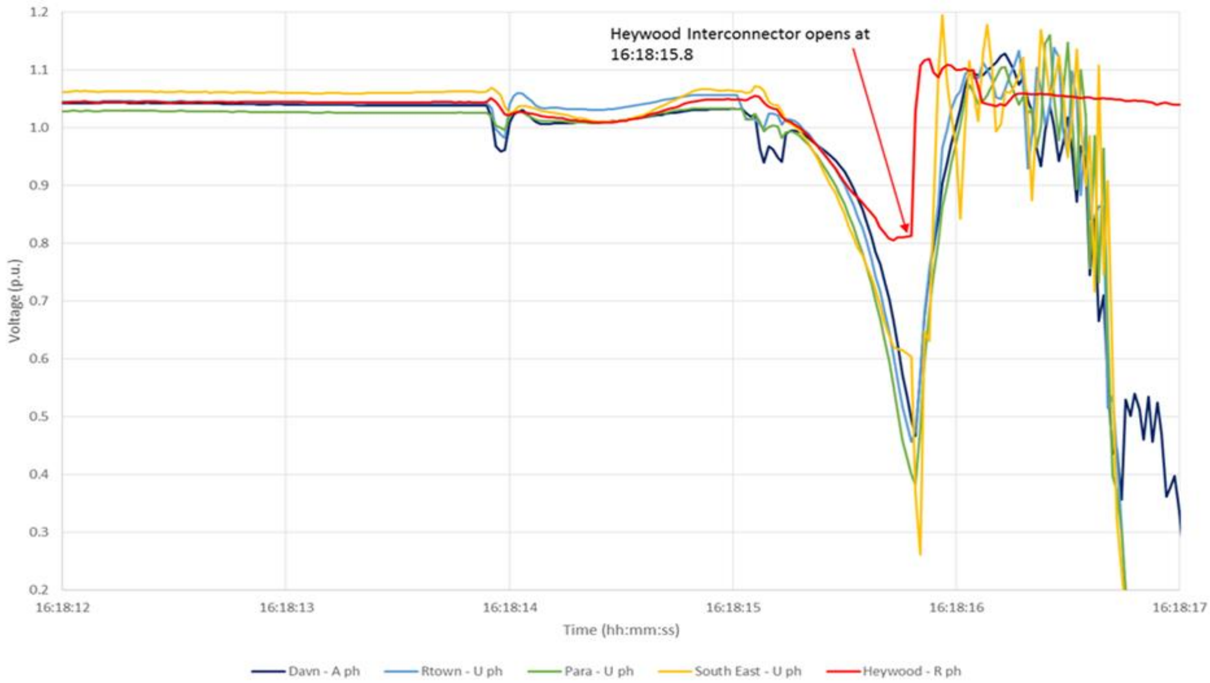
Figure 4 shows voltages measured at a number of key 275 kV points across the SA networks, as well as the 275 kV voltage measured at Heywood in Victoria, for the period immediately before loss of the Heywood Interconnector.

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.

[41] The Davenport–Mt Lock and Davenport–Belalie lines share common tower structures.

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.

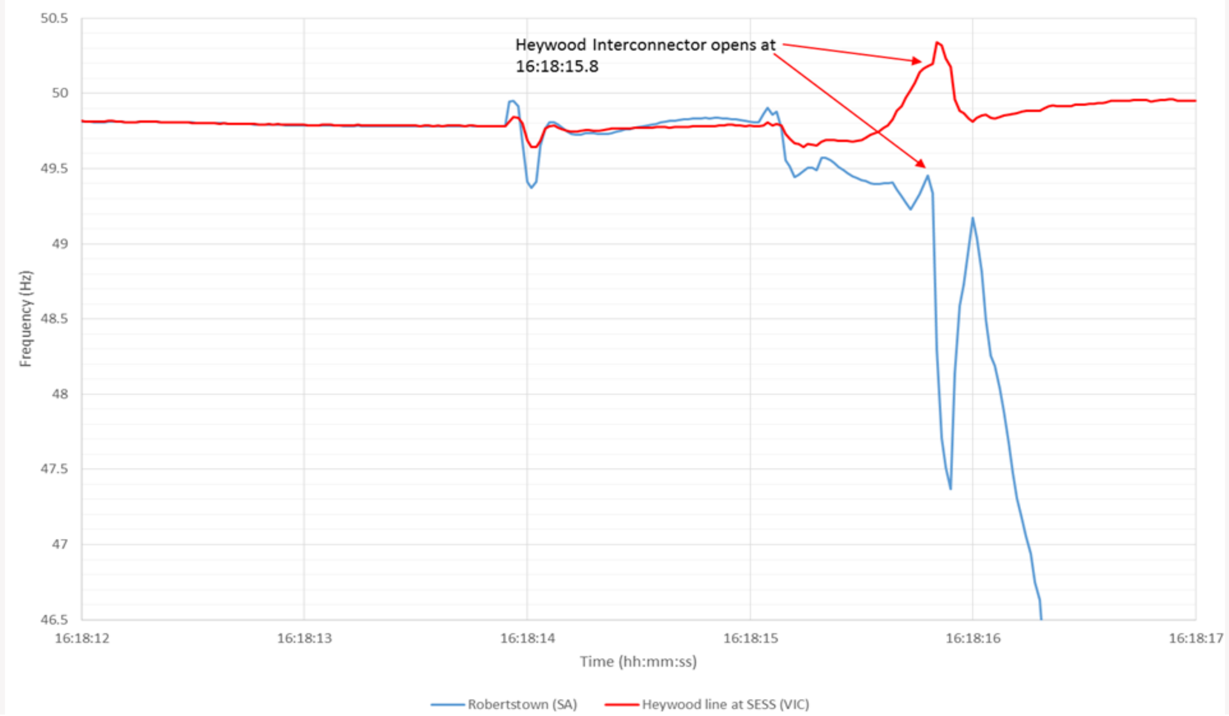
3.1.3 Measured frequencies

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.

Figure 5 shows a separation in the measured frequency between the two areas in the period immediately prior to loss of the Heywood Interconnector. This is caused by the growing angular difference between the respective voltage phase angles, which also confirms the 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.

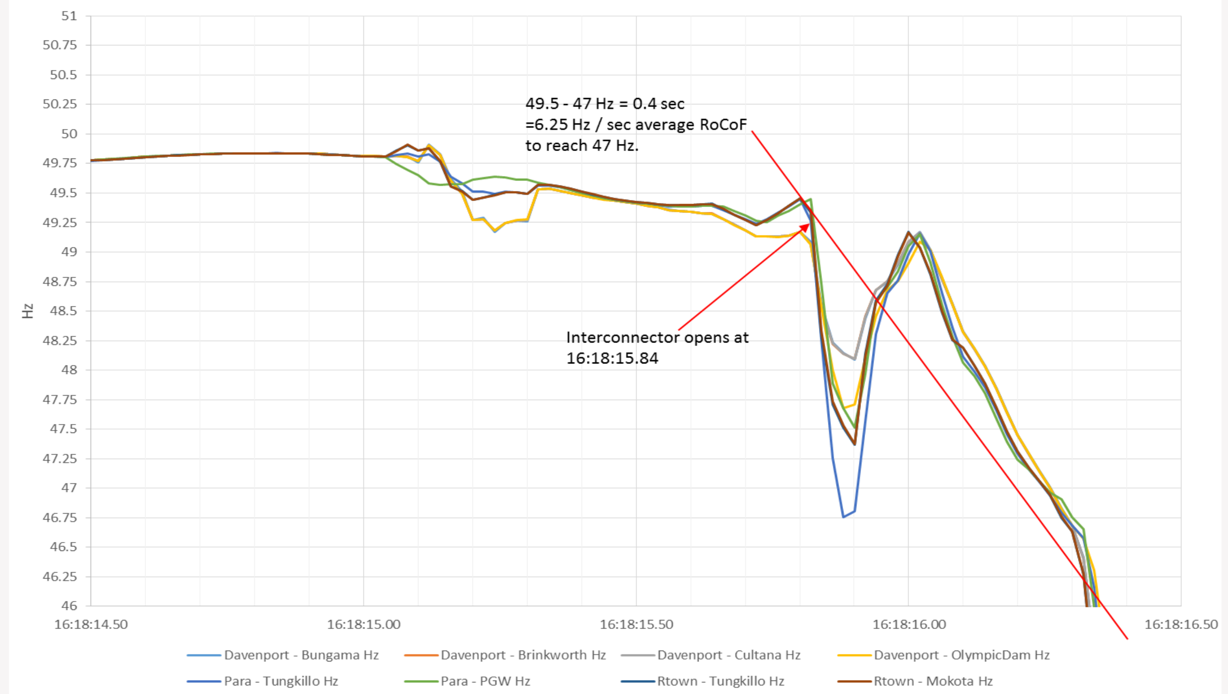
On 28 September 2016, the UFLS scheme did not trigger prior to the loss of the Heywood Interconnector, as the frequency remained above the 49 Hz trigger level.

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 when 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 possible 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 RoCoF 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 RoCoF had been low enough to allow the UFLS to operate as designed, resulting in 60% of SA load being shed before the frequency reached 47.0Hz, the remaining load of approximately 800 MW may still have been too great for the remaining generation[42] to maintain the islanded system frequency.

3.1.4 Cause of electrical faults

Lightning strikes

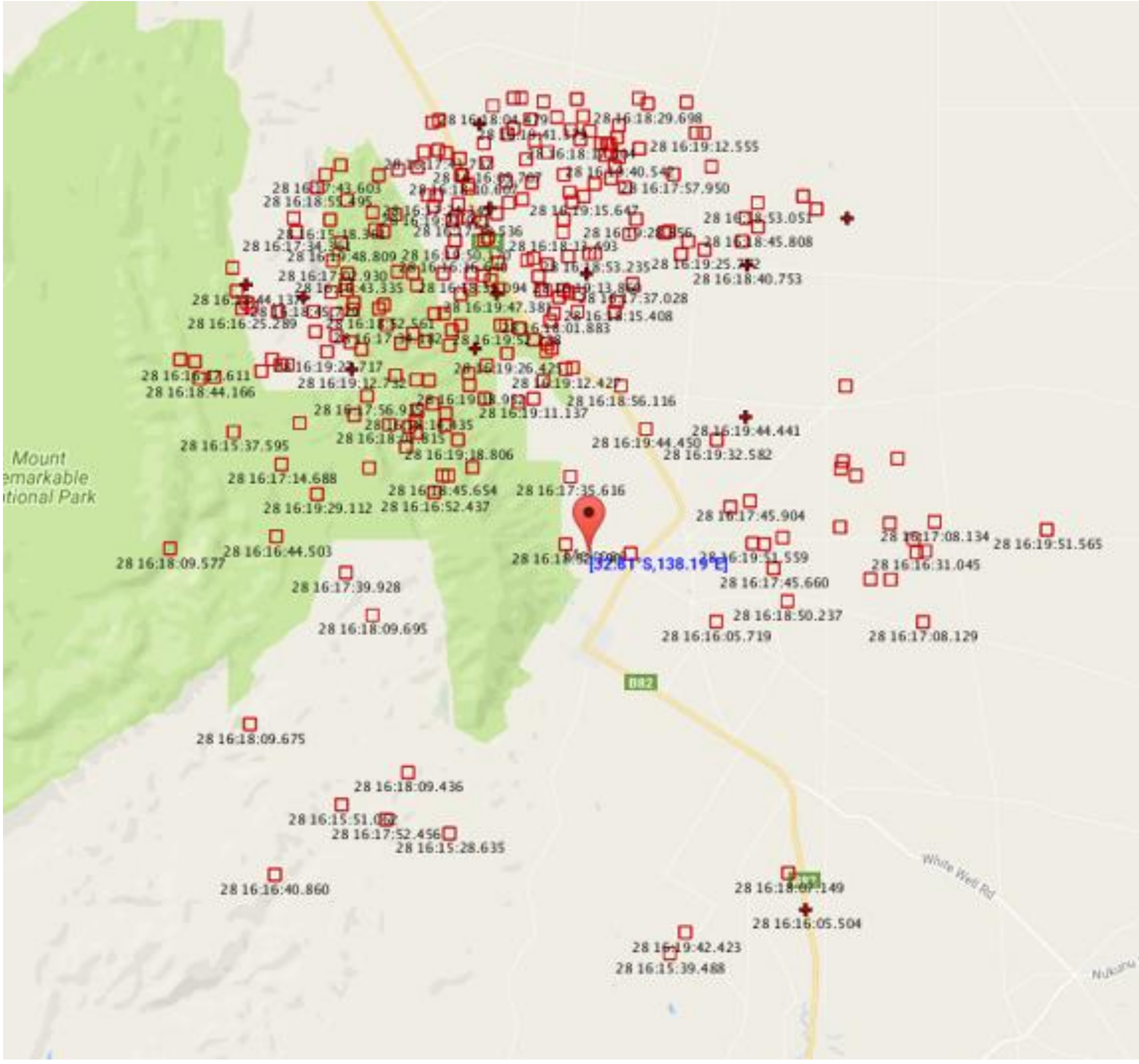
Close inspection of lightning strike data for various locations in the mid-north and northern parts of SA during the five electrical faults indicates low levels of lightning strikes for most locations except Melrose.

[42] 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 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).

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 7) 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.

The BOM post-event report[43] confirms the presence of tornadoes near the following transmission circuits between 1605 hrs and 1635 hrs on 28 September 2016:

- Brinkworth–Templers West 275 kV line.
- Davenport–Belalie 275 kV line.

[43] BOM. *Severe thunderstorm and tornado outbreak South Australia 28 September 2016*. Available at: http://www.bom.gov.au/announcements/sevwx/sa/Severe_Thunderstorm_and_Tornado_Outbreak_28_September_2016.pdf.

- 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 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 (see Appendix V).

General high wind speeds

During this period, the highest recorded wind gust was 104 km/h, which was measured at the Snowtown weather station at 1538 hrs. In its report, however, the BOM indicates wind strengths ranging from 190 to 260 km/h in localised areas and evidence of tornadoes.[44]

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

3.2 SA Generator performance

Where AEMO has completed investigations and reached conclusions since publishing its previous report in December 2016, these points are highlighted.

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.[45]

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.

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:

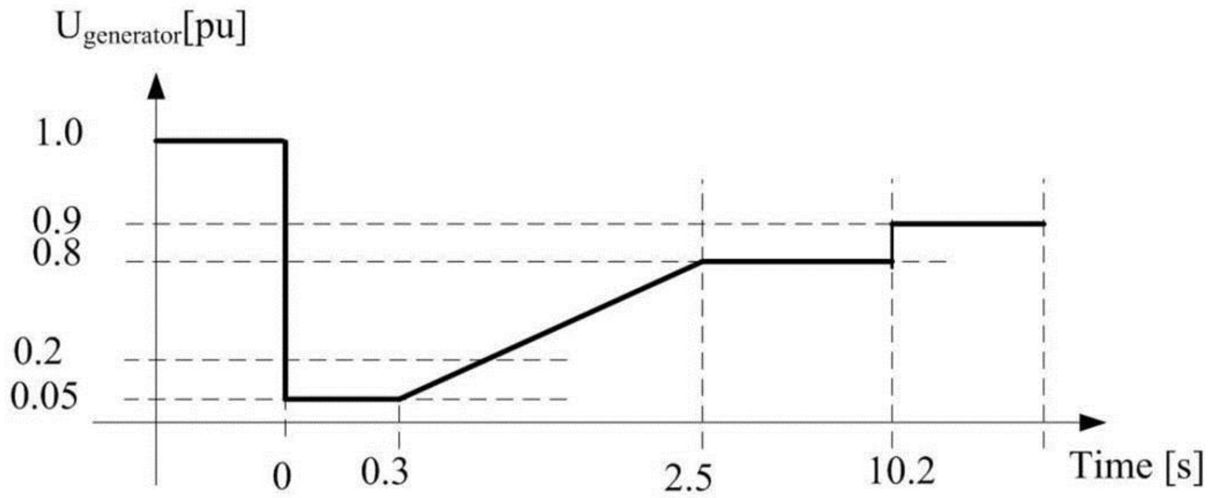
- For example, this turbine can ride through a fault with a residual voltage of 5% for 300 ms. If the fault lasts for longer than 300 ms at 5% residual voltage, the turbine will disconnect. Equally, if the fault has a residual voltage less than 5% at any time, the turbine will disconnect.

[44] Information on wind speeds updated from that in third report to reflect detailed information from BoM

[45] 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.

- Both these disconnection examples occur because the time-voltage profile of the fault is not within the turbine withstand capability, that is, not above the black line.

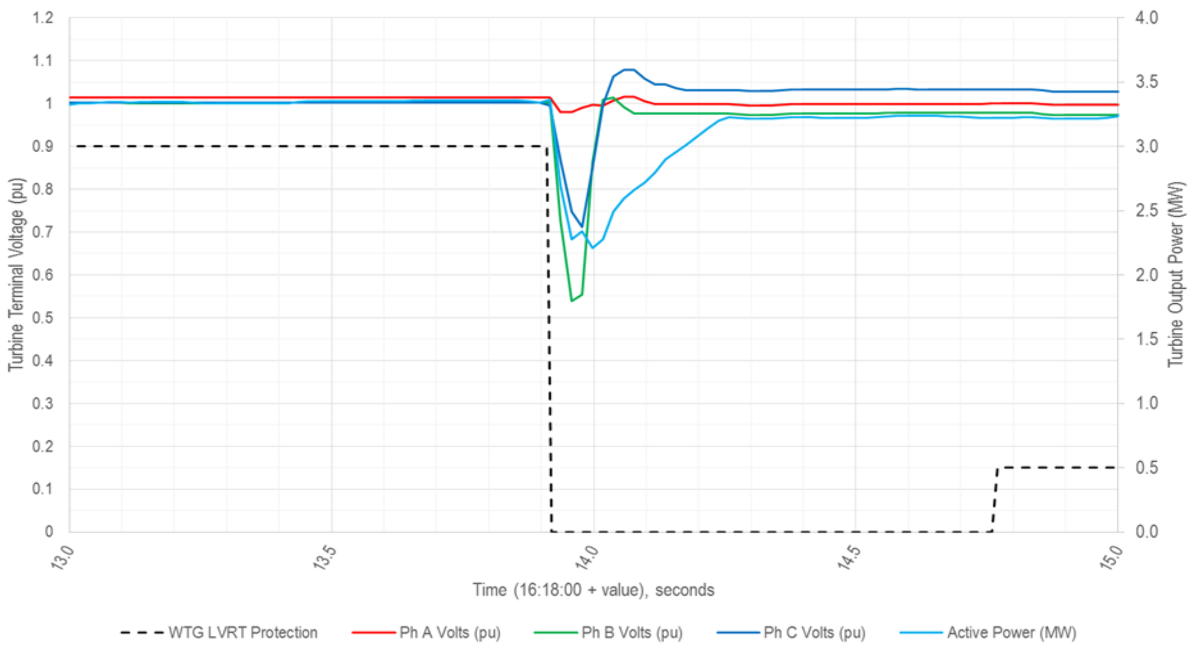
Figure 8 Example of low voltage ride-through withstand capability curve at the wind turbine terminals



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[46] 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



[46] Active power is the product of the voltage and the component of current which is in phase with the voltage.

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.[47]

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.

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[48] 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.[49] Non-compliance may be identified by Generators, AEMO, or network service providers, and can be

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

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

[49] 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 always be 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.

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, 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.
- Performance 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.[50] 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 8.

Of the 13 wind farms on-line prior to the event, four remained in service: Canunda, Lake Bonney 1, Lake Bonney 2 & 3[51], 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.

[50] AEMO can be made aware of any unexpected behaviour regarding 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).
- Notices of non-compliance, to be submitted by wind farm owners as soon as identified, under 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 being imposed on any wind farms.

[51] 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.

Table 8 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	Yet to be confirmed	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
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 8 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 leading up to the Black System. Differences between SCADA and high speed data occur because 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.

The sustained power reduction levels shown in Table 8 also account for the disconnection of a small number of wind turbines due to the high wind speed and other turbine protection mechanisms (approximately 40 MW between the last five voltage disturbances).

Cause of wind generation reduction

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

To illustrate the output reductions, the wind farms have been grouped together as shown in Table 9.

Table 9 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 2 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 about each group.

Groups 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 Groups A and B in this report.

Groups 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 one wind farm in Group C exhibited sustained power reduction during the six voltage disturbances on the transmission system.

The operating philosophy of Group C wind turbines differs from all other wind turbines. 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 (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 megawatts per second (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 by nine wind farms during the six successive voltage disturbances, a further reduction of 42 MW of wind power 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 (Group D) that activated their fault ride-through mode.

While Group D 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.

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

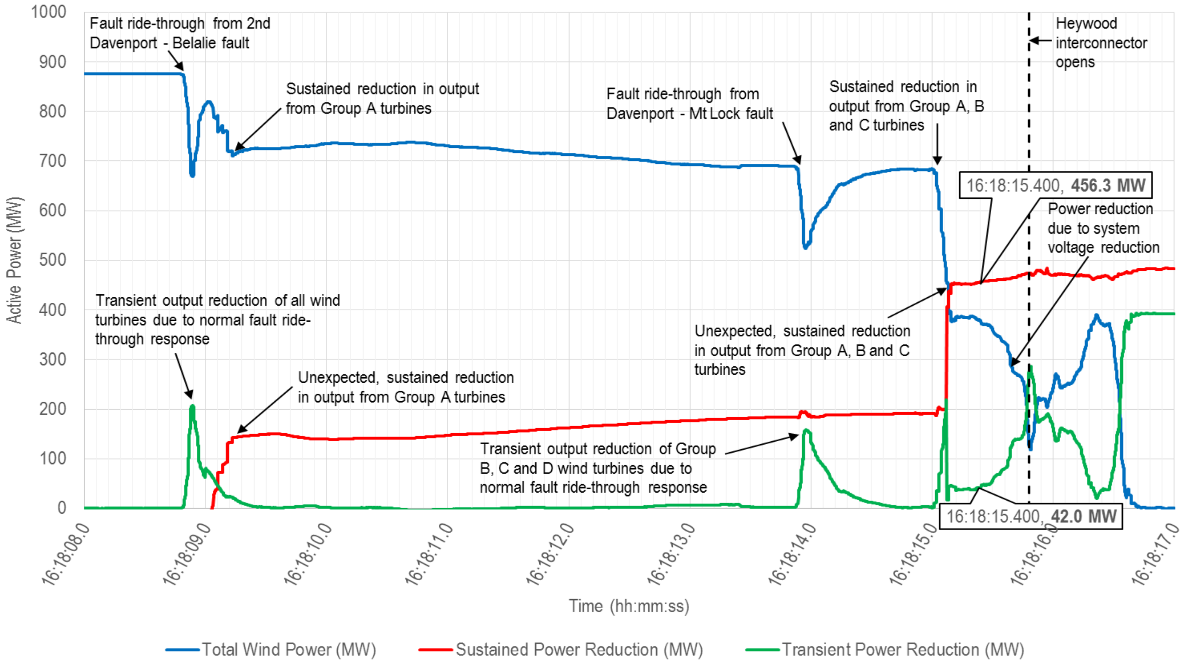
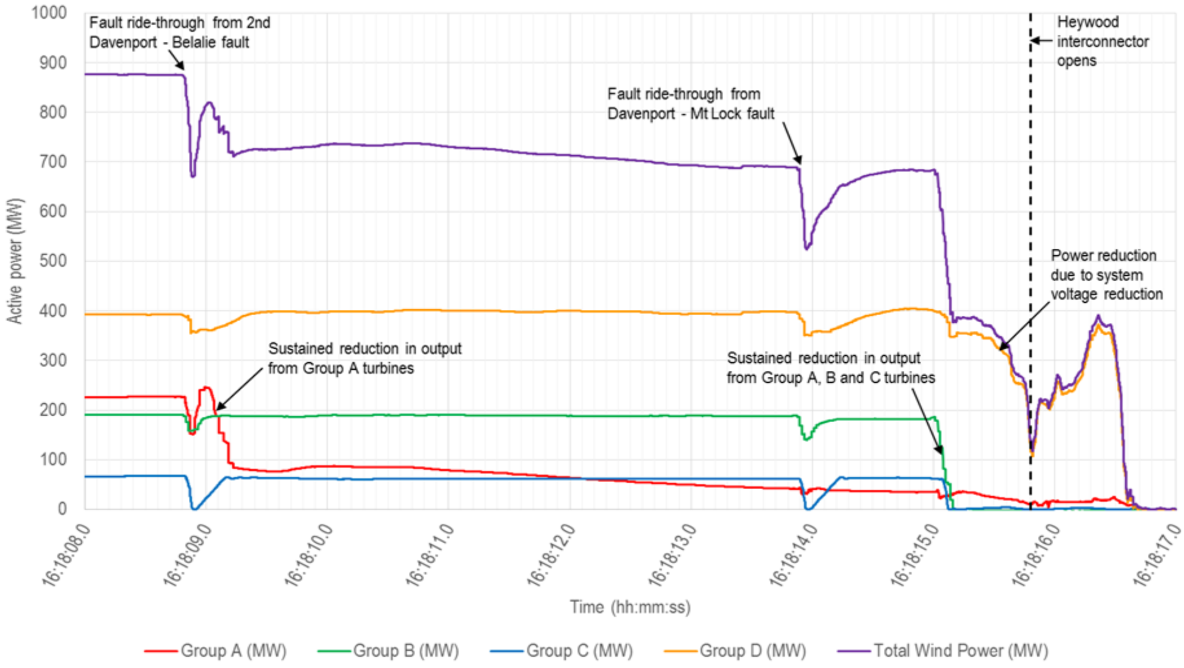


Figure 11 illustrates the power reduction of wind farms, based on the grouping in Table 9. It also highlights the following observations (noting the SA power system had experienced three voltage disturbances just prior to the time shown on Figure 11):

- **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 some of the remaining Group A wind turbines from a total of 80 MW to 40 MW just prior to the rapid voltage decline. The relevant Generator has confirmed that 23.1 MW of this power reduction was caused by the disconnection of wind turbines due to high wind speed and other turbine protection mechanisms during the last five voltage disturbances.
- **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 43 to Figure 55 in Appendix I.1 show the response of individual wind farms during the Black System. These figures illustrate connection point voltages, active power, 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.
- Each fault seen by individual wind turbines was 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 during or immediately after the clearance of the voltage disturbances.
- 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.

While both the sustained power reduction and the reduction in reactive current injection were unexpected responses, AEMO notes that the existing generator performance standards under the NER do not include specific minimum requirements that would have prevented or mitigated those responses. This is discussed further in Appendix X.4.1 and X.4.2.

- Of the 14 on-line wind farms, 10 utilise dynamic reactive power support plant in the form of static compensators (STATCOMs).

  AEMO investigated the response of these devices in detail (see Appendix X.4.2), and has concluded that unexpected measured responses were attributed to the reverse polarity of current measurement devices at one of the wind farms. This has since been rectified by the relevant Generator.

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 excessive wind 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. Of the 456 MW sustained power reduction by nine wind farms, approximately 35 MW of wind generation was disconnected due to excessive wind speed during the last five voltage disturbances.

This was not a material contributor to the event, as shown in Appendix M.2, which discusses a scenario where wind farms did not reduce output power due to the multiple voltage disturbances, but assumes a loss of 200 MW of wind generation due to high wind speeds immediately afterwards. Simulation studies carried out by AEMO demonstrate that the SA power system would have remained stable and interconnected under these conditions.

Subsequent measures taken by Generators in SA

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 both:

- Avoid excessive stress and fatigue on turbine mechanical drive train, tower, and so on.
- 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 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.

AEMO permitted the impacted Generators to implement the proposed new settings on-site, enabling successful ride-through for a larger number of successive faults. These Generators subsequently amended these protection settings.

One Generator confirmed that its turbines have a similar protection function, but it was not operating at the time of the incident. This Generator has also amended its settings for this function.

Table 10 indicates the current capability of SA wind turbines in relation to successive fault ride-through capability, remedial measures applied 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.

Table 10 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 A1	351	No	2 within 2 minutes[a]	6 within 2 minutes
Group A2	155	No	2 within 2 minutes	15–19 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 (also 10 within 2 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.[52]	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, following modifications applied on Group A wind farms, they can all successfully ride through at least six voltage disturbances within 120 seconds, allowing them to remain connected for the sequence events occurred prior to the Black System.

In addition to the impacted wind farms in SA, AEMO is 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.
- Changes to protection settings of Group A and B wind farms have already been implemented.
- The impact of increased pre-set protection limits for Group A wind farms has already proven to have a positive impact in improving SA’s system resilience to network fault events and non-credible generation disconnection. Specifically, on 3 March 2017, the SA power system was subject to three solid faults in a period of two seconds, each resulting in the 275 kV terminal voltage at the TIPS B units dropping below 0.2 pu. All on-line Group A wind farms rode through these three faults within two seconds. It is likely that the settings applicable on 28 September 2016 would have resulted in disconnection of some or all turbines at these wind farms on 3 March 2017.
- Possible residual risks in this area still remain.

[52] Two operators have not yet responded to AEMO’s request, and another has advised that they are unable to provide the information.

AEMO has completed investigations and identified the following residual risks in terms of wind farms' inability to maintain output following a series of faults in quick succession. These are discussed further in Appendix X.2:

- The capability of Lake Bonney 1, Starfish Hill, and Wattle Point Wind Farms to maintain output following a series of faults remains unclear.
- The remaining Group D wind farms can withstand 10 faults within 30 minutes, compared to a maximum of 11 historical faults recorded in ElectraNet's network (excluding distribution system faults and faults on the Victorian transmission network).[53]
- The situation would be exacerbated if any of these faults also resulted in:
  - Disconnection of other large wind farms such as Snowtown 2 Wind Farm.
  - Activation of zero power mode of operation for Mt Millar Wind Farm.

  It is noted that the occurrence of 11 successive faults within 30 minutes is unlikely to result in activation of fault ride-through mode every time. Fault ride-through mode is activated when the wind turbine terminal voltage drops below a certain threshold. The diverse geographical location of these wind farms means that each fault is unlikely to activate fault ride-through mode for all on-line wind farms in this group.

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 the 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.
- The three TIPS B generating units were each enabled to provide 15 MW of 6-second contingency FCAS prior to the event. However, the frequency in SA prior to separation was only just below the level where FCAS delivery is required to begin, until after the loss of the Heywood Interconnector at 16:18:15.8
- The rapid decline in system frequency following loss of the Heywood Interconnector did not allow time for more substantial governor response from these units, as it can take up to six seconds for

[53] It should be noted, as experienced on 28 September 2016, that due to the lower levels of system strength, the effect of a fault on the SA power system can be now more widely felt. On 28 September 2016, one fault north of Adelaide triggered the LVRT mode for wind turbines located near Mt Gambier.

these generating units to increase their active power output when they participate in the contingency FCAS market.

- 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 simply to trip the generator. When this trip mechanism is activated 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 SESS 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 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 set to trip instantaneously at 13.2 kV. After 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.[54]

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.

Figure 12 SA system frequencies relative to the Heywood Interconnector

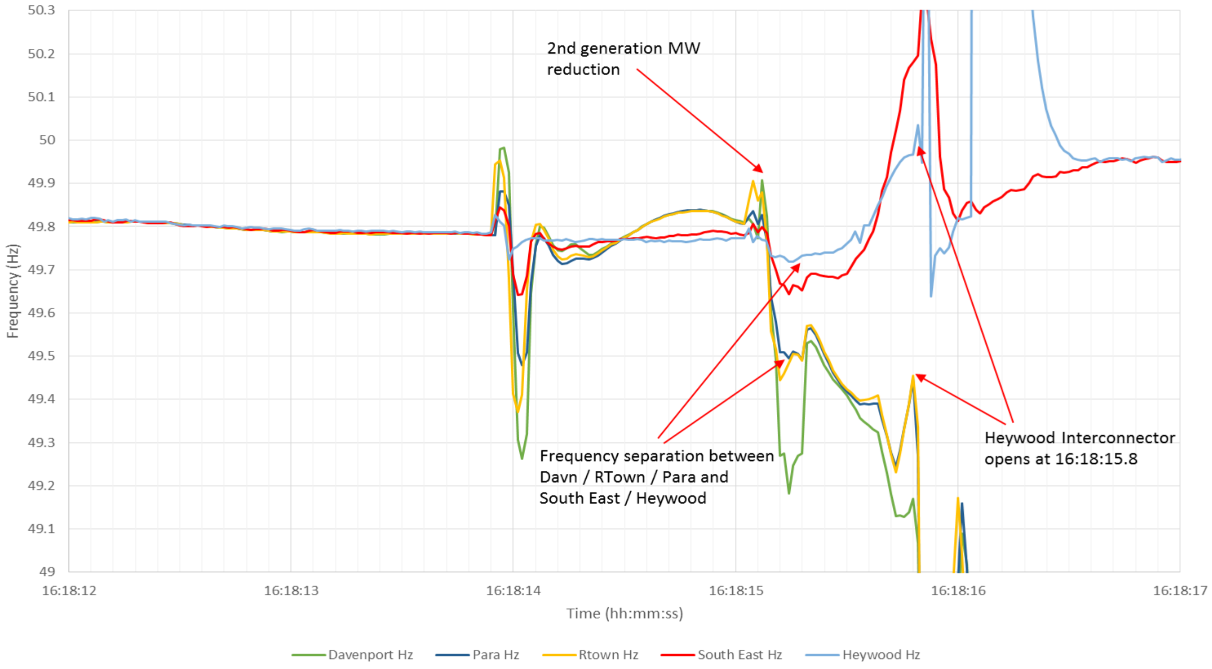
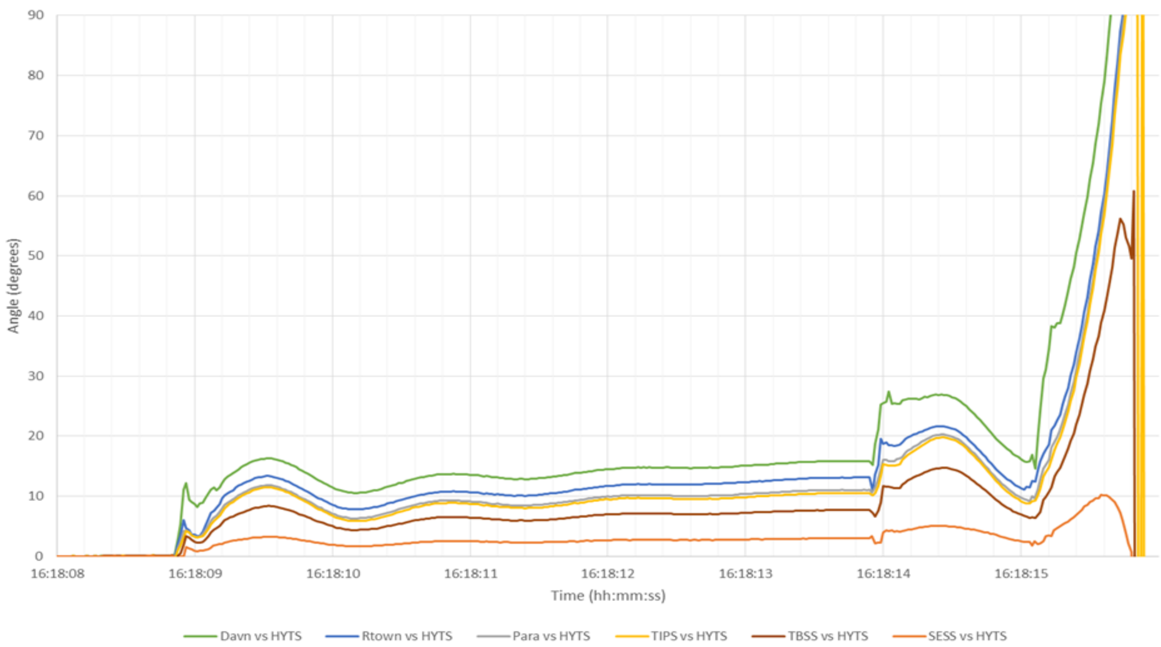


Figure 13 Voltage angle difference between various SA nodes and Heywood Substation



54 Figure 12 and Figure 13 collectively demonstrate that the natural point of separation between SA and remainder of the NEM is between South East (SESS) 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.

Cause of global voltage instability

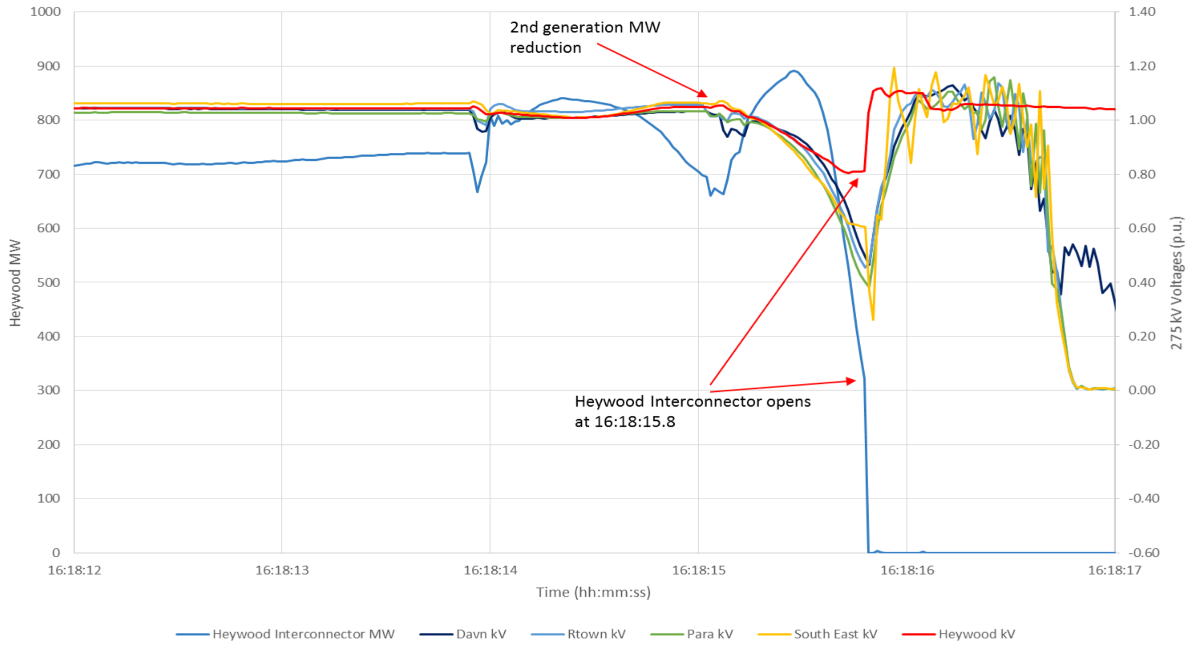
An angular difference of 90 degrees is generally used to determine the onset of transient instability and loss of synchronism between two power systems. This coincides with a point in the voltage-power curve, whereby any attempt to transfer more power across the network results in a reduction in system voltages and voltage instability is inevitable. This coincidence can be described using the '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 (LOS) protection is discussed in Appendix J.2.

The Heywood Interconnector employs duplicate LOS 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 mega volt amps (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 LOS relay, rather than the sheer size of current (over-load).

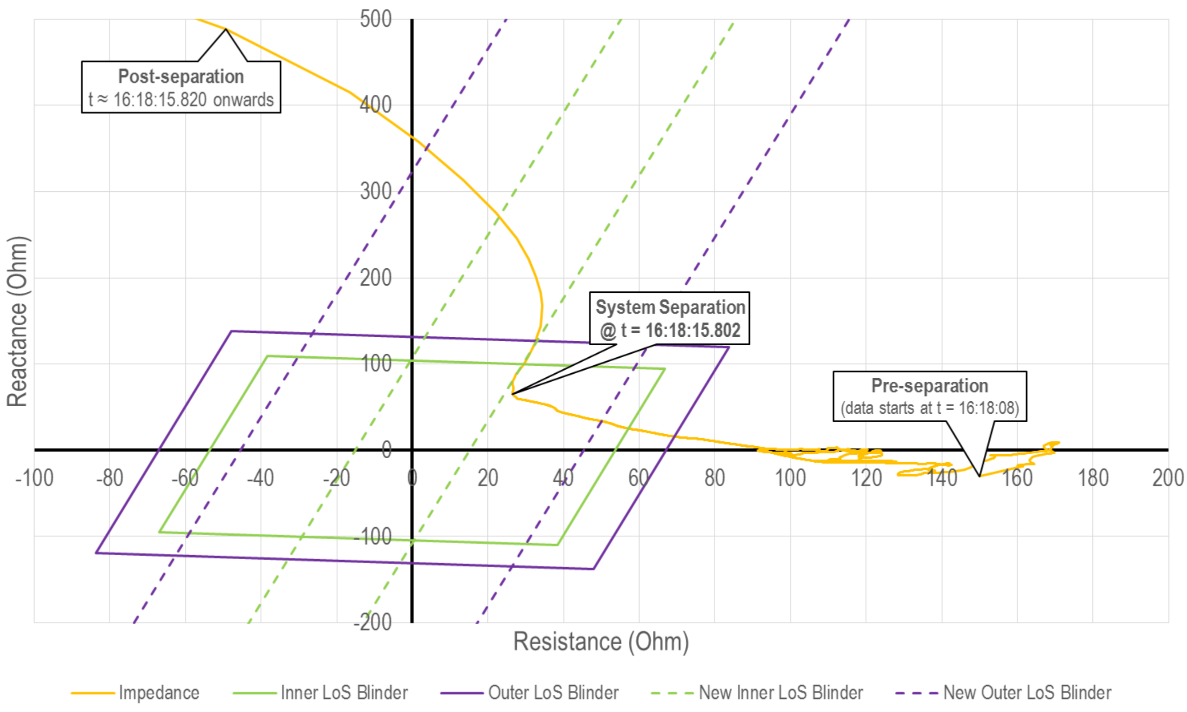
Figure 15 depicts impedance trajectory against the relay operating characteristic. This figure clearly shows that the impedance trajectory crossed both inner and outer relay blinders, resulting in correct operation of the relay and opening of the associated CB. Immediately following system separation,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

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

It should be noted that the settings of the LOS relay have changed as part of Heywood Interconnector series capacitor augmentation that changes the effective line impedance, creating the need for revised settings for a relay that acts on the system impedance. These revised settings have been in place since October 2016, and were used in the scenario analysis discussed in Appendices X and Y in this report.

Figure 15 highlights that system separation would have occurred irrespective of whether the new or the old LOS relay settings had been in place on 28 September 2016.

Figure 15 Response of Heywood Interconnector loss of synchronism relay



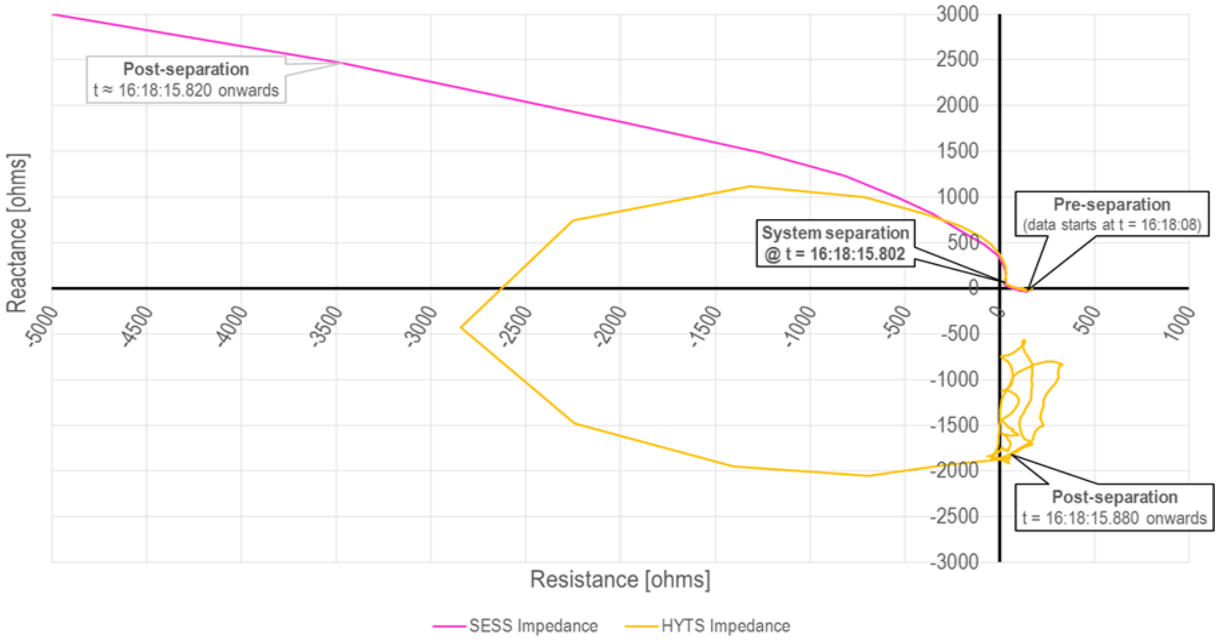
Impact on Victorian network

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 six[55] times in the seventeen years since 1999.[56]

Table 11 indicates that, in addition to the 28 September 2016 event, three other relevant system separation events[57] 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 has investigated this further to determine the extent to which these over voltages might undermine the ability to form a viable SA island. Simulation case studies conducted are reported in Appendix Y.

[55] This figure has been updated since the third preliminary report, due to the system separation event in 1 December 2016.
[56] AEMO has reliable data and records back to 1999.
[57] 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 11 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	System inertia (MW.s)	Peak Heywood flow (MW)	Time between start of frequency decline and system separation
2 December 1999	13:11	Trip of both units at Northern Power Station (520 MW)	1,130 MW	26 minutes	Yes	10,693	950	2.8 seconds
8 March 2004	11:28	Runback of both units at Northern Power Station (480 MW)	650 MW	43 minutes	Yes	7,617	825	1.7 seconds
14 March 2005	06:39	Runback of both units at Northern Power Station (465 MW)	580 MW	22 minutes	Yes	11,127	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	3,000	890	0.6 seconds

Adequacy of transfer limits for Heywood Interconnector

Works to upgrade the capacity of the Heywood Interconnector from 460 MW to a nominal capacity of 650 MW were completed early in 2016. This involved installation of a third 500/275 kV transformer at Heywood Terminal Station in Victoria, installation of 50% series compensation on the Tailem Bend–South East 275 kV lines in SA, and reconfiguration of the 132 kV transmission lines running in parallel with the Tailem Bend–South East 275 kV lines.

Following completion of these works, a program to progressively test the operation of the Heywood interconnection at higher power transfers commenced. On 28 September 2016, the maximum transfer allowed on the Heywood Interconnector from Victoria to SA under this testing program was 600 MW. Work to test it at a transfer limit of 650 MW from Victoria to SA had not yet commenced.

ElectraNet had previously provided AEMO with transfer limit equations for flow on the Heywood Interconnector from Victoria to SA, considering its operation up to a maximum limit of 650 MW. This advice included limit equations for both voltage and transient stability, considering loss of the largest generating unit in SA, and loss of key transmission elements in SA. These transfer limits vary with system conditions, and at times set a limit above 650 MW from Victoria to SA, however, a separate maximum cap of 650 MW on transfers was still to be used at all time.

AEMO undertook due diligence on this advice, which indicated these limit equations were appropriate to maintain power system security in SA. Both ElectraNet's work to develop these limit equations, and AEMO's subsequent review of this advice, were undertaken with the same power system dynamic model, available via AEMO's OPDMS system.

Following the Black System, a decision was made to leave the maximum transfer limit at Heywood at 600 MW, pending the findings of the investigation.

AEMO's investigations included dynamic simulations of the Black System to compare simulation results from the available power system dynamic model with the reality observed during the event.

This work identified a range of differences between simulations and reality, some small, some important. Among these were differences in the active power recovery time of some power electronic interfaced generation, and in the depth of active power reduction immediately following faults. The performance standards for several existing wind farms in SA do not have any specific requirements with regard to the active power response during and after faults.

Investigation into these differences has allowed corrections to be applied to the simulation models to give a more accurate simulation of the Black System. In many cases, the differences individually are small, but the aggregate effect of these makes an important difference to the overall performance of the SA power system in response to disturbances, particularly to flows observed on the Heywood Interconnector.

These simulation models were then used to perform a range of 'what-if' scenarios, including assessment of transfer limits on the Heywood Interconnector at high power transfer levels. This simulation work has identified some dispatch scenarios that would have been permitted, based on a maximum scheduled transfer level of 650 MW or 600 MW, and that may have led to the insecure operation of the SA power system.[58]

In the short term, AEMO plans to modify existing transfer limits to account for these findings, so as to maintain the secure operation of the SA power system. The existing transfer limit equations include a term for the maximum sustained loss of generation from the SA power system. Initially, AEMO will apply a varying increase to this maximum generation loss term based on real-time power system conditions, to account for the observed active power response of generation in SA to disturbances. Under conditions of low wind generation, this will result in the same transfer limits as previously advised by ElectraNet, however, under high wind conditions it will reduce the allowable transfer limits on the Heywood Interconnector.

In the longer term, AEMO will work with ElectraNet to review the transfer limits applied to the Heywood Interconnector more broadly, to fully incorporate the findings of this investigation, and allow for the

[58] See details of studies in Appendix X.1.

highest utilisation of the Heywood Interconnector that is consistent with maintaining power system security.

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.

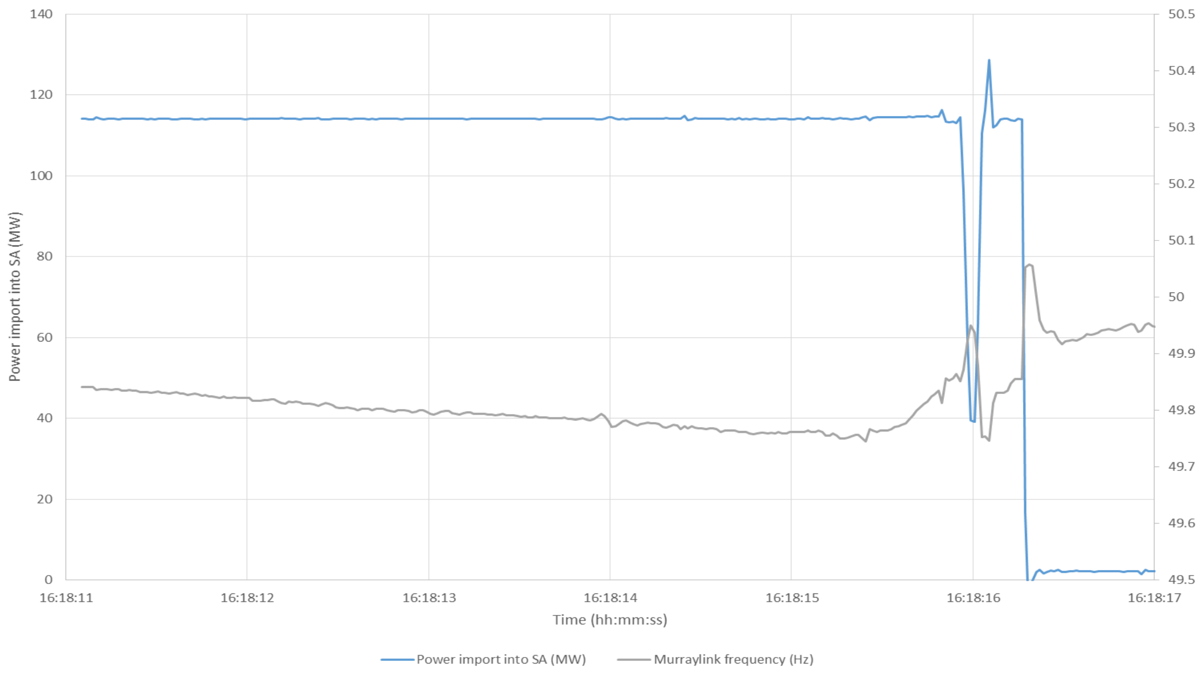
- The Murraylink design has a fast response time to voltage disturbances of less than 20 ms.
- Occurrence of a voltage disturbance causes a temporary increase of up to 150% in the HVDC link current. After around 20 ms, the nominal HVDC link current is restored.
- This means power flow across Murraylink recovers much faster from a voltage disturbance when compared to other technologies.
- The negligible decline in active power transfer across 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:

- 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 (see Figure 17). 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

The SA transmission network includes two 80 MVAr Static Var compensators (SVCs)[59] 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, shown in Figure 69 and Figure 70 in Appendix L.1, 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 oscillatory but stable due to the high SVC gain.
- Both SVCs reduced their reactive power injection in response to declining system voltages that began at 16:18:15.2.[60] It is noted that the decline in voltage started immediately after the clearance of the sixth fault and sustained power reduction by Group B and C wind turbines 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.

In summary, the operation of the SVCs was not as expected, but did not contribute to the causation chain leading to the Black System.

AEMO, in consultation with ElectraNet, has further investigated the response of the SVCs based on power system simulation studies. This review has determined that changes in their settings would not have provided any tangible contribution to avoidance of the Black System (see Appendix L.3 for more information).

The following modifications were investigated in the settings of the four SVCs:

- Faster switching of the 2x100 MVAr external capacitors at Para Substation, and the 1x100 MVAr capacitor at South East Substation.
- An increase in the slope (droop) of the SVC voltage control loop.
- A reduction in the SVC integral gain.

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 71 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.

[59] 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.

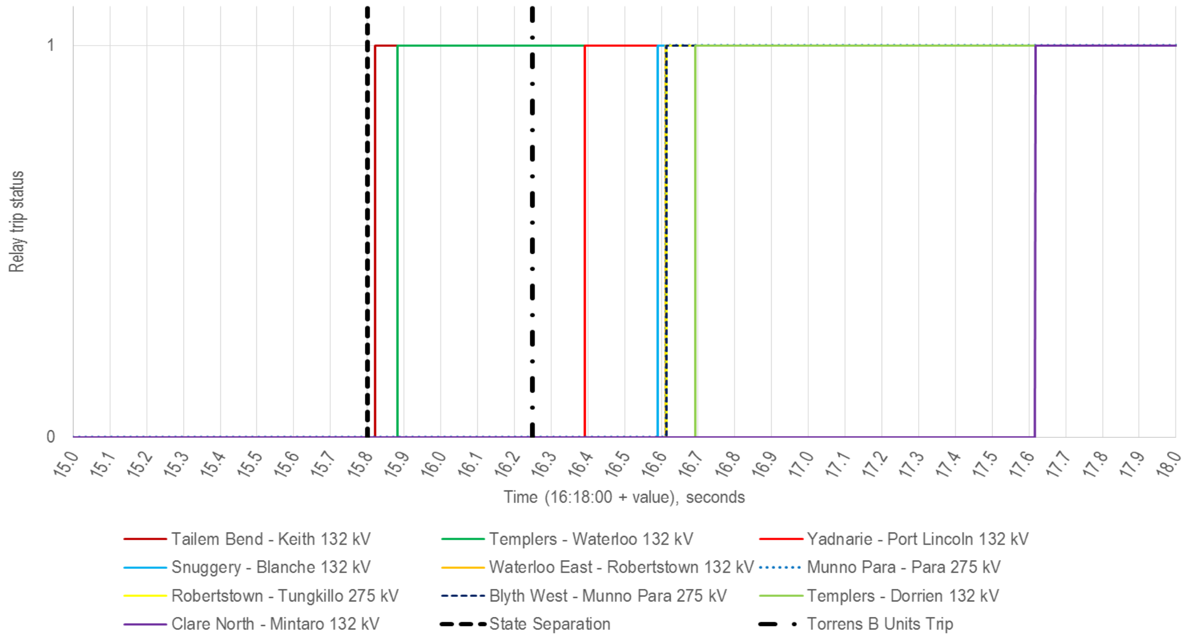
[60] Note that the under voltage protection would block these SVCs as soon as the voltage dropped to 0.65 pu for 40 ms and unblock it when the voltage returned to 0.7 pu.

3.3.3 Control and protection schemes

Impedance-based relays

Figure 18 indicates that a number of impedance-based distance relays[61] 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.

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



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.

AEMO has examined the operation of three-phase distance relays for unbalanced disturbances. More detail is in Appendix Y.7, but in summary, AEMO's investigations have identified two causes for spurious relay operations during the Black System:

- Lack of power swing blocking functions. The investigation has suggested a need for AEMO, in consultation with TNSPs and Generators, to develop:
  - Requirements for expected performance of power swing blocking for transmission networks and out of step protection for generators.
  - A strategy for location of power swing blocking and out of step tripping functions.
- Tripping due to extreme under frequency and under voltage conditions. ElectraNet is working with relay vendors to improve performance in this area.

The operation of three-phase distance relays for unbalanced disturbances will be investigated further to ensure this will not create material risks in other circumstances.

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

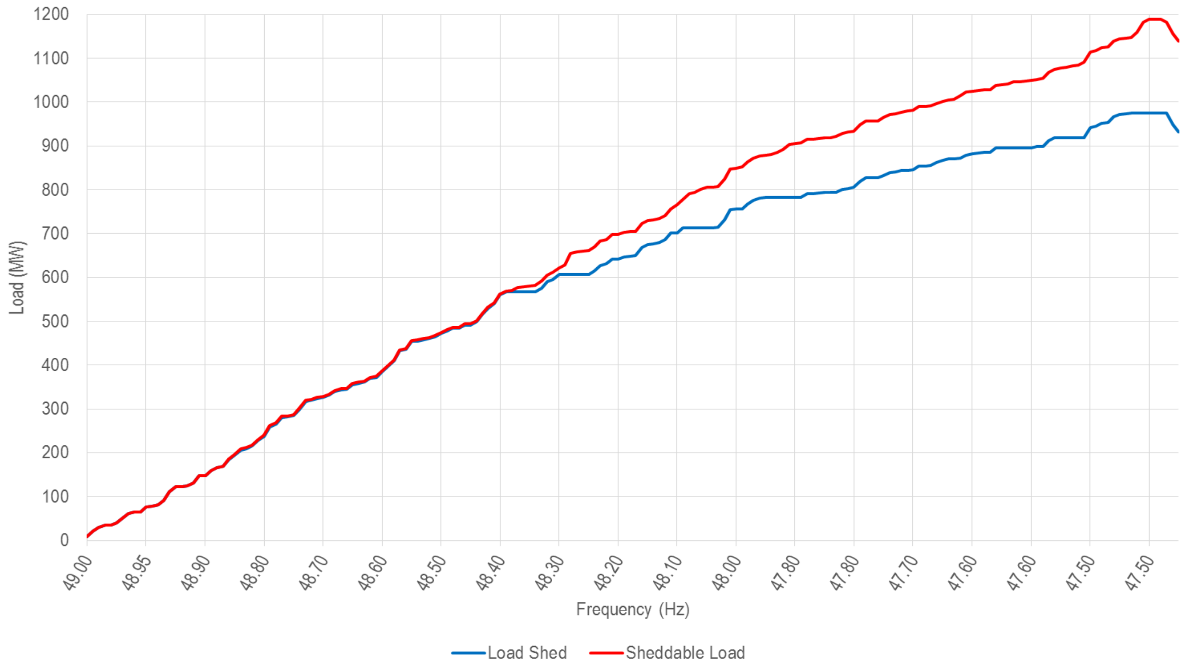
Under frequency load shedding

SA Power Networks (SAPN) records show that approximately 1,150 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 UFLS 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.

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

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



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.

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

AEMO has completed investigations into the UFLS scheme and distribution of load blocks (see Appendix Y.5.2 for more detail), and concluded that:

- 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.
  - With RoCoF values above 4 Hz/s, the likelihood of maintaining frequency is very low.

AEMO has not further investigated the effect of a distribution of load blocks different to that currently in place. This is because the simulation studies conducted by AEMO showed that a more aggressive, faster acting SPS to rebalance supply and demand following islanding would not successfully stabilise the SA power system following system separation. This means that under the conditions on the day, less aggressive measures such as shedding more load at higher frequencies by the UFLS would have been ineffective.

AEMO concluded that the benefit of an improved UFLS scheme would be very marginal, considering the physical limitations of the network in terms of availability and capability of necessary CBs and relays, and limited availability of higher percentages of operational demand for the UFLS scheme at a given time.

To maintain system stability under high RoCoF conditions, there is a need for an SPS which, in response to sudden excessive flows on the Heywood Interconnector, would initiate load shedding with a response time fast enough to prevent separation, or at least to create a stable island.

AEMO has investigated this possibility and found that:

- An SPS to prevent separation could be effective provided that:
  - A total response time in the order of several power frequency cycles could be achieved (as an example a total response time of 100 ms was studied in the report).
  - Other necessary control and protection mechanisms could operate in a consistent timeframe to ensure secure operation of the SPS (to avoid unnecessary load shedding).
- Even with very rapid shedding of load by an SPS following separation, a viable island cannot be formed under medium and low demand conditions, when there is a large imbalance between supply and demand. This imbalance would exist when the loss of multiple generating units led to separation. The key threat to the stability of an islanded SA system would be temporary over voltages, beyond the over voltage protection settings of the several generating systems. This is because load shedding as required in conditions similar to this event would require a sudden reduction in demand to levels at or lower than minimum regional demand under normal conditions. As discussed in Section 3.5.2, system strength within the island could also be an issue.

More information is in Appendices Y.4 and Y.5.

3.4 Demand response

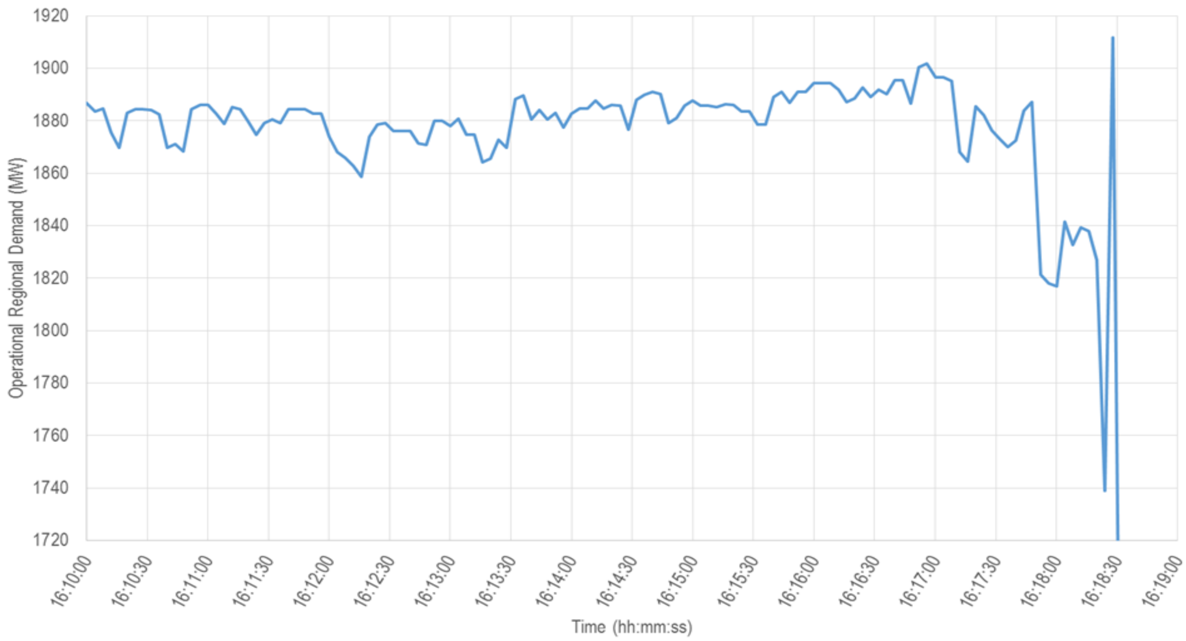
3.4.1 Overall demand response

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 on 28 September 2016



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

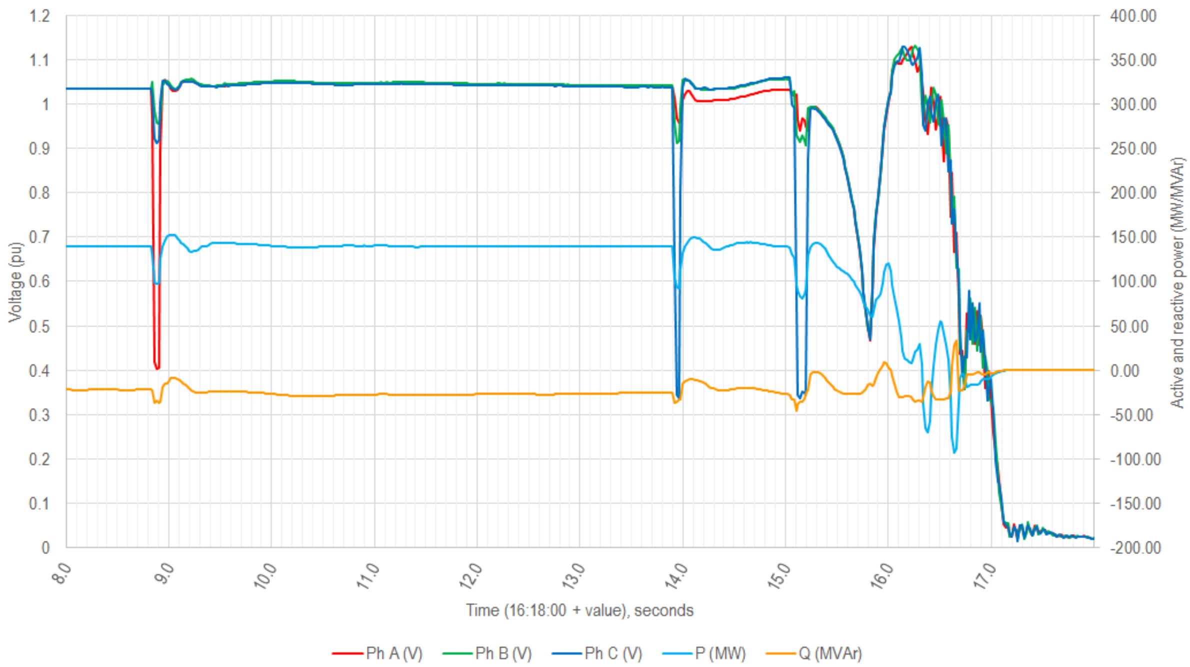
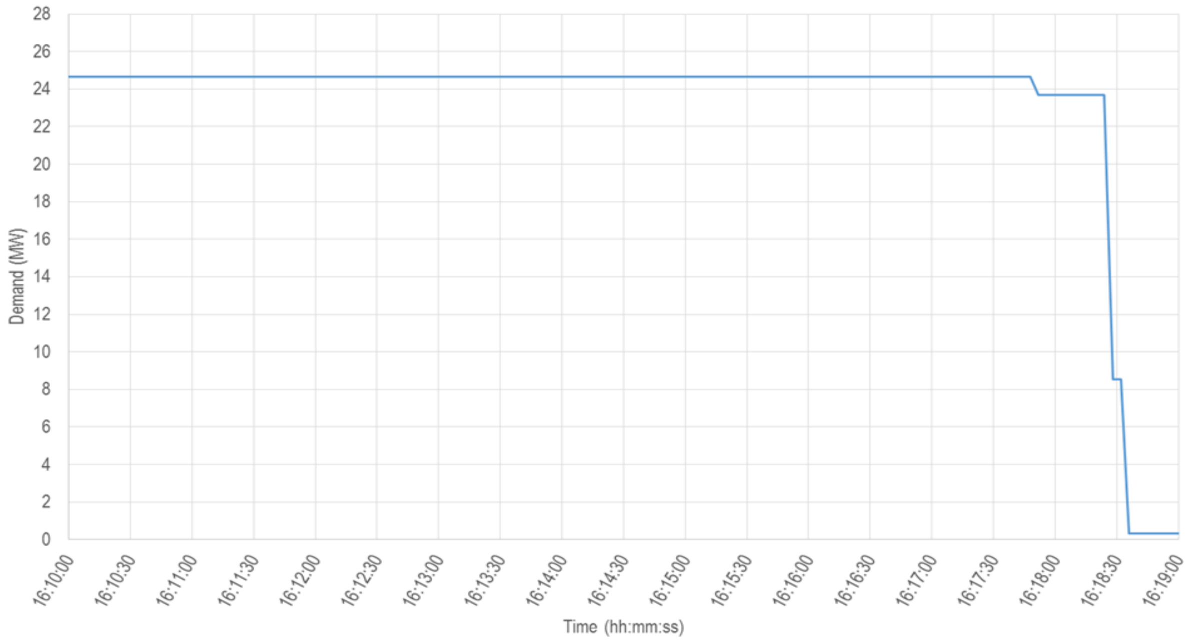


Figure 22 Port Pirie's demand variations



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, AEMO carried out steady-state analyses with the following three lines disconnected:

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

Figure 78 in Appendix M.1.1 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 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 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).[62] Figure 79 in Appendix M.1.1 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.

[62] The Port Lincoln–Yadnarie line was also damaged some time after the Black System. This was not added to the scenario, because the timing was uncertain and the loss of the line, while critical for local supply, would not have had a significant impact on the overall stability of the SA power system.

Static modelling is an indicator of a possible scenario in a point in time. Based on AEMO's static modelling, it is probable that the SA power system could have withstood the loss of all three transmission lines, and the fourth damaged after the Black System.

AEMO 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.

To corroborate the findings of static analyses discussed above, AEMO has conducted two further dynamic scenario analysis, discussed in Appendices M.1.2 and M.2, including:

- Loss of the three and four transmission lines and assuming no sustained power reduction associated with nine wind farms that occurred during the incident (consistent with the corresponding static analysis).
- A modification of the above scenario to include an additional reduction of 200 MW of wind farm output immediately following the loss of the fourth transmission line. As discussed in Section 2.3, it is quite likely that high wind speeds were present in the Hallett area in the period immediately following the sixth fault.
  - The results under this scenario indicate the SA power system would have remained stable and separation from the rest of the NEM would not have occurred. Detailed results of this simulation are in Appendix M.2.

A third scenario was considered for a situation where, prior to the faults, AEMO had reclassified the simultaneous loss of six 275 kV transmission lines, subsequently advised by ElectraNet as potentially vulnerable lines to high wind speed conditions, as a credible contingency event due to high winds. As set out in Chapter 2, AEMO was not advised of any specific risks to these transmission lines prior to this event.

The analysis concluded that any such reclassification prior to the event would not have prevented the Black System. Details are in Appendix M.3.

Heywood Interconnector transfer capability

The following key observations can be made about the transfer capability between South East and Heywood circuits (see Appendix M.1.1):

- 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 80).
- Line outages in the Davenport area:
  - Have no material impact on Heywood transfer capability. Comparison of Figure 81 and Figure 82 provides further evidence that the loss of these lines would likely have had no noticeable impact on reactive power margin at South East substation.
  - Would have been unlikely to have resulted in a noticeable voltage decline at South East area. Figure 81 and Figure 82 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.1.1):

- Line outages in the Davenport area would likely have impacted the ability to maintain Davenport voltages. Comparison between Figure 84 and Figure 85 illustrates a reduction in reactive power margin at Davenport with the loss of three and four lines. 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 83).[63]
- 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.1.1):

- Line losses in the Davenport area would likely have had no adverse impact on Robertstown to Adelaide transfer capability, as shown by Figure 86.
- Comparison of Figure 87 and Figure 88 provides further evidence that losses of these lines would likely have had no noticeable effect on reactive power margin at Para, which is a critical bus that supports Adelaide demand.
- Line losses 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 87 and Figure 88.
- Line losses 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.

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)[64], as well as more detailed weighted short circuit ratio (WSCR) calculations (see Appendix N).

Table 12 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.

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[63] 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.

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

Table 12 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 2	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 (OEM) 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 three or six 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 has been investigated further, as set out in Appendix X.3.1. AEMO's investigations have indicated that when SA is islanded with a moderately low level of synchronous generation, the system strength at the HV terminals of wind turbines for a number of wind farms will fall below their minimum design level. This means that the wind turbines at these locations may not be able to ride through credible voltage disturbances, creating additional risks for islanded operation.

AEMO also investigated the impact of low system strength on protection operation, as set out in Appendix X.3.4. These investigations show that, for islanded operation with moderately low levels of synchronous generation, more than 10% of transmission line protection can be prone to mal-operation or failure to operate conditions.

3.6 Conclusions

Electrical faults

Close inspection of the BOM's report[65] and AEMO's internal review of lightning protection data 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.

[65] BOM. *Severe thunderstorm and tornado outbreak South Australia 28 September 2016*. Available at: http://www.bom.gov.au/announcements/sevwx/sa/Severe_Thunderstorm_and_Tornado_Outbreak_28_September_2016.pdf.

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. The pre-set protection limit for these wind farms was unknown to 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, and an additional temporary loss of 42 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 experienced minor levels of temporary over voltages, before the rapid frequency fall led to the Black System.

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 the 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. The frequency dropped below 47 Hz in most parts of the SA island, at which point synchronous generators and wind farms are not required to remain connected (see 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 if the RoCOF was low enough to ensure successful operation of UFLS scheme, resulting in 60% of SA load being shed before frequency fell to 47.0 Hz. This is because the remaining load of approximately 800 MW, after UFLS action, may still have been 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

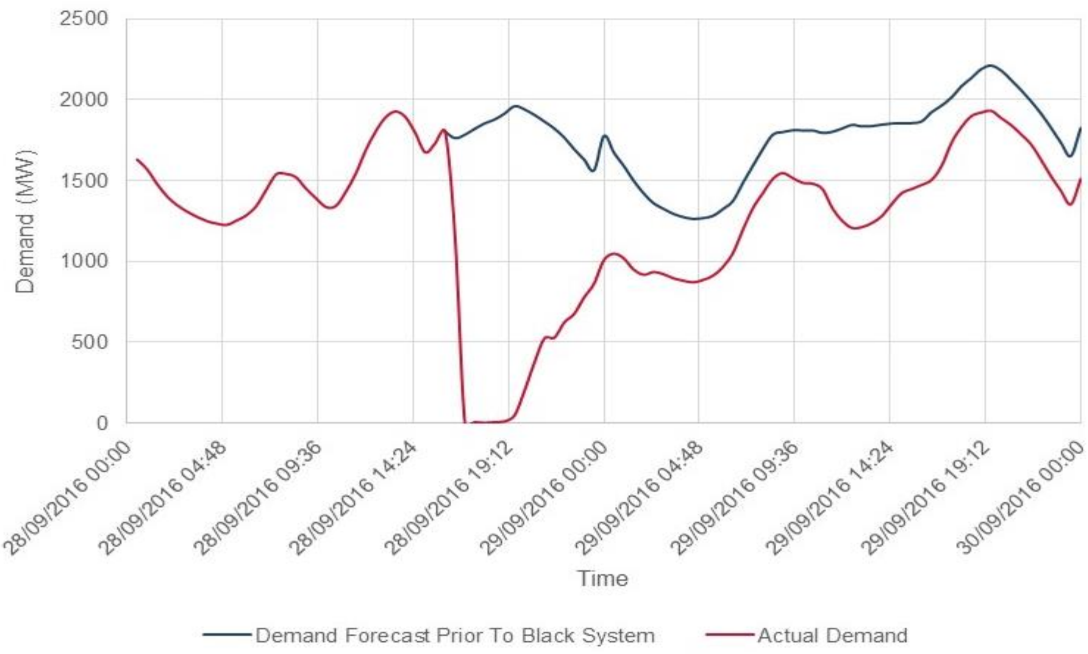
This chapter sets out the roles and responsibilities of the different organisations involved, and details of AEMO's restoration strategy used to restore the power system and load in SA. More detail on the restoration process is in Appendix Q.

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.

Where information has been updated since AEMO published the previous report in December 2016, these points are highlighted.

To summarise, Figure 23 illustrates the restoration of consumer load following the 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, distribution network service providers (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[66] at Quarantine Power Station[67] (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[68], 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 Chapter 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.

[66] 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.
[67] See Chapter 5 for further information on the SRAS.
[68] 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 owners (AusNet Services and ElectraNet) prior to reaching this conclusion.[69]
- 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 13 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 13 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, 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

[69] Amended from information in the third report to make it clear that AEMO consulted with ElectraNet as well.

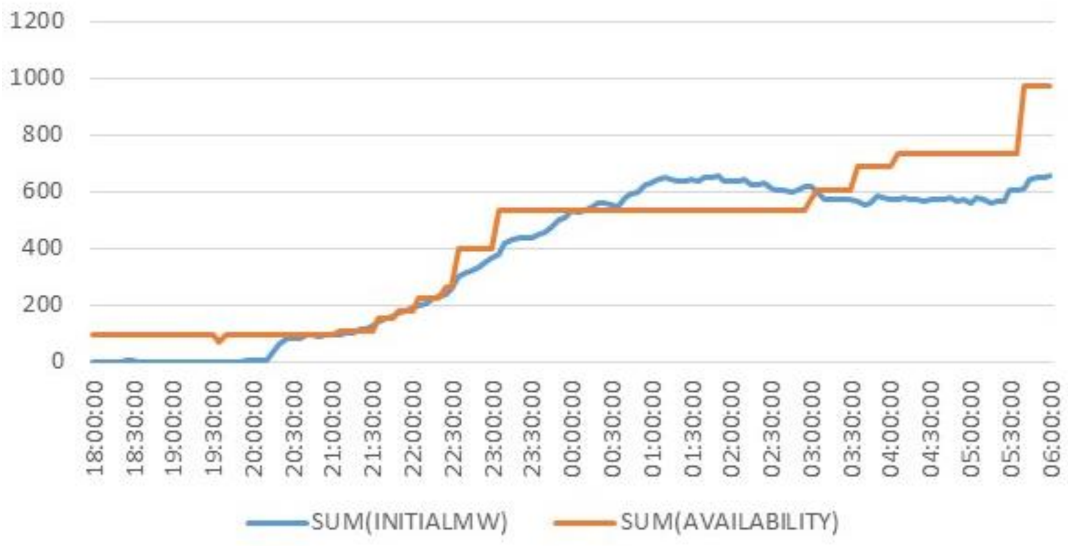
approximately 2.5 hours after auxiliary supply was restored, and six hours after the restoration process commenced.

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 13 versus the availability of the units.

Figure 24 Total unit generating MW output versus availability



Attempts were made to start the Dry Creek Power Station[70], 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[71] 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.

[70] Dry Creek Power Station has three 45 MW gas turbine units.
[71] AGL SA Generation Pty Ltd is the operator of the Torrens Island A & B power stations.

4.3.2 Port Lincoln area

This section is based on information provided by ElectraNet and ENGIE.[72]

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

On 27 September 2016, in advance of the extreme weather event, all three Port Lincoln units underwent successful test runs. During this testing, all of the units successfully synchronised and no alarms, trips, or failed starts occurred.

Following the Black System, ElectraNet advised ENGIE that the Port Lincoln generating units were to be started in accordance with its Network Support Agreement.[73] 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.

Following the Black System, ENGIE has investigated the operation of the Port Lincoln units during the event and subsequent restoration.

The failure of units 1 and 2 resulted from extreme weather conditions, including extreme rainfall, wind and lightning strikes. Unit 3 was subsequently forced to be taken offline when stability issues were experienced (these stability issues were only experienced following the trip of units 1 and 2).

ENGIE has subsequently carried out a number of actions, including review and adjustment of the control systems related to the frequency control response on unit 3, procuring a new replacement generator CB for unit 3 and enhanced monitoring of the transformer terminal box to avoid future moisture ingress.

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.[74] 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.[75]

[72] Synergen Power Pty Ltd is the operator of the Port Lincoln Power Station. ENGIE S.A. is the majority ultimate owner of Synergen.
[73] 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.
[74] This limit was based on conservative estimates of the system capability at the time. The limit was increased to 400 MW at 2050 hrs.
[75] Or approximately 64% of the load at the same time the previous day.

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 14 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.

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 14 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.

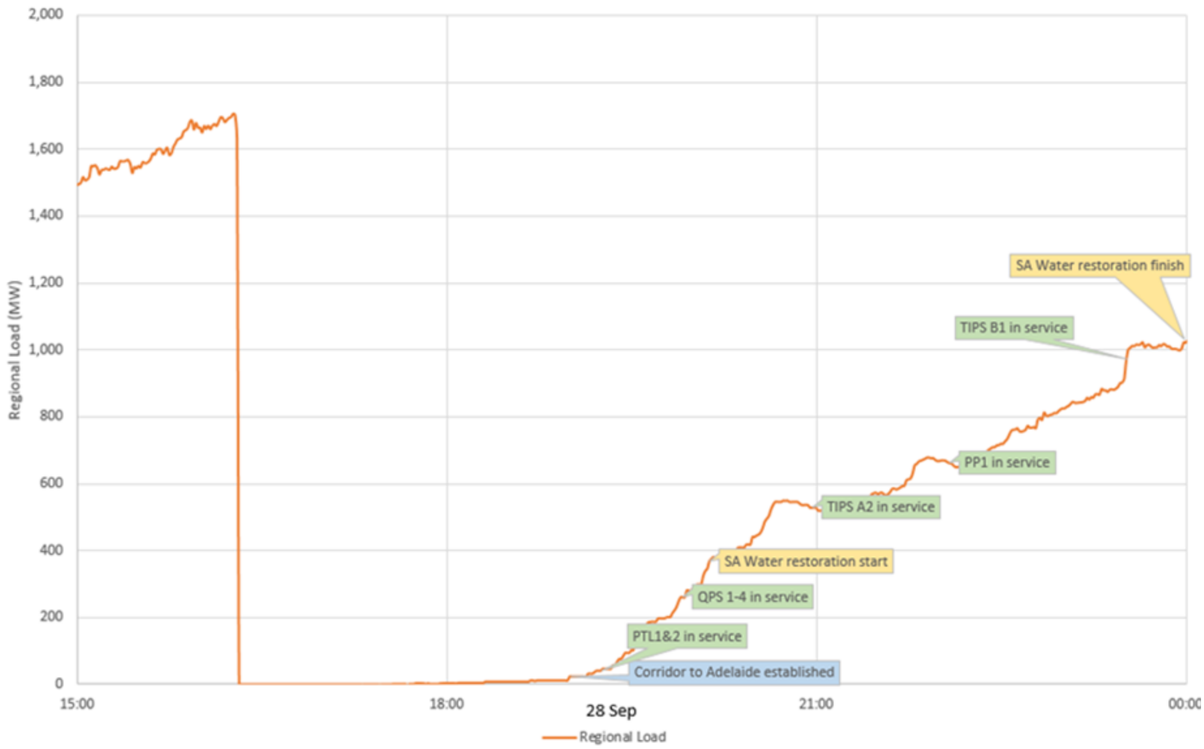
There were other factors preventing the use of local generation:

- Prior to 1215 hrs on 29 September 2016, there was no connection from the south to Davenport. With the Yadnarie to Port Lincoln line out of service, Mt Millar Wind Farm would have been the only generation available in the isolated system containing Port Augusta and Whyalla. It would have been impossible to restore or maintain this island from this wind farm alone, because wind turbines (and all other power electronic interfaced generation) require a stable voltage source before they can connect to the network.
- Similarly, Cathedral Rocks Wind Farm would not been able to restore or maintain supply to the isolated load in the Port Lincoln area.
- Following return to service of the first line to Davenport, system strength was very low in the Eyre Peninsula. Return to service of the Cathedral Rocks and Mt Millar Wind Farms was delayed until there was confidence that they could operate stably. This stems from the requirement for a minimum fault level in the network before wind farm transformers can be energised and the individual wind turbines can be connected and operate stably.

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

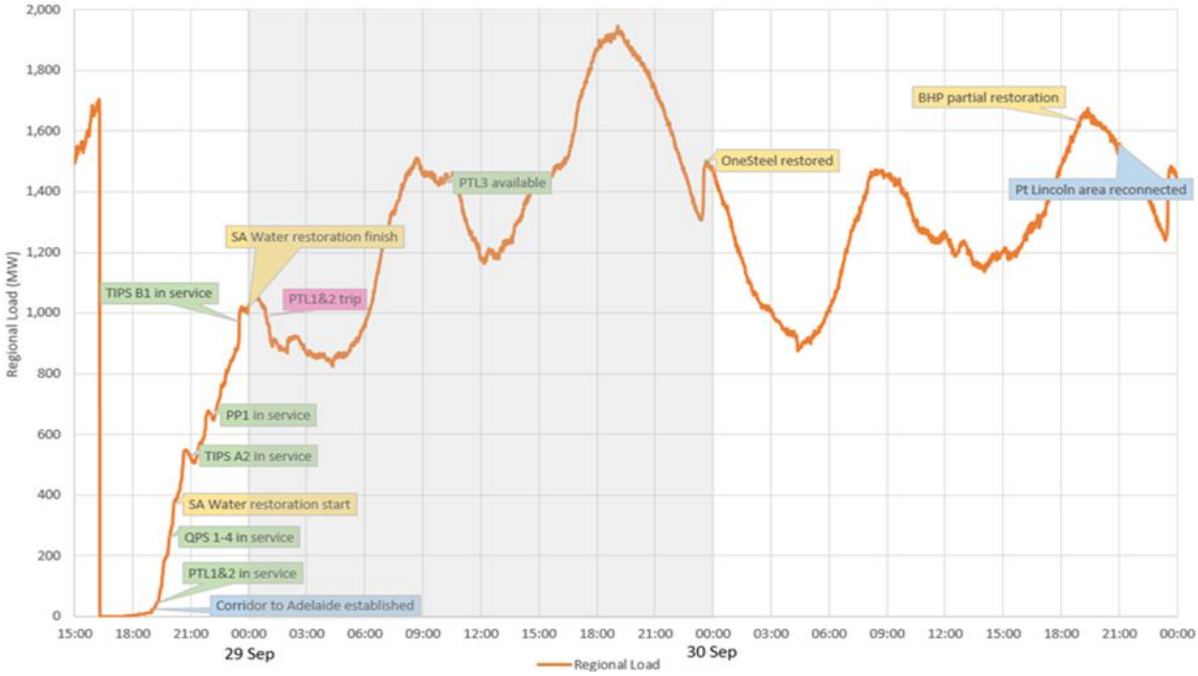
Appendix U provides an overview of the progress of load restoration in the Adelaide metropolitan area.

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



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, listed in Appendix T.2.[76]

4.6 Conclusion of the Black System

In accordance with AEMO operating procedures[77], 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.

[76] Appendix T provides links to AEMO's market notices and media releases on the AEMO website.
[77] SO_OP 5000 – System restart Overview.

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.

Table 15 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_5voNkw7bleOrQ2_Xg.

5. SYSTEM RESTART ANCILLARY SERVICES

This chapter reviews the performance of SRAS in SA during the Black System. See 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.

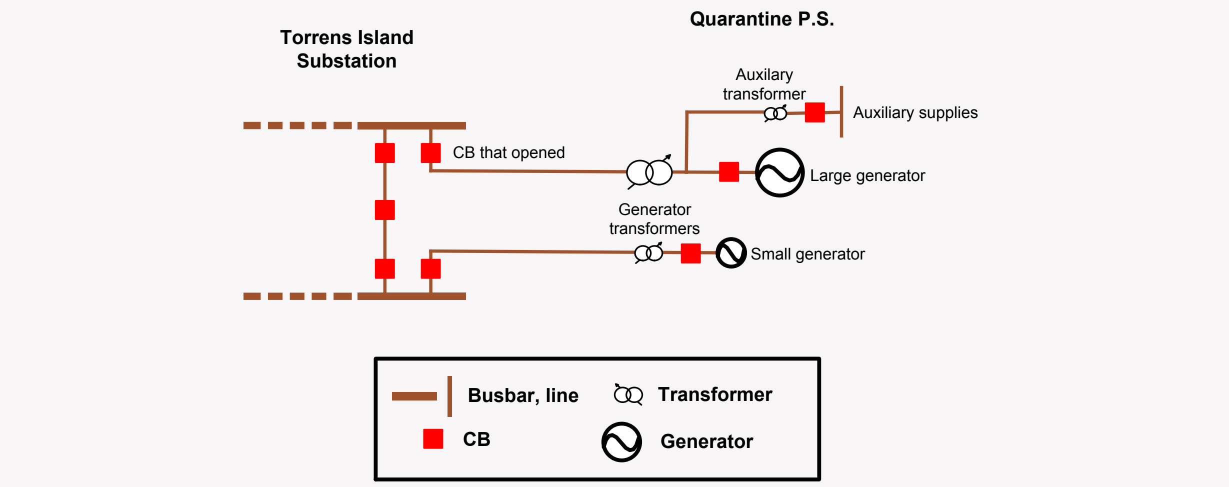
Investigation of the failure of the QPS SRAS concluded that the cause was related to the switching sequence used by ElectraNet to connect the small generating unit to the larger one.

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.[78] 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.

[78] 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.

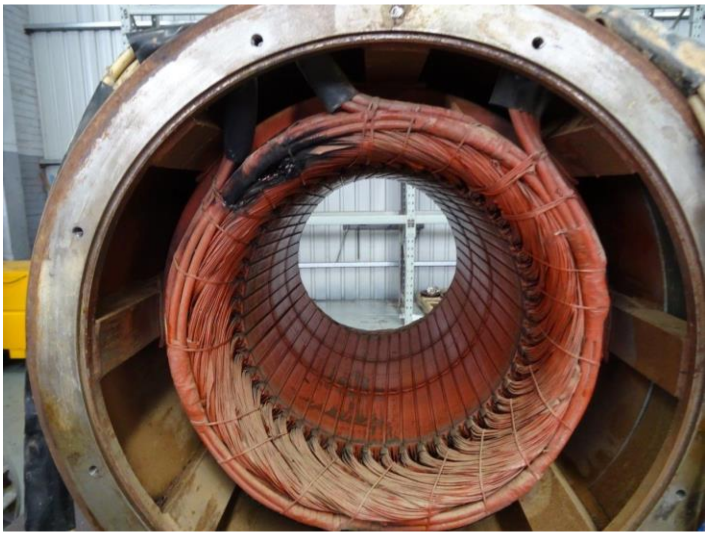
5.2 Performance of SRAS from Mintaro

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.[79] Although not conclusive, this is highly suggestive of lightning being the cause of the fault.

Figure 28 Damage to Mintaro diesel generator stator windings



[79] 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.

The faulty diesel generator had been repaired and a successful test of the Mintaro SRAS was conducted on 14 March 2017.

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.

Mintaro can be used as an SRAS 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 chapter outlines the market and system operation during the SA market suspension, and subsequently to 8 March 2016 for those issues that were specific outcomes of this event.

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, 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.[80]

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 16 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.

[80] 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 16 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.[81]

[81] 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.

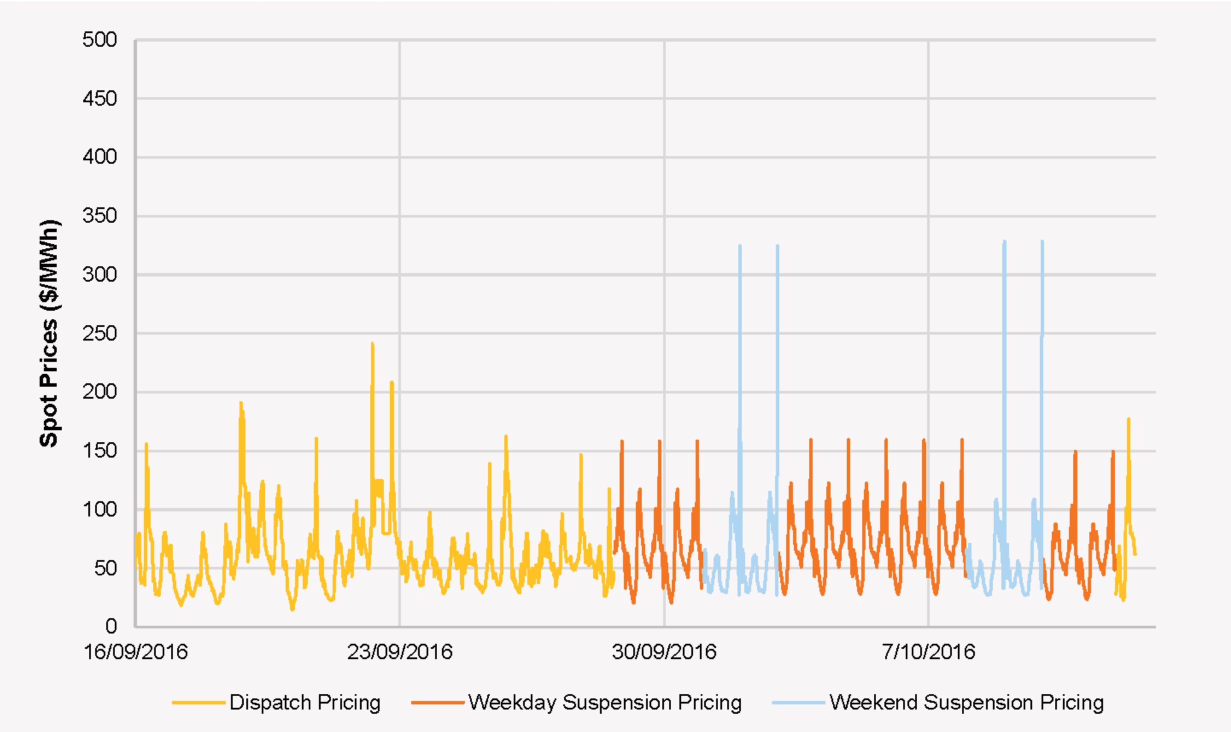
While the suspension was in effect, all normal market settlement, prudential, and compensation processes were applied using the revised market prices.

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.[82]

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.[83]

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.

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

During the full suspension period from 28 September to 11 October 2016, 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.

Table 17 provides price revision statistics each day during market suspension. Full details of the price revisions are available on AEMO's website.[84]

Table 17 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 synchronous generating unit in SA at 2054 hrs on 9 October 2016, instructing the unit to generate at 160 MW between 0000 hrs and 0530 hrs on 10 October 2016.

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

- A direction was issued to the operator of a synchronous generating unit in SA 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.[85]

6.5 Dispatch mechanism during market suspension

6.5.1 From 30 September 2016 until 4 October 2016

On 30 September 2016, AEMO implemented an operational strategy for generation dispatch during market suspension. This provided 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 by AEMO and shared with affected Registered Participants at industry conferences 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.[86] 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

While the root cause of the system collapse was still unknown, AEMO had to take all necessary precautions to maximise its ability to maintain power system security and reliability.

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

In conjunction with the headroom on the Heywood Interconnector, dispatch constraint equations were applied to ensure that the maximum single credible contingency event in SA was limited to 240 MW.

[85] 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.

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

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 6 October 2016.

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:

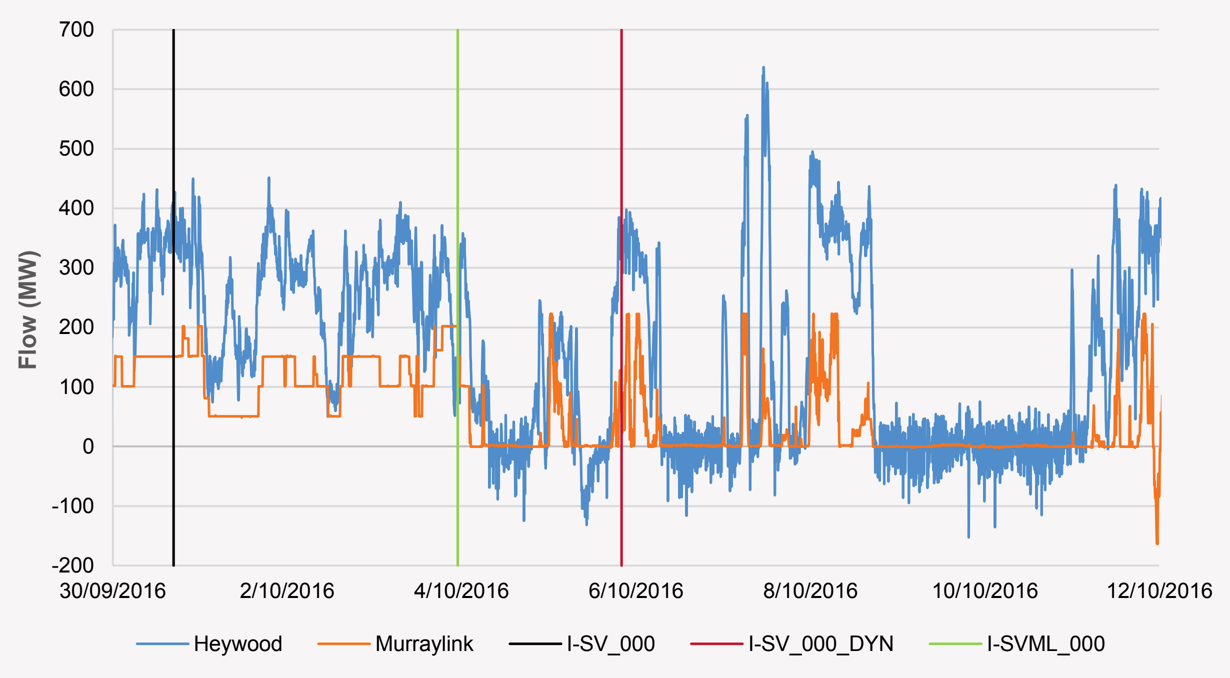
- Heywood Interconnector 0 MW limit (SA to Vic). Constraint Set I-SV_000_DYN.

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 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[87] 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. Table 18 details the reclassification changes.

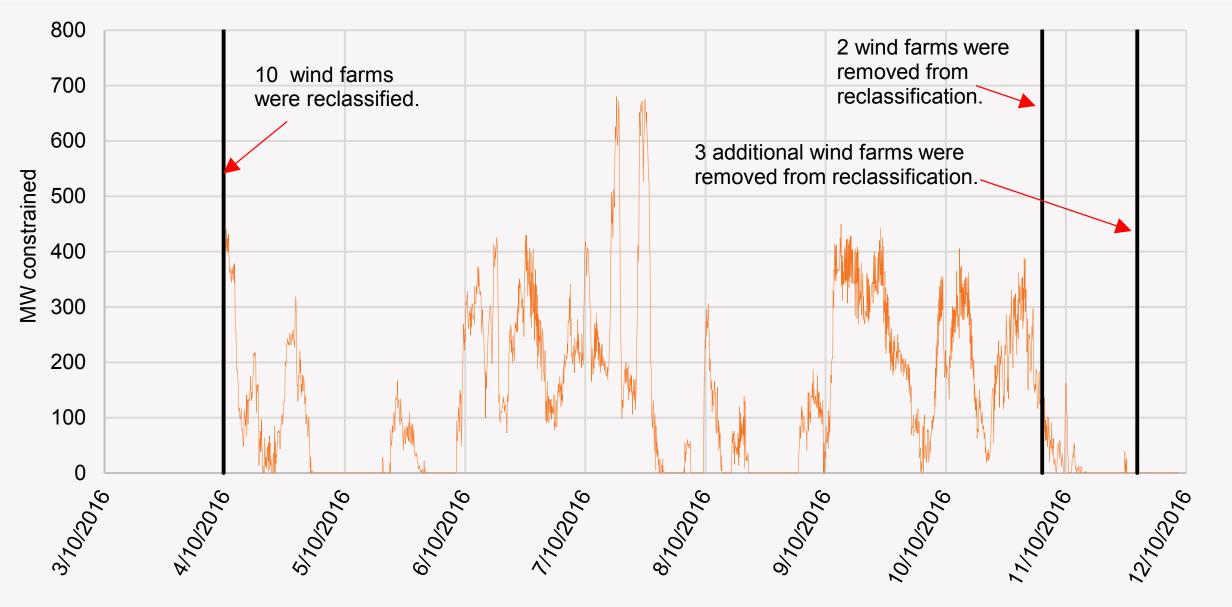
Table 18 Wind farm reclassification changes

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
24 December	Removed	Bluff Hallett Hallett Hill North Brown Hill	56434

Five wind farms remained in the reclassification after this amendment.

Figure 31 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



Due to AEMO's 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.[88] 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.

[87] 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*".

[88] 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 in SA 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 in SA 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.

Table 19 summarises of the number of large synchronous generators on-line during the market suspension period.

Table 19 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.[89] When all regions are synchronously connected, FCAS can be sourced from any region to meet global (NEM-wide) requirements.

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 market suspension pricing. In particular, the central dispatch process cannot optimise services across

[89] The minimum timeframe for FCAS delivery is over six seconds, that is, much longer than the quarter of a second the SA frequency took to collapse.

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:

- Expected RoCoF of the SA power system, in relation to the non-credible contingent trip of both Heywood Interconnector circuits, 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.

Table 20 shows the proportion of time the constraint equations V_S_NIL_ROCOF and S_V_NIL_ROCOF bound from 5 October 2016 to 9 March 2017.

Table 20 RoCoF constraint action

Constraint equation	Number of binding intervals (DIs)	Proportion of time the constraint bound (approximate)
V_S_NIL_ROCOF	5982	15%
S_V_NIL_ROCOF	68	0.2%

On 12 October 2016, regulations were made in SA[90] 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.

[90] *Electricity (General) (Provision of Limit Advice) Variation Regulations 2016* (SA). Available at: https://www.legislation.sa.gov.au/LZ/V/R/2016/ELECTRICITY%20(GENERAL)%20(PROVISION%20OF%20LIMIT%20ADVICE)%20VARIATION%20REGULATIONS%202016_240/2016.240.UN.PDF.

6.12 Resumption of market operation

AEMO took two steps during the suspension period 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 requested that SA Market Participants follow instructions being issued by its central dispatch system.

This orderly resumption was achieved by ensuring the Generators bid appropriately, ensuring the DFS and AWEFS was functioning correctly and ensuring all constraint equations reflected the then-current technical envelope.

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.[91]

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

7. RECOMMENDATIONS

The Black System has raised a number of direct questions around the management of the power system and the performance of generation in SA. It also raised broader questions of the resilience of the SA power system in the context of the changing generation mix, and that was, in part, responsible for the outcome the Black System.

Chapter 7 explores the lessons that can be learned from each stage of the Black System, the actions AEMO recommends, and the measures AEMO is putting in place to address these issues.

Where each root cause is identifiable, current initiatives to address the challenges are outlined.

Where relevant, this chapter also notes which recommendations have been added or updated since the third report.

AEMO is also continuing work to assess the longer-term needs of the NEM. This work is discussed further in Chapter 8.

7.1 Scope of recommendations

These recommendations 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 NER changes under consideration by the Australian Energy Market Commission (AEMC).
- The *2016 National Transmission Network Development Plan* (NTNDP).
- Any known proposals being made by other parties such as ElectraNet and the SA Government.

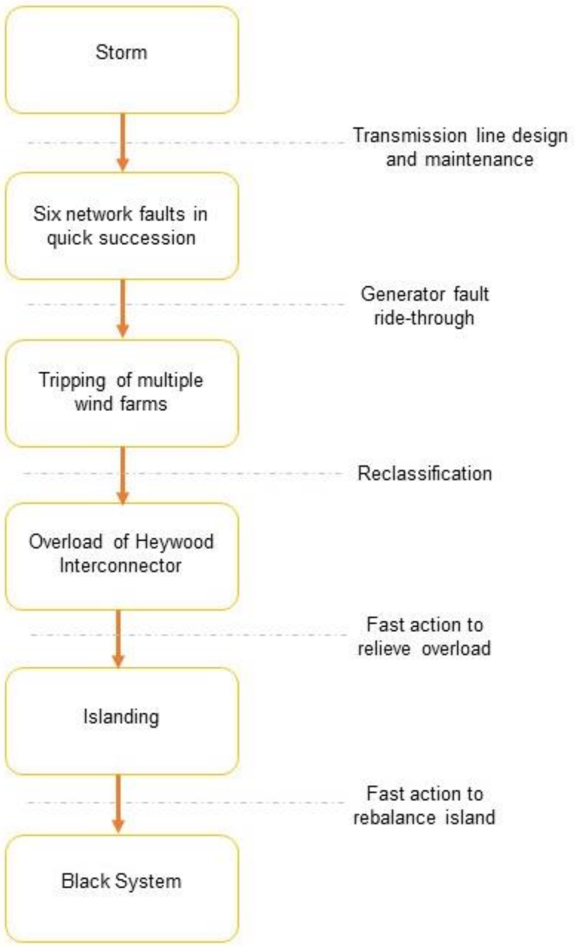
These recommendations do not cover areas that are outside of the scope of AEMO's responsibility for the SA region, such as asset design and maintenance.

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.

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.

Figure 32 Summarised chain of events and potential mitigating measures



7.2.1 Transmission line design and maintenance

Issues related to design standards of transmission line lines and maintenance practices are outside of the scope of this report. The design standards and maintenance standards are the responsibility of the TNSPs. These standards and practices take into account the need to strike a balance between cost and performance.

7.2.2 Generator performance standards

AEMO's investigation since the third report has highlighted the need for changes to generator performance standards in the following areas:

- Reactive output of generators during fault conditions.
- Ability of generators to remain in service through multiple voltage disturbances.
- Generator over voltage ride-through capability.[92]
- Requirement for generators to be capable of stable operation whilst system strength remains above a level specified in the access standard

More generally, the investigation has highlighted the need to:

- Have performance standards that describe unambiguously the expected performance of each generating system/unit.

[92] See Appendix X.4.

- Assess the performance of the power system for a plausible sequence of faults over a short period of time that would be more onerous than a trip reclose and lockout cycle – perhaps linked to the concept of 'protected events' (discussed further in Chapter 8).[93]

It should be noted that these recommended changes would, based upon current policy, only apply to new generators, so it would be a long time before the major benefits of these changes would be realised. However it is possible that costs of complying with some aspects of these proposed changes could be low even for existing generators. For such aspects the extension of new requirements to existing generators should be considered.

Recommendation 1 (new in this report)

AEMO to provide recommendations by early April 2017 to the Essential Services Commission of South Australia (ESCOSA) regarding changes the generator licensing conditions in SA.

Further, AEMO to submit a Rule change proposal to the AEMC by July 2017, requesting changes to Schedule 5.2 of the NER to address the generator performance standard issues raised in this report.

7.2.3 Reclassification

Awareness of updated weather forecasts

As indicated in Section 2.5, an update to the weather forecast received by AEMO later in the day did not trigger a reassessment of power system contingencies. While AEMO's post-event analysis indicates that 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 2

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.

This process has now been established.

Update on actions from this recommendation:

- In addition to operations planning staff, severe weather warnings are now also sent directly to the AEMO control rooms.
- Routine weather information available to the control room now contains a section on weather warnings.
- A training package has been developed to improve the ability of control room staff to interpret the warnings as they are received and assess the risks they pose to the power system.
- Training of staff is currently underway.
- BOM staff are available to NEM control centres.

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

[93]For a protected event, AEMO will be able manage the system at all times so that the frequency will stay within defined limits, if the protected event were to occur. This may include ex-ante actions, such as procuring ancillary services and constraining the dispatch of generation in the system. Some load shedding will also be allowed to limit the expected consequences of the protected event, if it occurs.

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 the 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.[94]

In 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, from excessive wind loading and from flying debris.

Recommendation 3

AEMO to work with the PSS Working Group[95] 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 will be put forward for consultation with participants and other relevant parties such as weather service providers.

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

Update on actions from this recommendation:

- Work with the PSS Working Group to develop processes for information exchange and reclassification decisions due to high wind speeds has commenced.
- The first key step is to identify transmission assets in each region that have been impacted by high wind or extreme weather events in the past, and look at the environmental conditions that were present (if possible) for those events.
- TNSPs are aiming to identify the impacted assets by end of March 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.

[94] For instance, during Cyclone Marcia in February 2015.

[95] 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 4 (new in this report)

AEMO to develop measures to better manage risks to power system security 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. In particular, to:

- **Provide the historical likelihood/frequency that a significant ramping event may take place by region. It is planned to compete this by 31 May 2017.**
- **Provide a forward looking forecast that a significant ramping event is likely to occur. This is a complex prediction in terms of modelling methodology. It is planned to compete this by 30 September 2017.**

This recommendation replaces the previous Recommendation 3, which proposed a risk assessment, and is the result of this risk assessment being completed.

Update on actions:

- AEMO is currently investigating multiple approaches that may improve AEMO's ability to predict a significant change in wind farm generation over the short term (0 to 6 hrs). One cause of significant change in generation is extreme wind cut-out, which occurs when the wind speed exceeds a turbine's rated survival speed, above which the turbine will be damaged. Another cause is a sudden increase or decrease in wind speed, which is not always foreseen by weather forecasters.
- AEMO has engaged its Australian Wind Energy Forecasting System (AWEFS) vendor to deliver a proposed methodology to predict a significant change in generation and alert the control room. A proposal is expected by the end of March 2017.
- AEMO has been approached by vendors who presented possible technological solutions that are currently in the feasibility stage. AEMO intends to work with the Australian Renewable Energy Agency (ARENA) to determine if a technological solution currently exists that addresses the issue.

Reclassification to manage 'type' risk

Traditionally, non-credible multiple generating unit contingencies have resulted from:

- Faults in power station switchyards affecting multiple generating units at that station.
- Unusual failures of power station auxiliary supplies affecting multiple generating units at a single power station.
- A voltage disturbance resulting in a number of generating units being unexpectedly unable to ride through the disturbance.

There are generating systems consisting of many mass-produced smaller generating units with, often, a particular model of generating unit common to a number of generating systems. Thus, a feature or fault for such a model could result in a large number of smaller generating units across multiple generating systems tripping simultaneously. As a result, AEMO may need to develop a new form of reclassification process to manage such risks.

Such a process may be quite different to traditional reclassification processes, and might have similarities to processes used in the aircraft industry to manage 'type' risk.

Recommendation 5 (new in this report)

AEMO to consider developing a new reclassification process to manage 'type' risk, including how information of potential risks will be sought and the most appropriate methods to manage power system security during such a reclassification.

AEMO to assess the level of potential risk in this area by December 2017.

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 SPSs has now reached a level that it could be feasible to develop schemes that could:

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

AEMO's investigations[96] since the third report have indicated that this may be feasible and is worthy of further consideration. The main challenge is ensuring secure operation of the scheme while still achieving the required response time for it to be effective in preventing islanding.

Recommendation 6 (updated based on progress to date)

In consultation with ElectraNet, AEMO to investigate the feasibility of developing a special protection scheme that would detect sudden excessive flows on the Heywood Interconnector or serious events within SA and initiate, if necessary, load shedding or generation response[97] with a response time fast enough to prevent separation.

AEMO will commence investigations with ElectraNet regarding feasibility in April 2017.[98]

7.2.5 Fast action to rebalance the island

If the SA region forms an island, 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 under frequency and 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 on the efficiency of the market and, ideally, should be replaced or supplemented by longer term measures that either do not require or reduce the need for pre-contingent arrangements.

Implementation of RoCoF UFLS relays[99]

As part of a review of the UFLS scheme for SA in 2016, it was recommended that a minimum of 15% of the load available to the UFLS be tripped on the basis of RoCoF. That is, 15% of the UFLS load would be tripped if the RoCoF is ≥ 1.5 Hz/s and the absolute frequency is ≤ 49.4 Hz. This will enable the UFLS to operate reliably for a RoCoF up to 3 Hz/s.

The key features of this option are:

- Since 15% of the load is shed sooner, this option effectively presents a smaller contingency with lower residual RoCoF to the remaining blocks of UFLS.
- For a NEM-wide under frequency event, it does not affect existing pain sharing arrangements.

The changes were implemented by SA Power Networks in February 2017 using existing relays.

[96] See Appendix Y.4.
[97] It is also possible that devices such as rapid response energy storage systems could be used.
[98] Implementation may also need to be supported by Rule Changes along the lines currently being considered, such as the concept of "Protected Events".
[99] 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 individual blocks that 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 conditions could be improved (if only marginally) if the requirement for equitable sharing is relaxed to some extent.

Since publication of the third report, AEMO has undertaken work, on the feasibility of an SPS[100] to rebalance the SA island rapidly, has shown that any such reallocation to make the UFLS action more aggressive would achieve little improvement to its effectiveness.

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[101] within the island, and must be done in a graded fashion, since over-shedding of generation would then lead to under frequency conditions.

Since the third report, AEMO, working with ElectraNet, has completed the design for such a scheme. Discussions are now underway with SA Generators regarding implementation.

Event-triggered frequency control schemes

The development of SPSs is such that it may be feasible to take effective action immediately after an islanding event is detected, rather than waiting until a significant frequency deviation is detected.

AEMO's investigations[102] since the third report have shown that:

- Such an SPS to rebalance the island, even acting with no time delay, would be ineffective.
- Such rapid load shedding may create severe over voltage issues.

For these reasons, such a proposal is not considered worth pursuing at this time. Priority should instead be placed on the development of a scheme to prevent islanding in the first place.

Special arrangements for frequency regulation

While not an issue for the cause of this event, AEMO's investigations since the third report have highlighted potential risks for frequency control if a stable island could have been established.

Even if an island is stabilised immediately, there is a need for frequency regulation services to be made available promptly. Measures to enable regulation services pre-contingency are in place to address this issue whenever there is a credible risk of islanding but not otherwise.

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[103], so no recommendations have been made in this area.

Availability of FCAS to manage contingencies

Whilst not an issue for the cause of this event, AEMO's investigations since the third report have highlighted potential risks for frequency control if a stable island could have been established.

[100] See Appendix Y.5.
[101] Disconnection of generating units with high inertia should be avoided.
[102] See Appendix Y.5.
[103] For more information, see http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/-/media/823E457AEA5E43BE83DDD56767126BF2.ashx.

Within thirty minutes of the island forming, the NER expect that there should be sufficient contingency FCAS 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, in relation to common response of generators during fault conditions and system conditions when SA is islanded, were identified during the investigation. AEMO's investigations since the third report have updated one recommendation and generated several new recommendations.

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.

AEMO's investigations[104] since the third report have shown that this is a real issue, and that the largest generator credible contingency under conditions of high wind generation is larger than currently assumed. This has led to a revision of the transfer limits for the Heywood Interconnector.[105] This will involve, in the short term, reductions in the transfer limits for import to SA to between 400 to 500 MW under conditions of high wind generation. In addition, the current maximum transfer level of 600 MW for import to SA, under any conditions, will remain in place at least until:

- Longer-term work with ElectraNet on review of transfer limits has been completed, and
- Work under recommendations 3, 4, and 11 to improve risk management processes has been implemented to an acceptable level.

Recommendation 7

AEMO, in the short term, to modify existing transfer limits to account for the findings of this investigation, so as to ensure secure operation of the SA power system.

In the longer term, AEMO to work with ElectraNet to further broadly review the transfer limits applied to the Heywood Interconnector, to fully incorporate the findings of this investigation, and ensure the ongoing security of the SA power system, while still allowing for the highest utilisation of the Heywood Interconnector, where it is secure to do so.

It is planned to complete the short-term work by end of March 2017.

This updates and replaces the previous Recommendation 7.

System strength and generator stability

AEMO's investigations[106] since the third report have shown that:

- When SA is islanded, the SCR may fall below design capability for a number of wind farms. This means the wind turbines at these locations may not be able to ride through credible voltage disturbances, creating additional risks. AEMO understands that tuning of the converter control

[104] See Section 3.3.
[105] The proposed changes to generator performance standards being considered by ESCOSA would reduce the risk in the future.
[106] See Section 3.5.2.

system in the wind turbine generators may enhance a wind turbine's capability to successfully operate under lower SCR conditions.

- Even when not islanded, the SCR may be below the design capability of Eyre Peninsula wind farms. This may create some additional risks, but these are not expected to be major.

The AEMC is currently consulting on a Rule change proposal that will ensure effective market or regulatory arrangements to procure system strength services in the NEM. AEMO is contributing to this work.

AEMO understands one question the AEMC is considering is whether is an obligation on NSPs may already exist under the NER to maintain some minimum level of system strength, although it is unclear how this minimum level is specified.

Recommendation 8 (new in this report)

AEMO to arrange for the issue of maintenance of adequate system strength be incorporated into the planning process for all regions in a more structured manner, similar to the NSCAS gap process.

AEMO to also take this risk into account in its operational procedures for operation of the SA region when islanded.

AEMO plans to complete the work to take this risk into its own operational procedures by end of June 2017.

It is planned to complete the work related to regional planning processes by December 2017, but this may first require changes to the NER.

System strength and protection relay operation

AEMO's investigations[107] since the third report have shown that when SA is islanded, system strength could now fall to such a level that it could impact on effective operation of some protection schemes.

Recommendation 9 (new in this report)

AEMO to support ElectraNet in a more detailed review to identify any specific risks to protection systems due low system strength when SA is islanded, and address them.

It is planned to complete the work by December 2017

Over voltages due to significant load shedding

AEMO's investigations[108] since the third report suggest that, following significant load shedding after separation, there is a risk of severe over voltages that could imperil the SA island under medium and low demand conditions.

Recommendation 10 (new in this report)

AEMO to support ElectraNet in assessing methods to manage the risk of severe over voltages following load shedding after separation.[109]

It is planned to complete this assessment by October 2017.

[107] See Appendix X.3.4.
[108] See Appendix Y.5.
[109] Enhancement of the over voltage rise through capability of generators, as proposed in Recommendation 1, will also assist.

Remaining risk for multiple voltage disturbances

AEMO has carried out a review of this risk[110], taking into account the recent changes in wind turbine settings.

The review indicated that these changes have improved the resilience of the SA power system[111], but a material risk may still remain for multiple disturbances over a thirty-minute period. Details of actual limits have also not be confirmed for a number of wind farms.

Recommendation 11 (new in this report)

AEMO to review its reclassification procedures to address the risk of a failure by wind farms to ride through multiple disturbances over a thirty-minute period, under abnormal conditions which are likely to make this risk significant.

AEMO to approach relevant Generators to discuss the feasibility of raising the limit for the number of LVRT events within a 30-minute period.

AEMO to follow up with a small number of remaining Generators to ensure information on the limit on the number of LVRT events within different time periods is confirmed for all wind farms in SA.

AEMO plans to review its reclassification procedures by November 2017.

AEMO plans to approach relevant Generators about the feasibility of raising limits for LVRT events by May 2017.

AEMO plans to confirm information with remaining Generators by May 2017.

7.3 Restoration

The focus of recommendations in this area is on measures that should improve the speed of restoration without increasing risk.

Recommendation 12

AEMO, with the SA System Restart Working Group, to review the system restart process in detail to:

- **Determine whether there are any:**
  - **Cost-effective measures that could be implemented to assess the situation more quickly or effectively 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 those deficiencies.**
  - **Cost-effective measures that could be adopted to speed up 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 during the restart process.**
  - **Improved processes to track the availability of system restart sources.**

[110] See Section 3.2.1.
[111] For instance, on 3 March 2017, all wind farms in service rode through a number of faults which occurred in quick succession.

- **Implement the recommendations made by the Reliability Panel as part of its determination on the System Restart Standard.**

These learnings will 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.

This recommendation updates the previous Recommendation 8, by adding the implementation of System Restart Standard recommendations made by the Reliability Panel.

Update on actions from this recommendation:

- A plan to address this recommendation was agreed at the SA System Restart Working Group on 31 January 2017. Different organisations within the working group are taking a lead in the various elements of the recommendation.

A major issue identified was that the operation of Quarantine Power Station failed due to the use of switching procedures during the restart that differed from those used to test it earlier in 2016.

Recommendation 13

In preparation for an SRAS test, the test plan to be compared by AEMO 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 practicable, 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 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 the SRAS provider.

These changes are planned to be adopted immediately.

Update on actions from this recommendation:

- The SRAS testing process has been updated to introduce the following process:
  - At the time of each SRAS test, AEMO will, in consultation with the SRAS provider, set out what is expected to happen in a real black system. This will be documented in the AEMO witness report.
  - These real event procedures and processes will then be compared to test procedures and processes.
  - Where the test and real procedures and processes are alike this will be recorded. Where they are different, the reason for the difference will be recorded and assessed against a real event process.
  - AEMO will either state that it is satisfied that the test process, as far as practicable, reflects the expected real event process, or identify gaps that require attention.
  - AEMO and the SRAS provider will assess these gaps to determine if they represent processes that, if failed, would reduce the likelihood a successful restart.
  - Any such gaps, if not practical to include in the test, will either be addressed before an SRAS test, or, if identified after the test, require either a repeat of the test, or amendment for the next test (depending on the significance of the gap).
- Despite a successful test earlier in the year, the Mintaro SRAS source was unavailable due to the failure of a low voltage generator. The low voltage generator failed shortly after it had stated in response to the black event. 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 14

Where an SRAS source depends initially on a start of a low voltage generator, 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.**

Update on actions from this recommendation:

- The SRAS testing process has been amended to introduce the following process:
  - Where the provision of SRAS depends on the start-up of a diesel generator, at the time of each SRAS test AEMO will ask the SRAS provider to submit evidence demonstrating that the diesel generator is operated periodically as part of a planned maintenance program.
  - This evidence may be maintenance records or time-stamped data trends that will then form part of the test report for the annual SRAS test.

7.4 Market suspension

7.4.1 System operation

The experience in market and power system operation gained during an extended market suspension highlighted a number of opportunities for improvement.

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

Recommendation 15

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

Update on actions from this recommendation:

- Work has started on identifying the procedures that need to be modified or created, with the aim of providing more comprehensive information on how the power system and market would be operated and priced during a market suspension.
- Work on the power system and market procedures is progressing in parallel, because power system operation and market operation are two sides of the same coin. However, the early focus has been on any potential NER changes and the consequences that these might have
- There were also specific difficulties with Generators receiving dispatch targets below the minimal stable load of their plant.

Recommendation 16

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

Update on actions from this recommendation:

- Work is underway on ways to cater for the minimum stable load of scheduled generating units in the central dispatch process.
- A key part of this work is balancing the need to maintain appropriate price signals, preserve technological neutrality, and avoid imposing undue costs on participants. AEMO notes that this is a market issue, rather than a market suspension issue, but recognises that the market suspension heightened the visibility of this issue.

7.4.2 Market operation

The known scope for improvements to market processes and systems, updated since the third report, includes:

- Automation of systems for pricing during a market suspension and related procedures.
- Rationalisation of the different pricing mechanisms during a market suspension.
- Clarification of procedures for directing during a market suspension.
- Review of procedures and systems for defining local FCAS requirements and for settling FCAS provision during a market suspension.
- Resolution of issues with SRAS settlement during a black system where there is no underlying energy as a basis to recover SRAS costs.
- Addressing other market system issues, including the processing and reporting of market suspension flags, market suspension pricing schedules, over-constrained dispatch, revisions to market suspension pricing schedules and participant database discrepancies.

Recommendation 17

AEMO to review market processes and systems, in collaboration with Registered Participants, to identify improvements and any associated NER or procedure changes necessary to implement those improvements. **It is planned to complete this work by end of June 2017.**

This recommendation covers a broad range of issues, of varying degrees of complexity and significance.

Update on actions from this recommendation:

- An early area of investigation has been the potential for harmonising the NER provisions on market suspension pricing with other price revision mechanisms in the NER. Other price revision mechanisms in the NEM include over-constrained dispatch, manifestly incorrect inputs, intervention pricing, administered pricing, and price-scaling between adjacent regions.
  - For example, harmonising the NER provisions on price-scaling would facilitate the automation of price-scaling during a market suspension. Any such automation would reduce manual workload and the attendant risk of human error during an extended market suspension.

7.5 Data issues

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

Recommendation 18

AEMO to develop, in consultation with Registered 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 them.

It is planned to complete this work by end of June 2017 but implementation may be dependent upon Rule changes.

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 the lack of a common time standard.

Recommendation 19

AEMO to investigate, with Registered 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 the end of September 2017. Further work will depend on the results of the investigation.

8. NEXT STEPS

All content in this chapter is new, and has not been included in AEMO's previous reports about this event.

8.1 Introduction

The Black System has raised a number of direct questions around the management of the power system and the performance of generation in SA. It also raises broader questions of the resilience of the power system in SA associated with the changing generation mix, whether or not those factors were in part responsible for the outcome on 28 September.

Building on the specific recommendations from Chapter 7, this chapter provides a brief overview of other relevant activities to improve the resilience of the SA power system, and the longer-term resilience of the NEM.

Each NEM region has unique characteristics including generation mix, structure of the local network, and level of interconnection. This means any short-term solutions applied in SA may not be transferable to the rest of the NEM.

In 2015, AEMO established the Future Power System Security (FPSS) program,[112] which takes a strategic approach to power system requirements.

The program addresses the need for efficient national solutions by analysing the technical challenges and solutions of the power system of the future, while building on the lessons learned from ongoing operational experience.

Full details of the FPSS program, including reports, publications, and a January 2017 Progress Report are available on AEMO's website.[113]

8.2 Ongoing investigations

In addition to the actions taken as a direct result of the Black System (Chapters 6.8 to 6.13 and Chapter 7), a number of other activities to improve the resilience of the SA power system were underway prior to the Black System. Progress is summarised below.

8.2.1 Exploring options to procure inertia and system strength in SA

While NEM-wide options are being explored for the procurement of inertia and system strength from synchronous machines[114] as part of the AEMC's System Security Market Frameworks Review, due to the time required to develop these changes, AEMO is pursuing options with ElectraNet for possible early investment in available solutions in SA.

8.2.2 Reviewing and updating technical standards for registered generators

AEMO is currently working with the Essential Services Commission of South Australia (ESCOSA) to review technical licence conditions for generation in SA, such that the SA generation fleet is armed with the capabilities it needs to provide a secure and resilient power supply for the life of the assets. AEMO will be providing its recommendations to ESCOSA by early April 2017.

AEMO considers that the generator performance standards in the NER require updating as soon as practicable, and intends to submit a Rule change to the AEMC requesting appropriate revisions. It is anticipated that the standards recommended for SA through ESCOSA's process would be a key consideration in determining the appropriate changes. Ideally, any new licence conditions imposed by

[112] The FPSS program website is at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.
[113] FPSS Reports and Publications, including January 2017 progress report: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis.
[114] A short overview of system strength can be found in the following fact sheet: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-Fact-Sheet-System-Strength-Final-20.pdf.
Following a system event in November 2016, new arrangements to maintain power system security during periods of anticipated low fault levels (low system strength) were implemented: http://www.aemo.com.au/-/media/Files/Media_Centre/2016/SA-System-Strength.pdf.

ESCOSA would be transitional arrangements that are eventually superseded by the NER. AEMO intends to submit this Rule change request by July 2017.

8.2.3 Exploring the response of existing generation and network equipment to extreme frequency changes.

The protection system response of groups of wind farms to successive faults indicates that AEMO does not have all the information it needs to predict accurately how the power system, and each element in it, will behave during more extreme power system conditions such as those observed in SA on 28 September 2016.

Some elements may have been designed under different technical requirements (prior to the NER for example), or may have protection settings that are designed to trip at a point unknown to AEMO.

AEMO is currently working to understand more about the settings of existing SA generation and network equipment related to withstand capability of high RoCoF. This will give AEMO crucial information to help manage power system security and resilience in the immediate and longer term.

8.2.4 Services to assist in system restoration

Recovery of a region from a black system condition relies on SRAS that are contracted for that purpose, and thus, for an islanded region, need to be local. This means that the changing generation mix may limit the number of eligible restart generators. Over the longer term, AEMO is looking to investigate the ability of non-synchronous generation to provide SRAS.

In the interim, through the ESCOSA licence conditions, AEMO is considering recommendations for whether new non-synchronous generation should have the ability to assist in system restoration following a black system event. While currently unable to provide SRAS, the contribution to voltage and reactive power control from non-synchronous generators could be important in system restoration, provided that a number of synchronous machines are already restarted that can provide the minimum fault level required for stable operation of non-synchronous technologies.

8.3 Regulatory and strategic initiatives

8.3.1 Short-term focus areas

The challenges of managing high RoCoF were outlined in the FPSS program progress report released in August 2016[115], and are being pursued by AEMO and through work being carried out in collaboration with the AEMC.

In parallel with short-term activities in SA, AEMO is progressing a number of relevant actions over the short term including:

- Collaborating with the AEMC on a Rule change proposal that considers a new regime to implement Emergency Frequency Control Schemes (EFCS) that would manage the system frequency when it is in the extreme band.[116] This Rule change proposal also considers the introduction of a new category of contingent risk in the network referred to as ‘protected events’. This includes a risk assessment framework to review low probability events that could have a high impact, and assess if there is an economic case to take some form of action to mitigate the risk.
- Collaborating with the AEMC on a Rule change proposal considering the potential future need for new market or regulatory arrangements to procure system strength, inertia and fast frequency response services.
- Reviewing the specification and design of all FCAS to ensure AEMO can obtain services in the future from non-traditional sources.

[115] AEMO. FPSS program progress report. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/FPSS---Progress-Report-August-2016.pdf.
[116] Draft determination available at http://www.aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen/Draft-Determination/AEMC-Documents/Draft-Rule-Determination,-Emergency-Frequency-Cont.aspx.

- Assessing the future needs of power system services ancillary to energy to test the adequacy of current frameworks and/or design new ones.
- Developing more structured processes to source and capture data after major events.

8.3.2 Medium-term focus areas

Establishing arrangements to get access to improved data on DER

AEMO only has access to data related to generation and load that is owned by Registered Participants. The change in generation mix has seen an increase in the proportion of distributed energy resources (DER), the owners of which do not participate directly in the wholesale market as most do not meet the plant size thresholds for registration. AEMO has little to no visibility of the location or operation of DER.

A lack of information about DER poses a number of risks to power system security. For example, DER that is connected to the network via inverters are pre-set to respond in a certain way to system disturbances.[117]

With increased penetration of different types of DER, understanding how they will behave is critical to power system security. Given the volume of inverter-connected small-scale PV generation in the NEM, and the lack of information on how it will respond to frequency disturbances, in 2015 AEMO initiated a stocktake of the then current fleet of inverters and their frequency trip settings[118] to ascertain whether they would respond simultaneously to frequency disturbances by disconnecting at a set frequency.

The data collected indicated a low probability of inverters tripping in unison due to frequency disturbances within the required frequency operating ranges. Limitations in the data obtained, however, mean concern remains over the reliability of the conclusions that can be drawn.

Need for proof of concept

While the NEM has successfully dispatched and co-optimised markets for energy and ancillary services for many years, the current mechanisms may not deliver the services required for the future as traditional providers of synchronous generation retire. Furthermore, with the change in generation mix, the ancillary services required into the future go beyond those currently procured, and include services such as inertia and fast frequency response.

The future power system will need services from non-traditional sources like utility-scale solar PV, wind farms, batteries, and importantly from DER such as ‘behind the meter’ facilities installed in customer premises. Like all technology development, there is a need to support early deployment to ensure potentially attractive solutions can be both technically and commercially deployed in the NEM. In this respect, support for ‘proof of concept’ projects to better integrate new technologies into the grid will improve the overall resilience of system in the future and support an efficient and effective transition.

AEMO will work with the Australian Renewable Energy Agency (ARENA) and others seeking to test and demonstrate:

- The value of new services such as fast frequency response to contribute to power system security and the ability to source those services from a range of technologies, potentially including:
  - Batteries and other storage technologies.
  - Inverter connected generators.
  - DC interconnectors.
  - Supercapacitors.
  - Improved traditional sources such as synchronous condensers, rotating stabilisers, and flywheels.

[117] See *AEMO, Visibility of Distributed Energy Resources* for further examples. Available at: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/AEMO-FPSS-program----Visibility-of-DER.pdf.

[118] *AEMO, Response of existing PV inverters to frequency disturbances*. Available at: http://aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

- The potential use of aggregated services from 'behind the meter' demand management, distributed generation, and battery storage control to provide security services to the grid.

The ability to test and demonstrate the capability of various technologies to provide the required system services will facilitate the efficient and effective development of operational, regulatory, and market frameworks necessary to deliver future power system security.

8.4 Power system modelling and analysis activities

8.4.1 Power system modelling and simulation

Increased modelling requirements

Managing power system security relies on understanding how the system behaves dynamically through a suite of power system models and tools. With the change in generation mix from synchronous to non-synchronous generation, the dynamics of the power system are also changing.

This means accurate modelling requires more granular (detailed) data from Generators about how their plant behaves. Better modelling allows AEMO to prepare and manage disturbances in the system to maintain power system security. Since early 2016, AEMO has been requesting more detailed models from Generators seeking to connect to the NEM where there is an assessed need for these models.

AEMO lodged a Rule change proposal in November 2016 to update and broaden the scope of Generating System Model Guidelines (GSMG), and is set to undertake a subsequent review of the GSMG in recognition of the growing importance of aspects of the power system, such as embedded generation, voltage support equipment/control, and protection systems, on AEMO's role as system operator. AEMO considers that these are not adequately addressed by the current GSMG.

The key objectives of this Rule change proposal[119] are to allow for:

- Broadening the GSMG and datasheets to include non-generating system power system elements.
- More detailed and accurate modelling and simulation of the power system to manage power system security with rapidly changing power system dynamics and generation technologies.
- More efficient procurement of ancillary services, and more accurate understanding of the technical capability of plant for the provision of new ancillary services.

Additionally, AEMO, in consultation with relevant Generators and ElectraNet, will obtain improved simulation models that more accurately represent generating system performance. This applies to a number of wind farms and synchronous generators in the SA power system, many of which are currently working with AEMO in this regard.

Power system modelling and simulation studies

Extensive power system simulation studies presented in this report focus primarily on the following scenarios:

- Black system operating conditions.
- Black system operating conditions, but assuming that wind farms did not reduce output due to the multiple voltage disturbances.
- Black system operating conditions, but assuming that wind farms did not reduce output due to the multiple voltage disturbances, and with a loss of 200 MW of wind generation output due to high wind speeds.
- Three TIPS B and two Pelican Point CCGT units online with approximately 1,400 MW of wind generation (see Appendix X.1.1 for more details).

AEMO will undertake additional power system simulation studies considering a wider range of operating conditions, and generation dispatch pattern so as to modify operational procedures.

[119] See http://www.aemc.gov.au/Rule-Changes/Generating-System-Model-Guidelines.

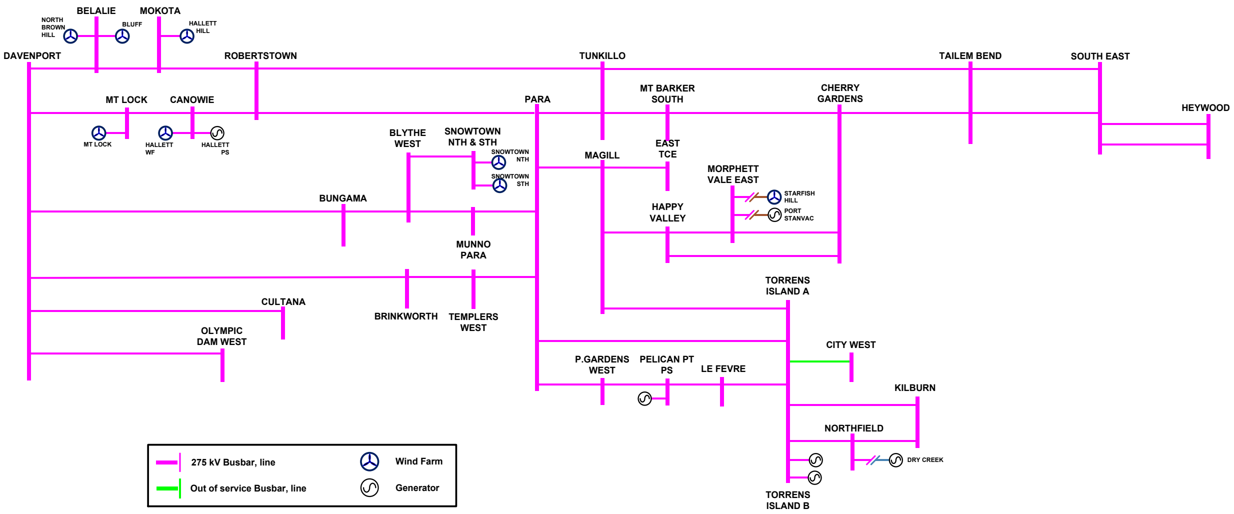
Specifically, AEMO will undertake the following:

- Repeat PSS/E and PSCAD studies documented in this report following:
  - Connection of any new non-synchronous generation.
  - Major SA system incidents, such as that on 3 March 2017.
- Investigate the impact of a higher number of on-line synchronous machines on:
  - Viability of the SA power system following loss of Heywood Interconnector.
  - Heywood Interconnector transient stability limit.
  - Effectiveness of post-separation load shedding.
- Investigate the impact on system strength as the ratio of non-synchronous/synchronous generation increases, including:
  - Determining the required number of on-line synchronous machines (including any synchronous condensers) during periods of low Interconnector transfer.
  - Determining the maximum level of non-synchronous generation as a function of the number of on-line synchronous machines which allows maintaining a secure operating state.
  - Determining the relative capability of various types of wind turbines with respect to their withstand capability as the number of on-line synchronous machines declines.
  - Identifying relays of potential susceptibility in consultation with ElectraNet.
- In consultation with TNSPs and Generators, develop requirements for expected performance of power swing blocking for transmission networks and out-of-step tripping for synchronous generators. Power swings are complex events, and dynamic interaction between the primary power system equipment and protective functions must be accurately accounted for. For this reason, correct distinction between stable and unstable swings can only be practically achieved by detailed power system modelling and simulation studies.

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 33 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, from Weatherzone.

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.

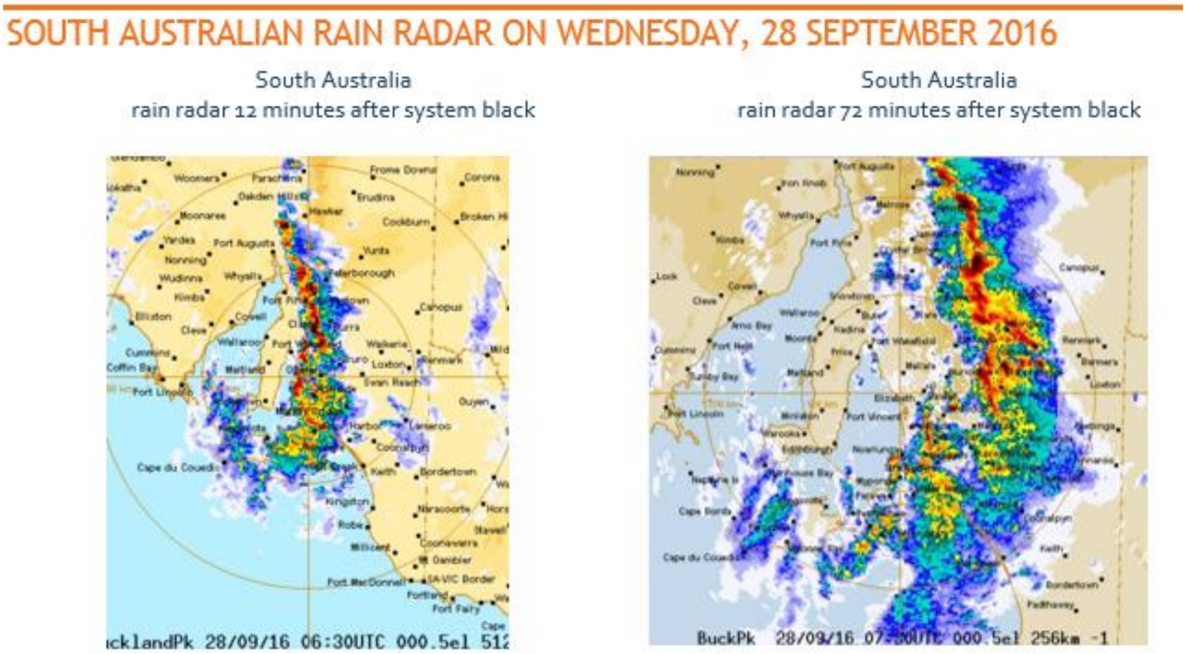
The major impact on Victoria and southern New South Wales has been rainfall leading localised to widespread flooding. This has largely been due to already saturated soils and heavily burdened rivers from above-average September rainfall.

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



The images above are from the Bureau of Meteorology.

On 14 November 2016, the Bureau of Meteorology published a report on the severe storm conditions in SA on 28 September 2016 entitled *Severe thunderstorm and tornado outbreak South Australia 28 September 2016.*[120]

The summary of this report stated:

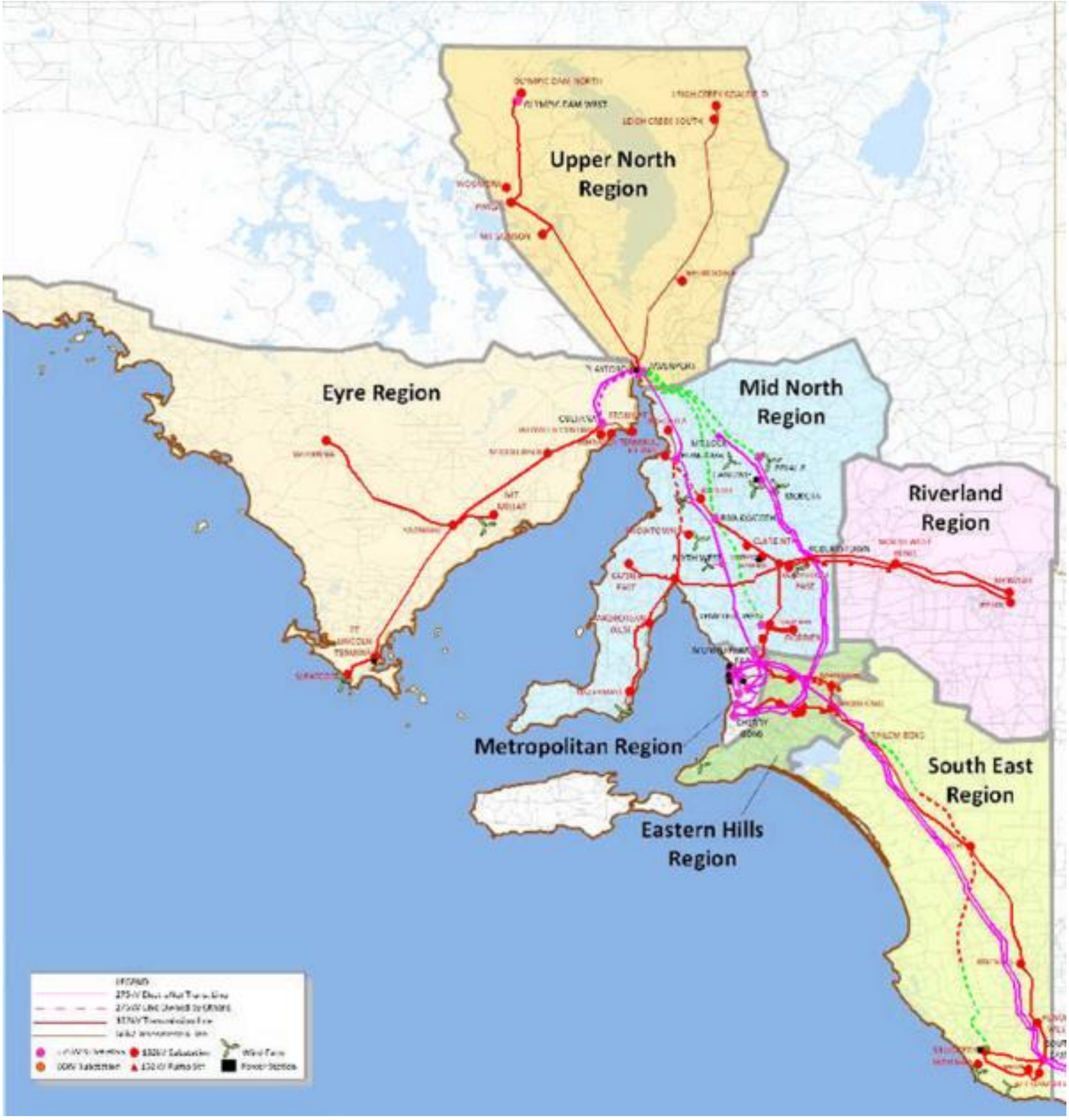
> *A severe thunderstorm and tornado outbreak impacted central and eastern districts of South Australia on 28 September 2016. Multiple supercell thunderstorms produced damaging to destructive winds, very large hailstones, locally intense rainfall and at least seven tornadoes.*

In Chapter 5, “Impact on the power transmission network”, the report noted:

> *Five faults led to the Black System Event, with four of these occurring on three transmission lines (Brinkworth–Templers West, Davenport–Belalie and Davenport–Mt Lock) (AEMO). A damage assessment on 6 October has identified that these faults were caused by the impact of supercell thunderstorms and tornadoes. Along with the faults reported by AEMO, it is likely that severe weather also led to damage on the Davenport–Brinkworth transmission line, shortly after the state-wide blackout had occurred.*

[120] Available at: http://www.bom.gov.au/announcements/sevwx/sa/Severe_Thunderstorm_and_Tornado_Outbreak_28_September_2016.pdf.

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 21 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[121]	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[122]	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

[121] For a further details of Severe Weather Warnings refer http://www.bom.gov.au/catalogue/warnings/WarningsInformation_SW_SWW.shtml
[122] For further details of Severe Thunderstorm Warnings refer http://www.bom.gov.au/catalogue/warnings/WarningsInformation_SW_STSW.shtml

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

Figure 35 Port Pirie weather observation (63km west of Belalie)

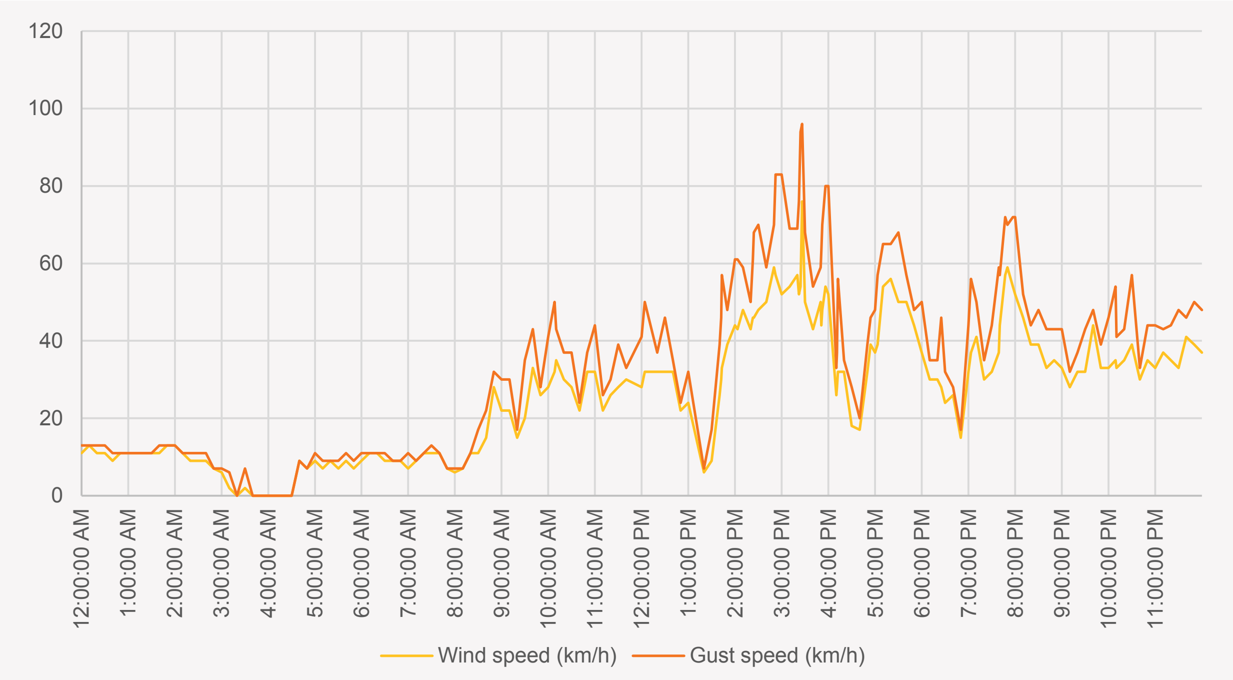


Figure 36 Port Augusta weather observation (16km west of Davenport)

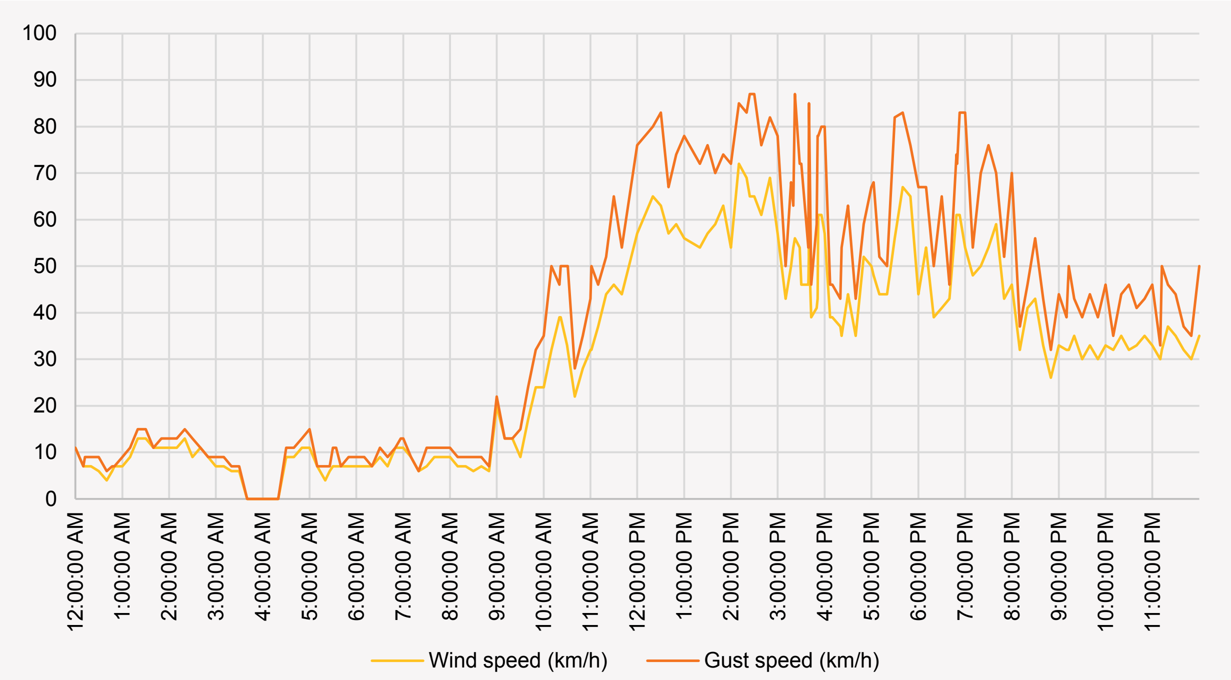
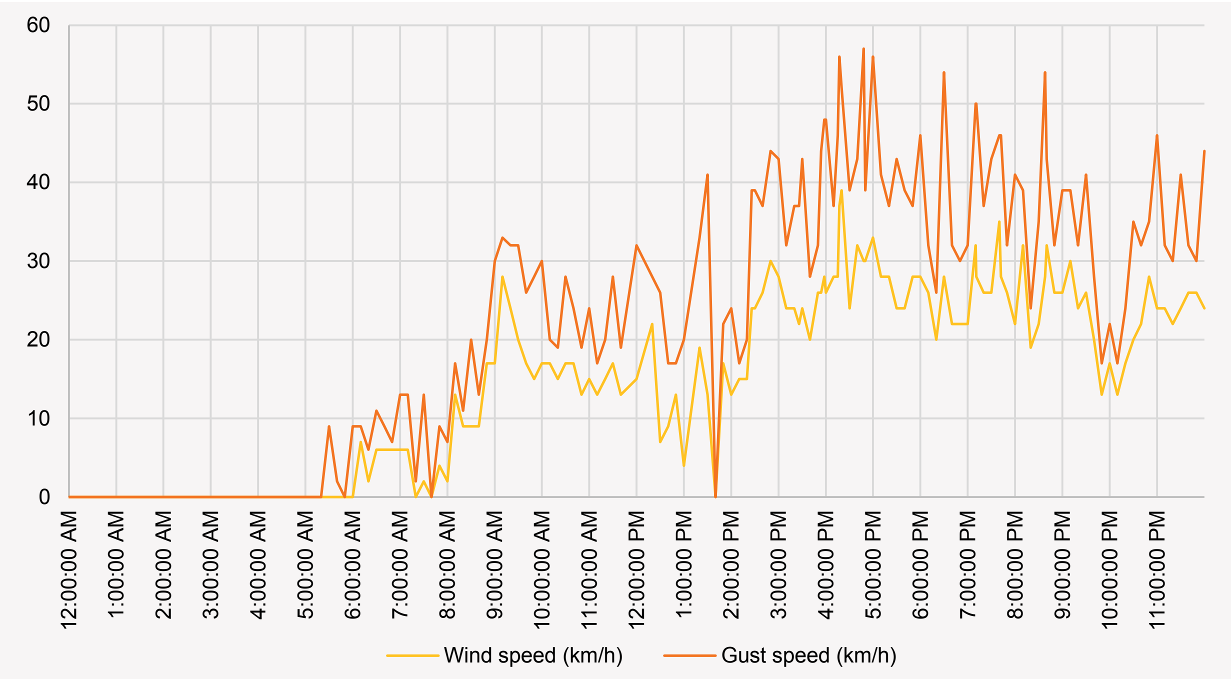
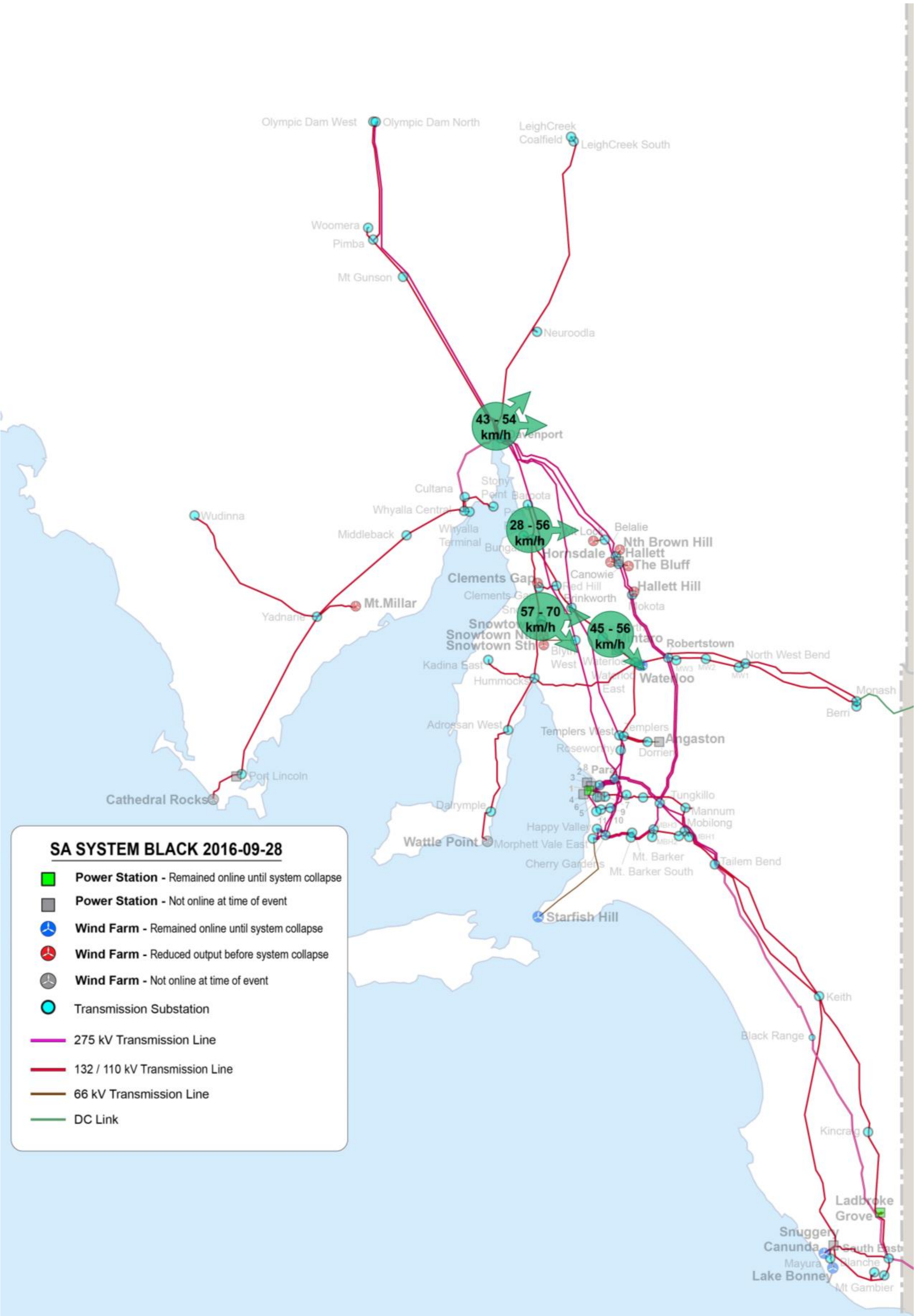


Figure 37 Clare weather observation (68km south of Belalie)



Information obtained from these four weather stations are collectively presented in Figure 38 for the 5-minute period immediately before the incident.

Figure 38 Wind speed data at representative weather stations several seconds before the Black System



E.3 Pre-event wind farm outputs

Table 22 details wind farms that reduced output during the pre-event timeframe.

Table 22 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 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.[123] 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.[124] 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 – 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.

[123] 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.

[124] 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 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 CBs 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'[125] 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.

[125] 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[126]

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[127] 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.[128] These classifications are reviewed every two years.[129] 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[130] 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

A 'black system' is defined in the NER (Chapter 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.

[126] Based on NER version 85, http://www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules.
[127] See http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Power-system-operation.
[128] 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.
[129] See Section 11.4.7 of AEMO's Power System Security Guidelines.
[130] In accordance with NER 4.8.1.

APPENDIX G. SA SYSTEM VOLTAGES

Figure 39 Voltages measured at Davenport–Olympic Dam 275 kV line

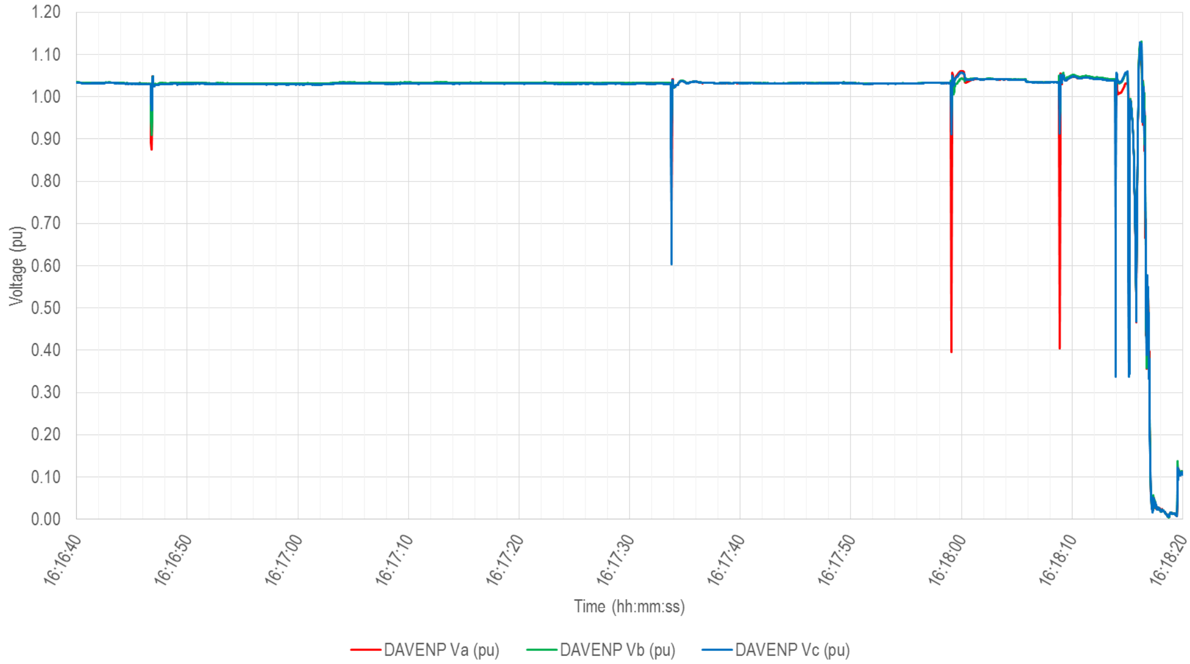


Figure 40 Voltages measured at Robertstown–Tungkillo 275 kV line

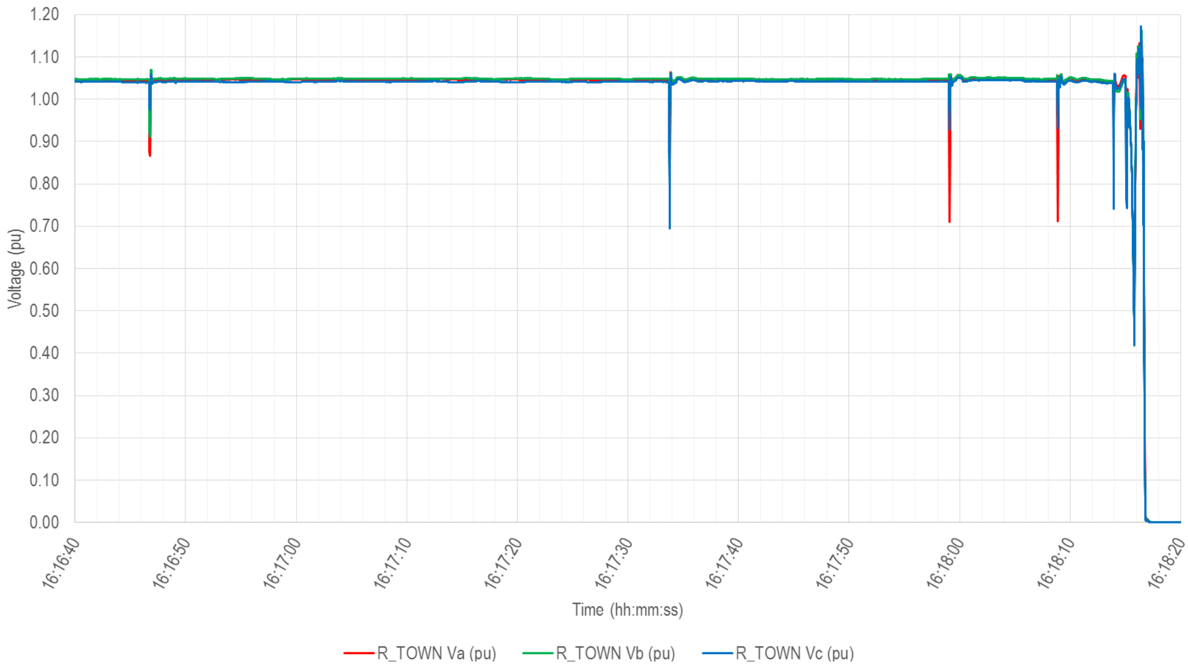


Figure 41 Voltages measured at Para–Parafield Gardens West 275 kV line

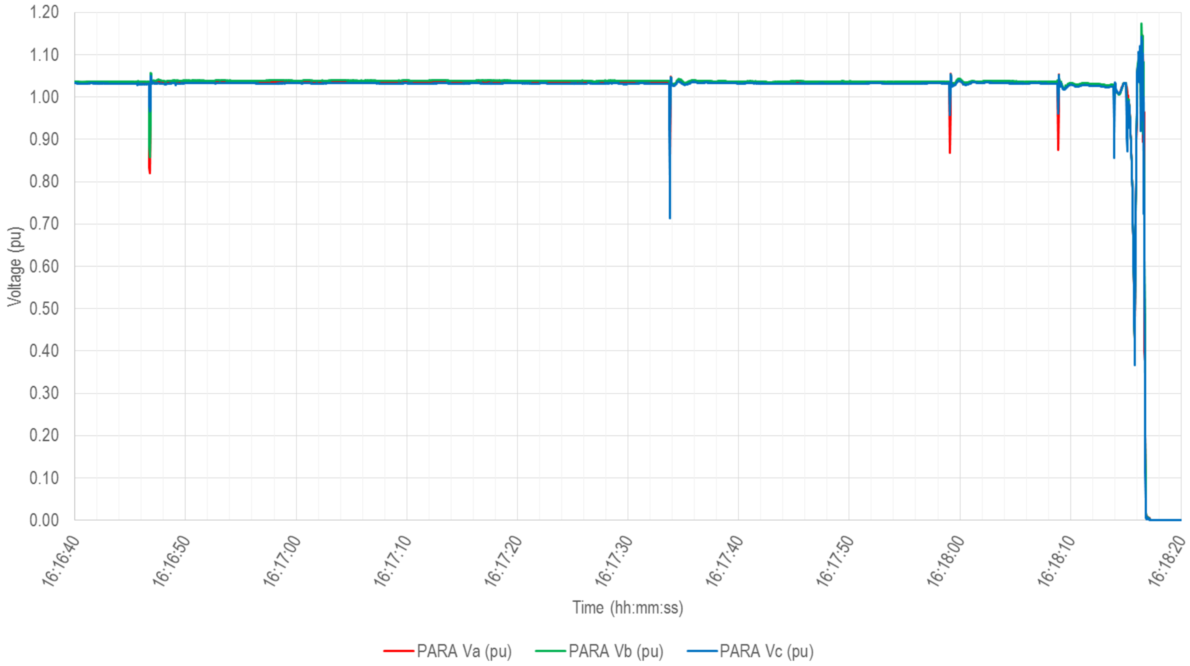
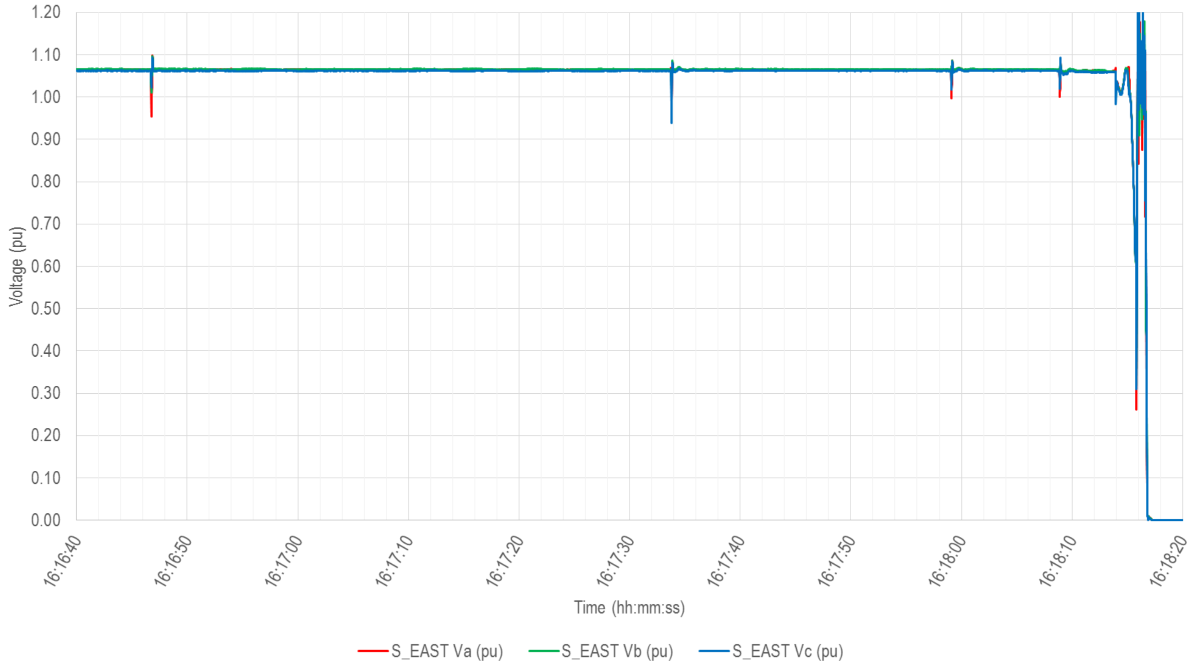


Figure 42 Voltages measured at South East–Tailem Bend No. 1 275 kV line



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 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[131] 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.

One of the 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.[132] 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.

[131] AEMO has an additional function in Victoria as the transmission network service provider (TNSP).
[132] Version 13 of the NER was effective on 31 May 2007.

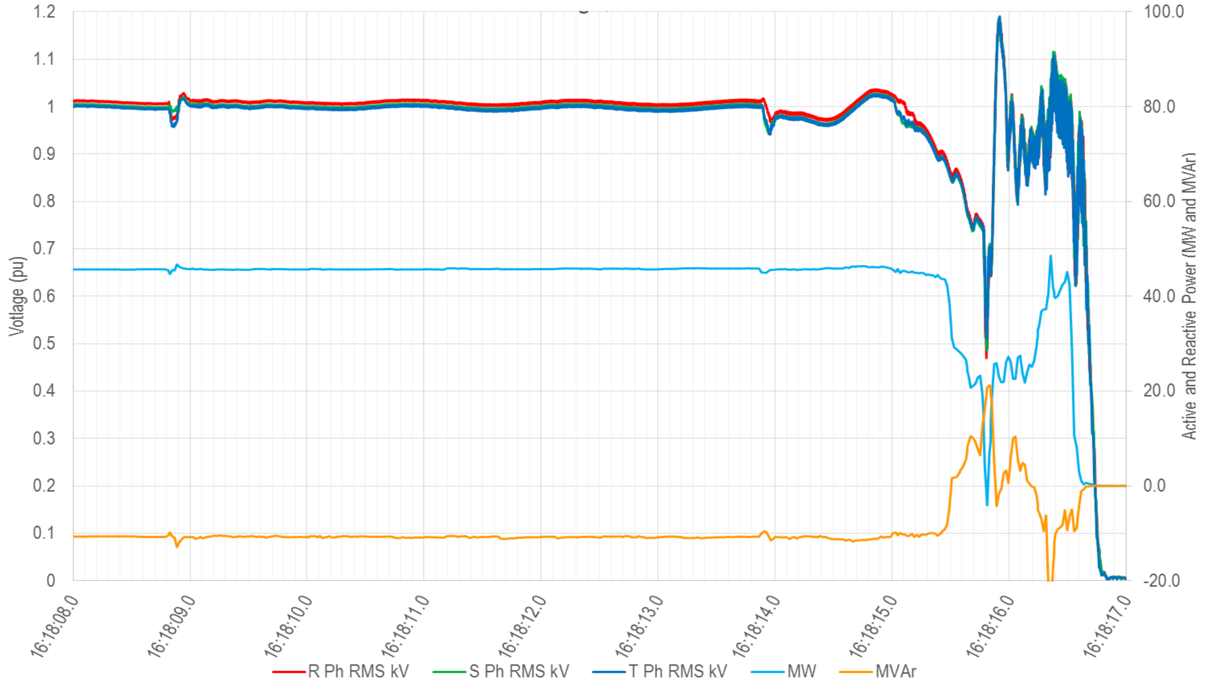
APPENDIX I. INDIVIDUAL GENERATOR RESPONSES

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

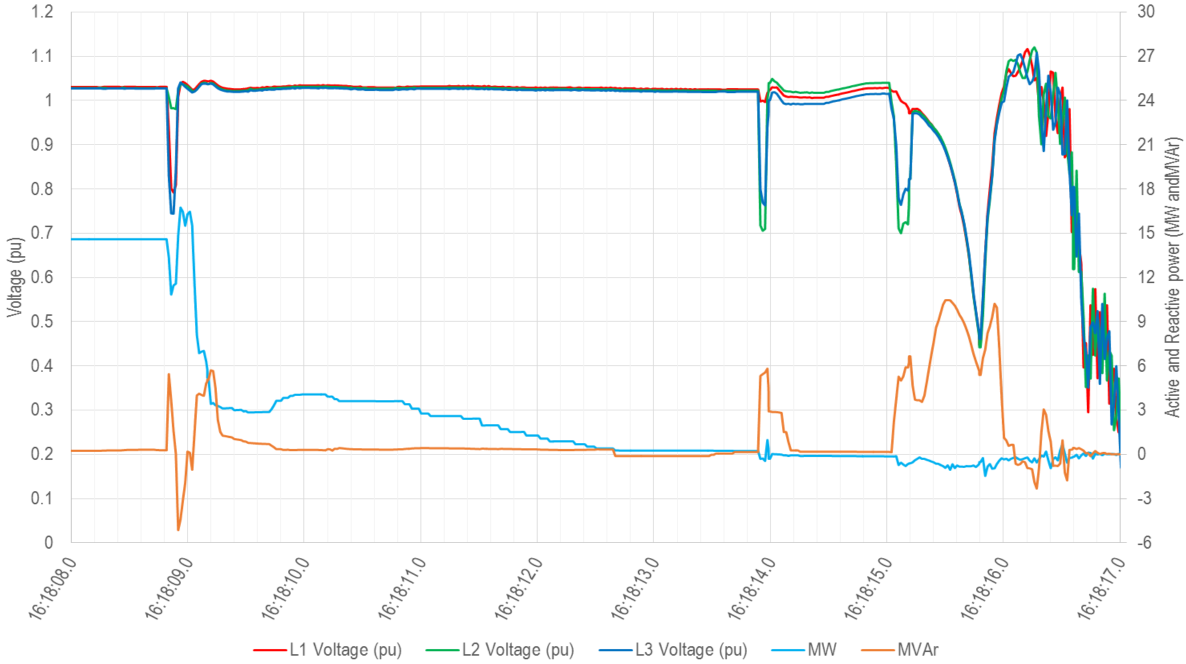
I.1.1 Canunda Wind Farm

Figure 43 Three-phase voltages, active and reactive power at Canunda Wind Farm's connection point



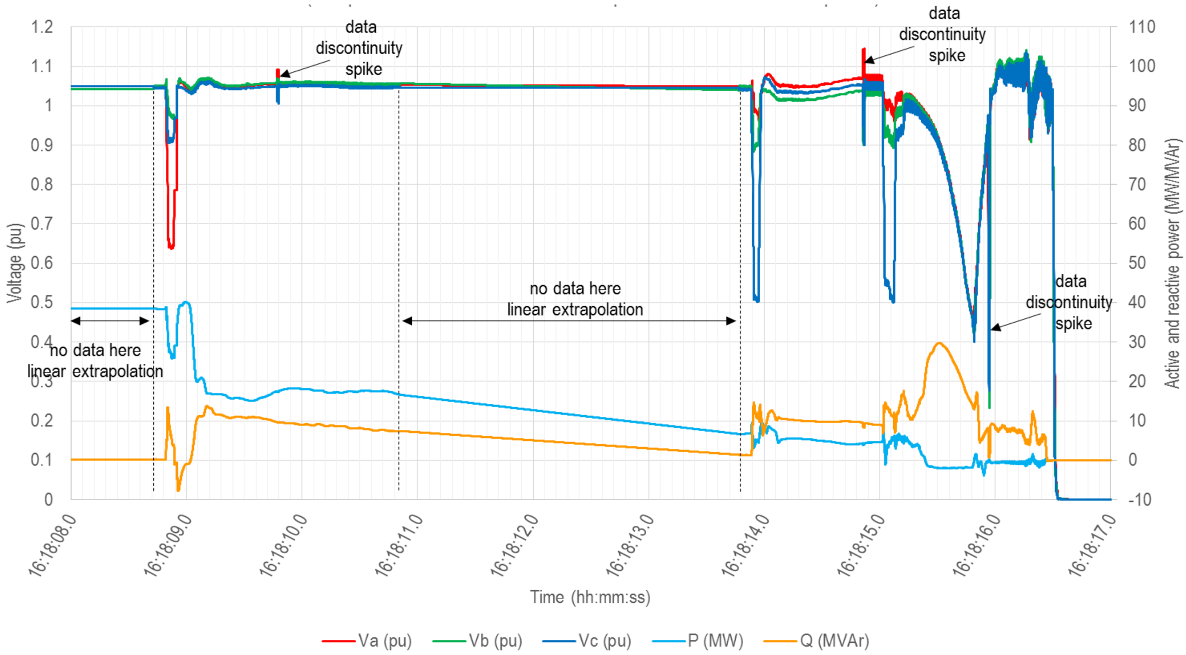
I.1.2 Clements Gap Wind Farm

Figure 44 Three-phase voltages, active and reactive power at Clements Gap Wind Farm's connection point



I.1.3 Hallett Wind Farm

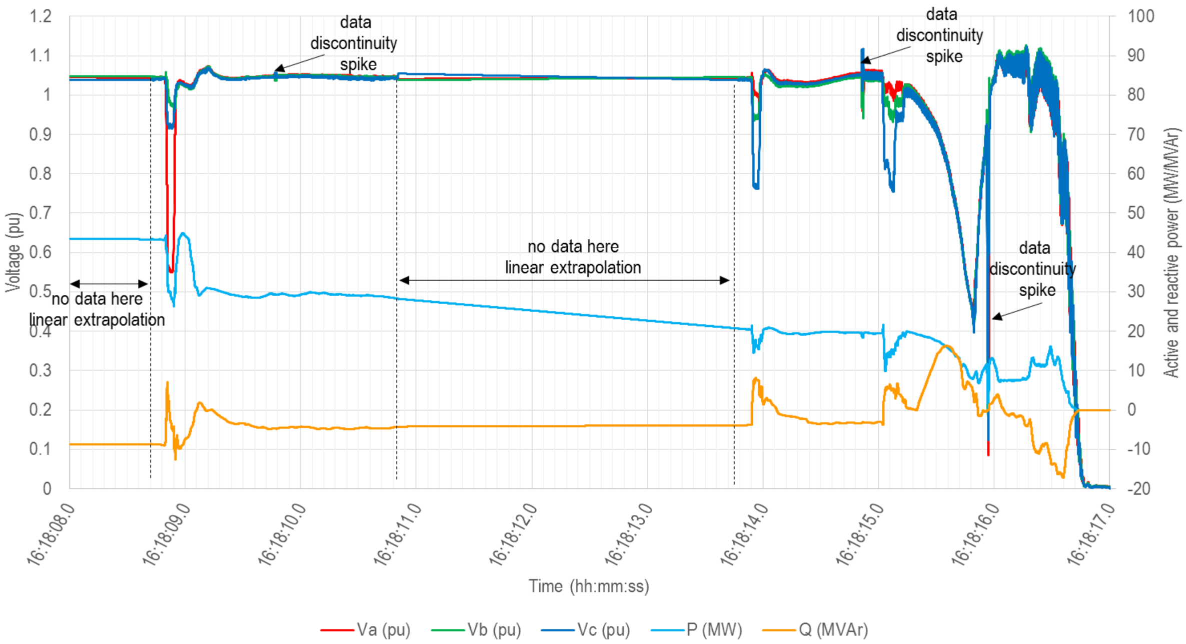
Figure 45 Three-phase voltages, active and reactive power at Hallett Wind Farm's connection point



Has periods of no data – linear extrapolation between points.

I.1.4 Hallett Hill Wind Farm

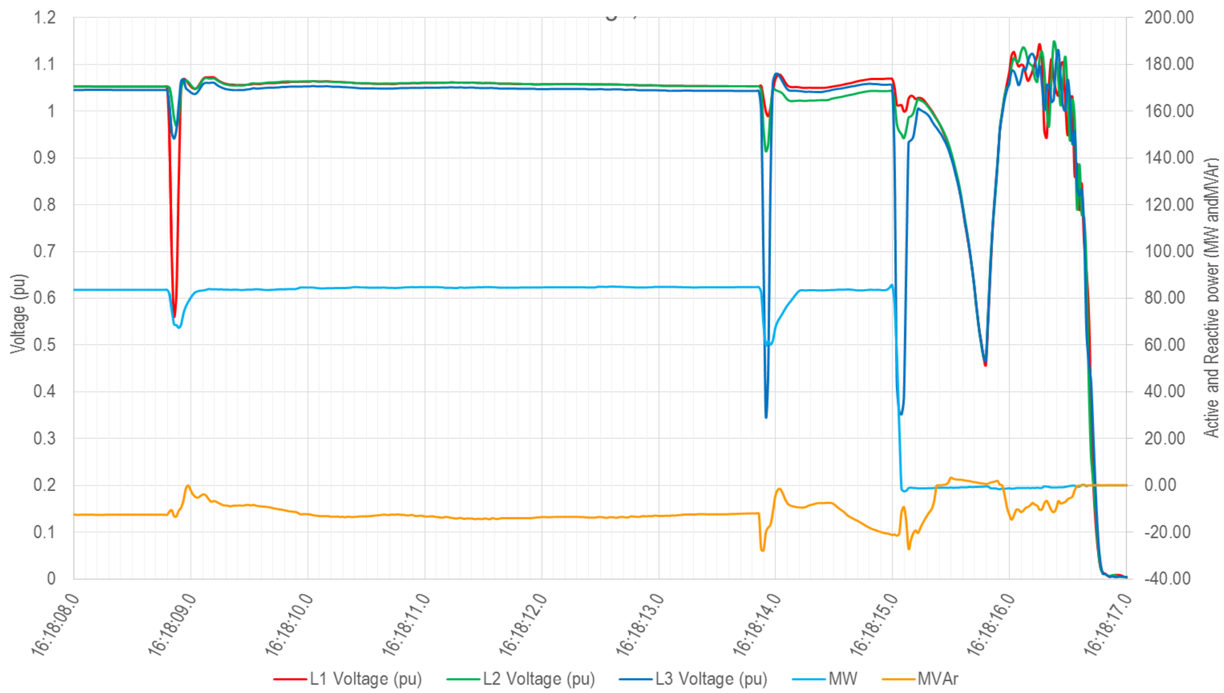
Figure 46 Three-phase voltages, active and reactive power at Hallett Hill Wind Farm's connection point



Has periods of no data – linear extrapolation between points.

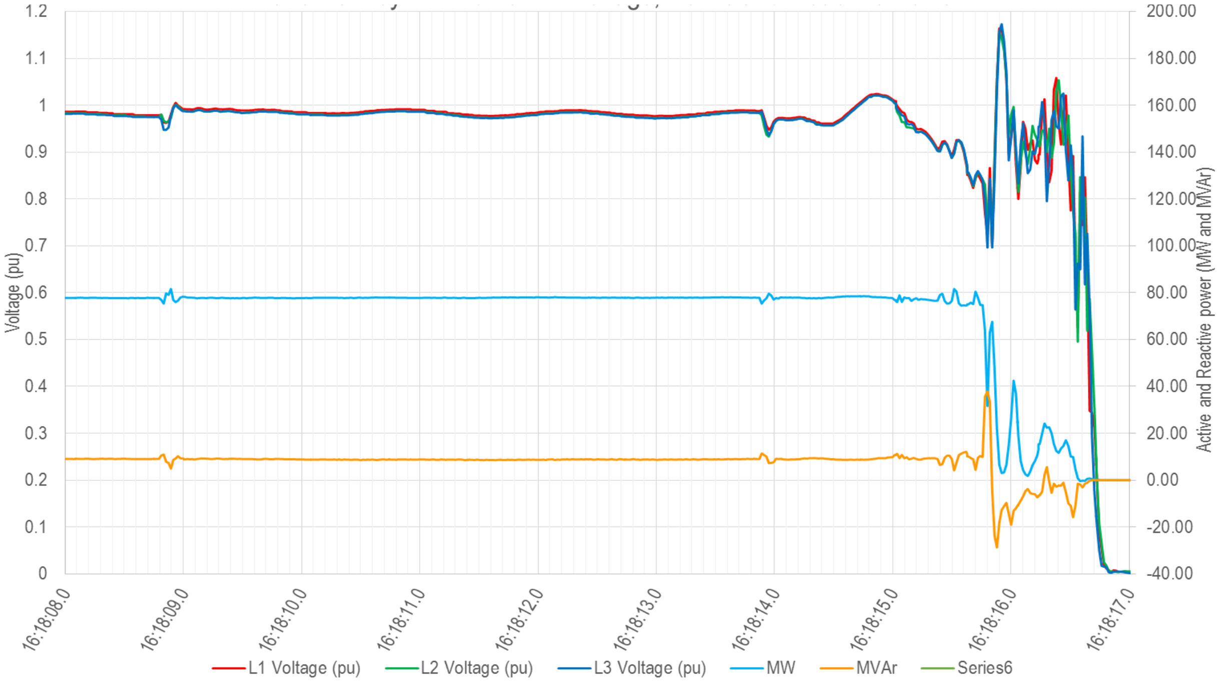
I.1.5 Hornsdale Wind Farm

Figure 47 Three-phase voltages, active and reactive power at Hornsdale Wind Farm's connection point



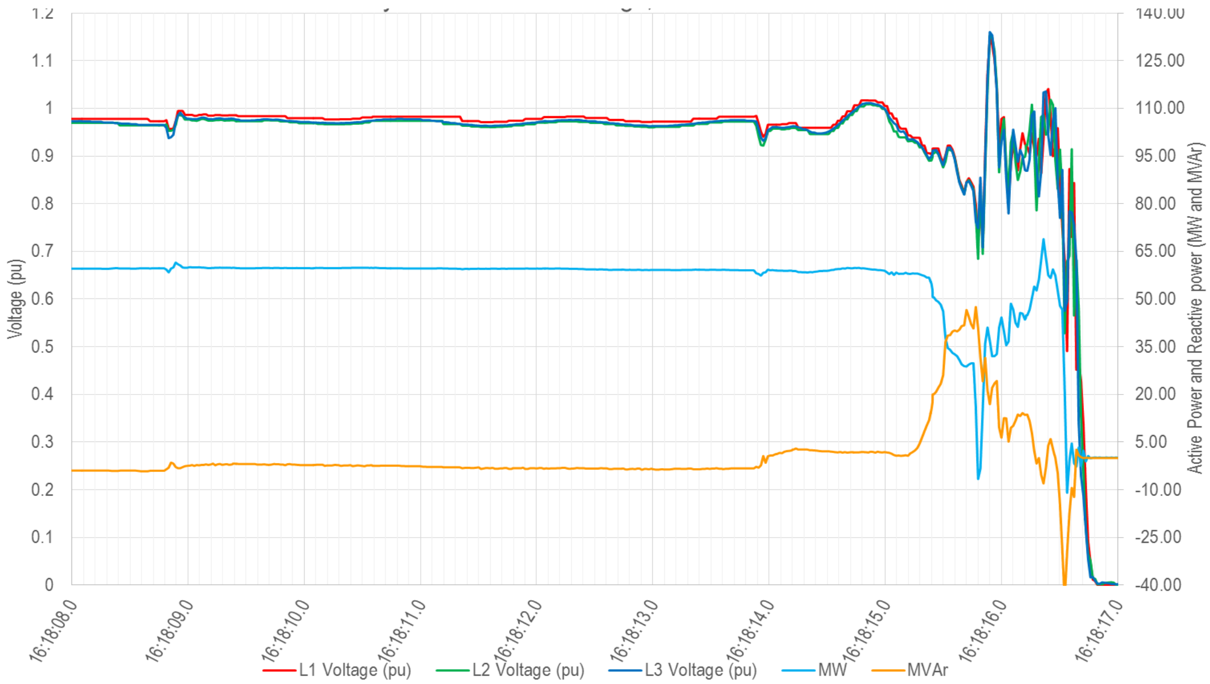
I.1.6 Lake Bonney 1 Wind Farm

Figure 48 Three-phase voltages, active and reactive power at Lake Bonney Wind Farm's connection point



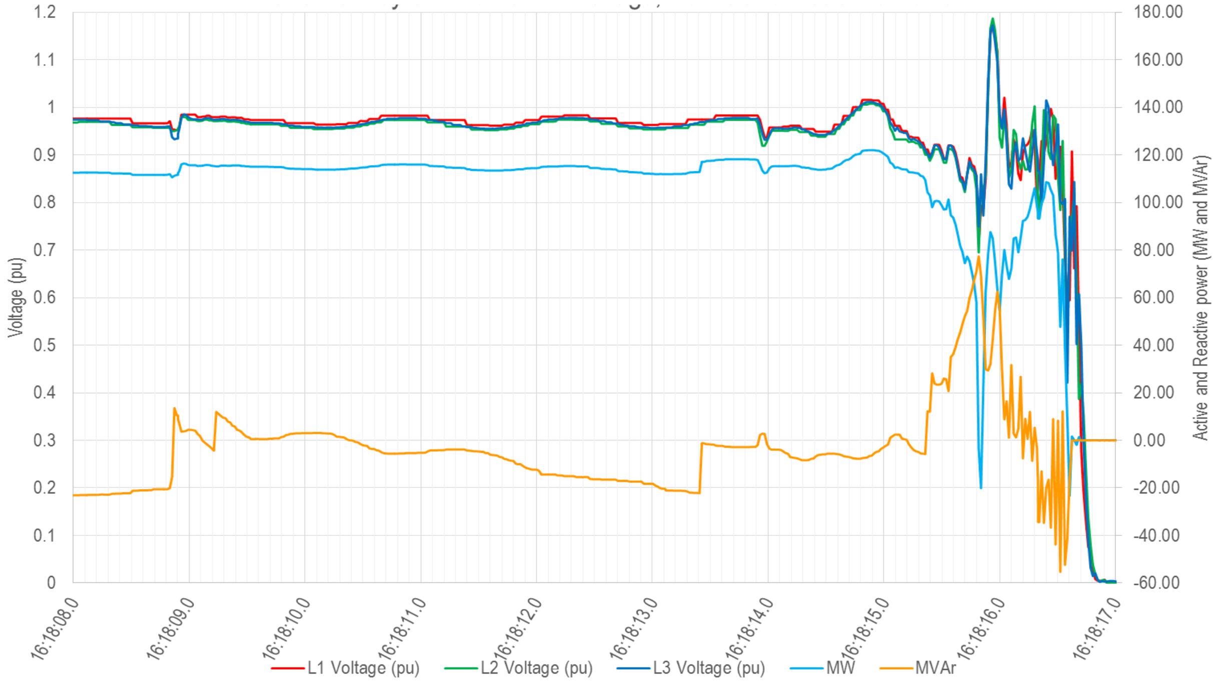
I.1.7 Lake Bonney 2 Wind Farm

Figure 49 Three-phase voltages, active and reactive power at Lake Bonney 2 Wind Farm's connection point



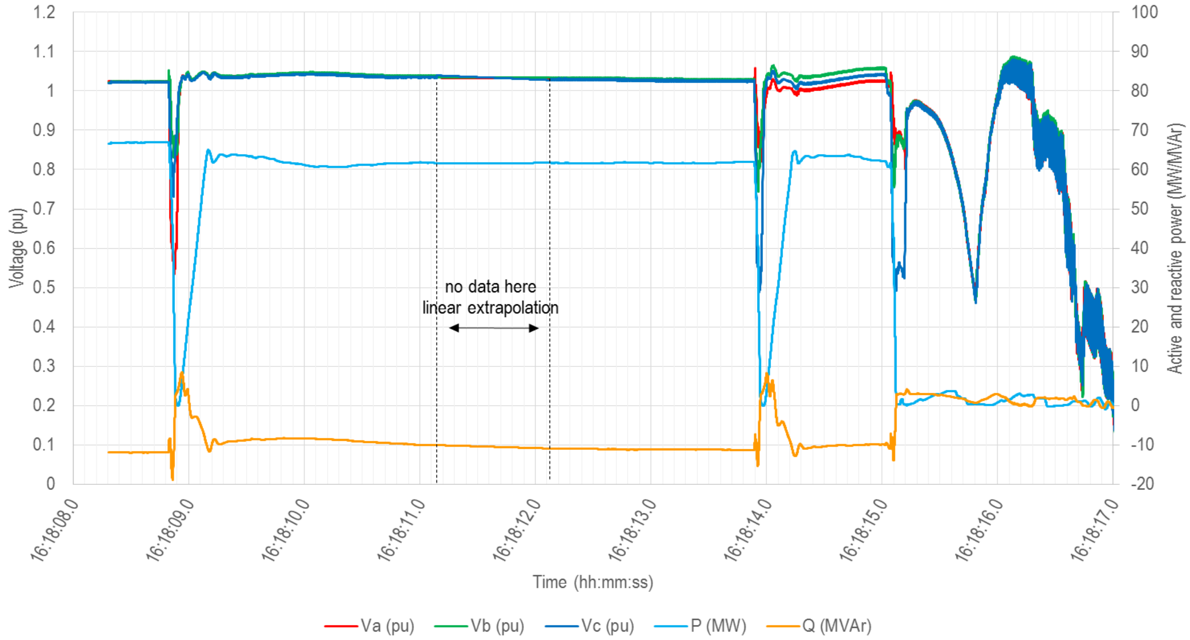
I.1.8 Lake Bonney 3 Wind Farm

Figure 50 Three-phase voltages, active and reactive power at Lake Bonney 3 Wind Farm's connection point



I.1.9 Mt Millar Wind Farm

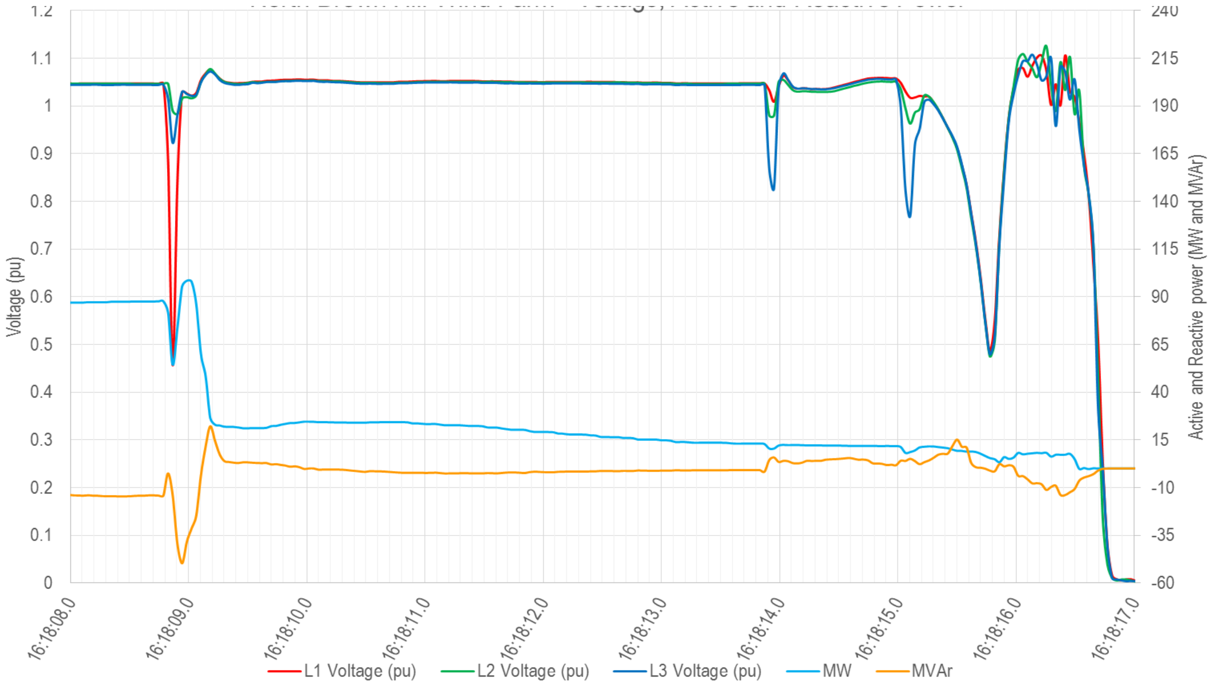
Figure 51 Three-phase voltages, active and reactive power at Mt Millar Wind Farm's connection point



Has periods of no data – linear extrapolation between points.

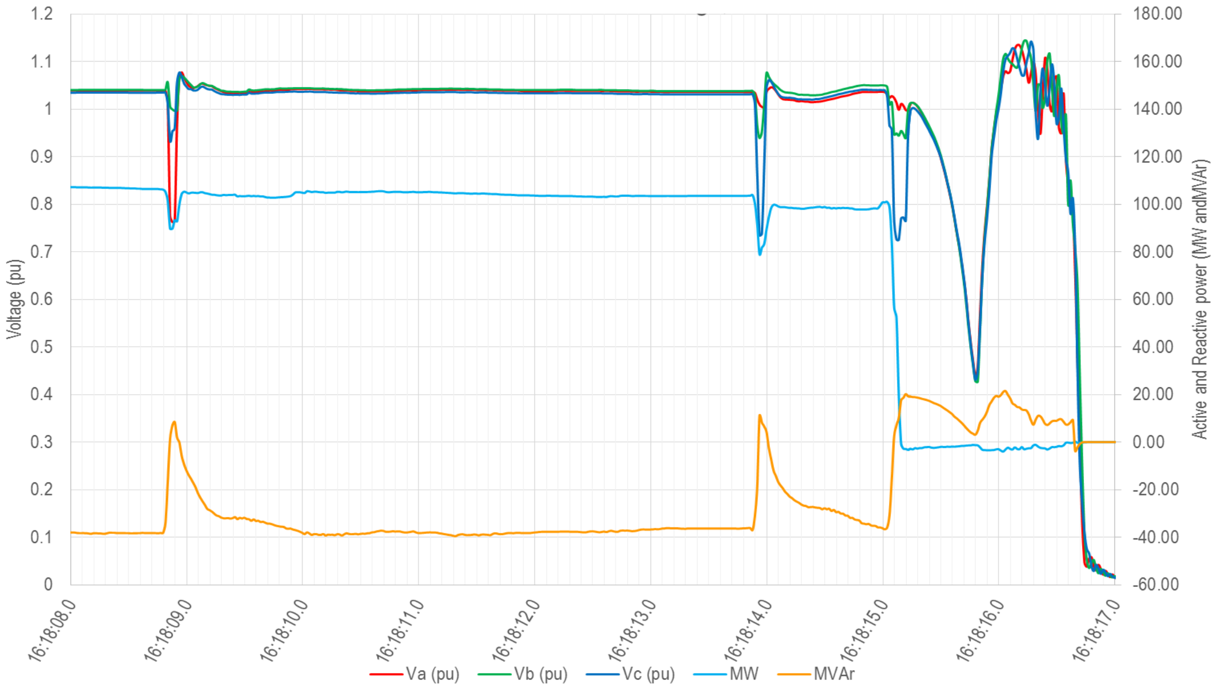
I.1.10 North Brown Hill Wind Farm

Figure 52 Three-phase voltages, active and reactive power at North Brown Hill Wind Farm's connection point



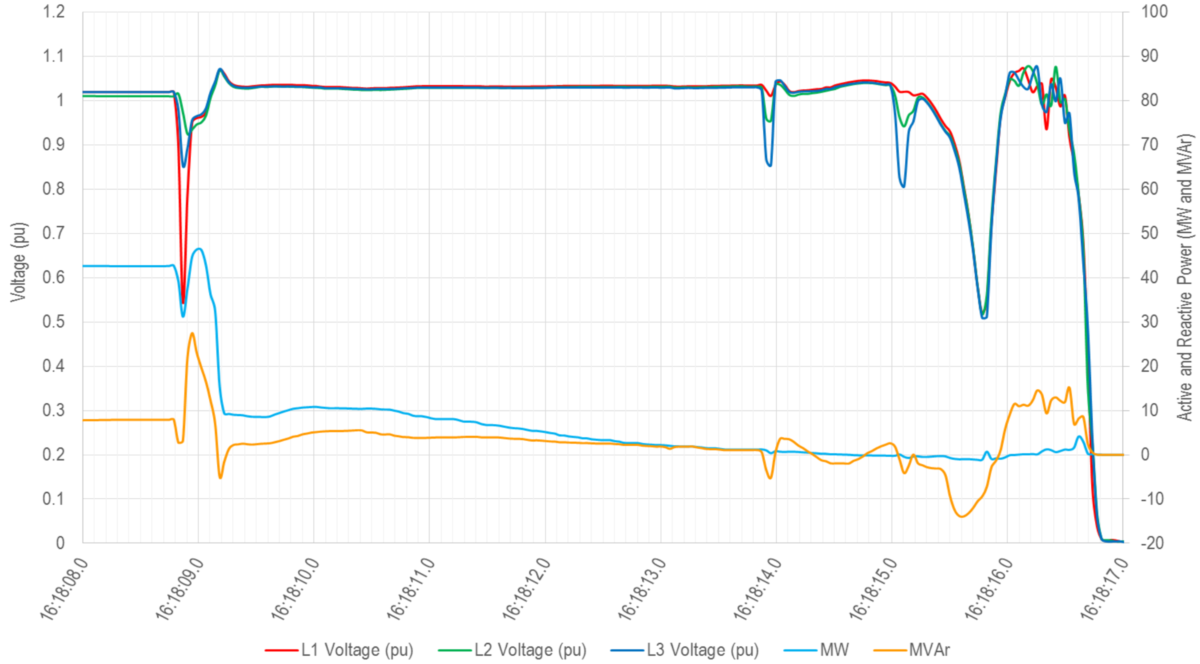
I.1.11 Snowtown 2 Wind Farm

Figure 53 Three-phase voltages, active and reactive power at Snowtown 2 Wind Farm's connection point



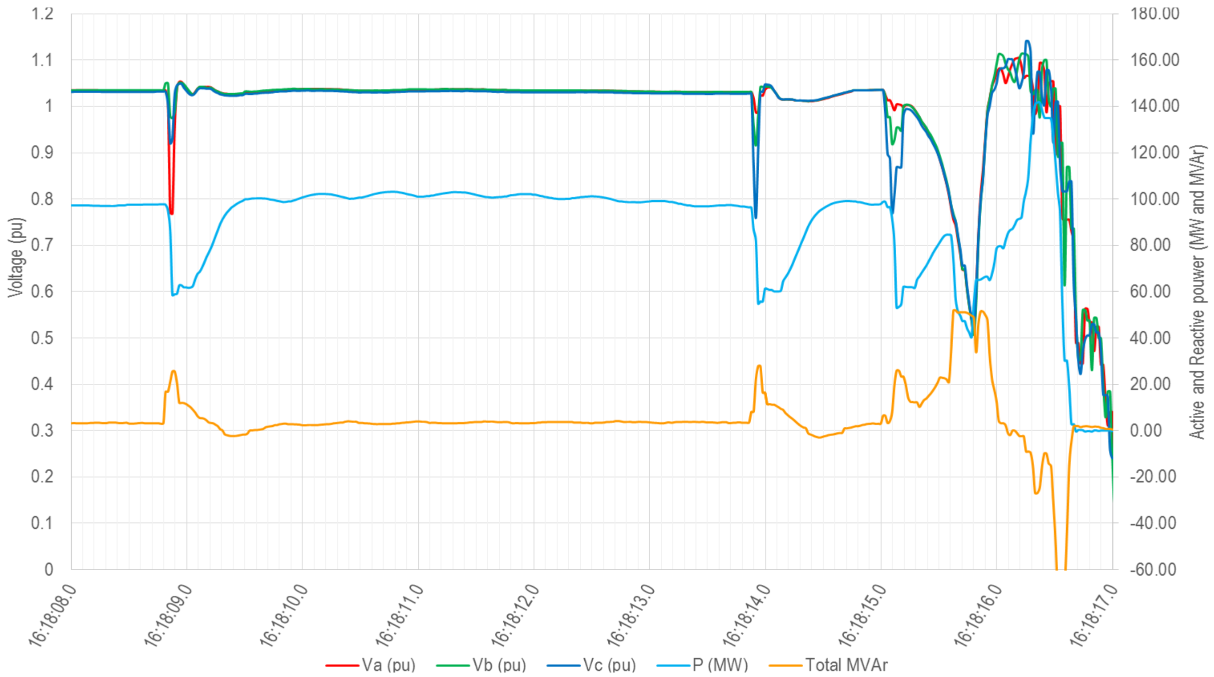
I.1.12 The Bluff Wind Farm

Figure 54 Three-phase voltages, active and reactive power at The Bluff Wind Farm's connection point



I.1.13 Waterloo Wind Farm

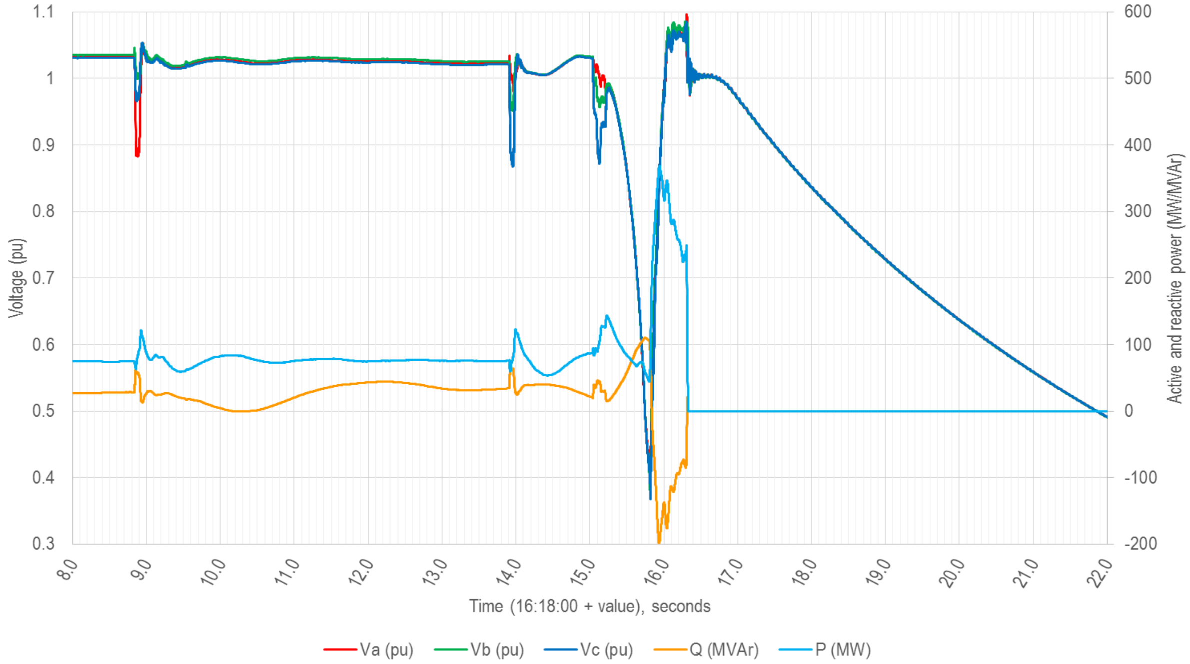
Figure 55 Three-phase voltages, active and reactive power at Waterloo Wind Farm's connection point



I.2 Individual synchronous generating unit's responses

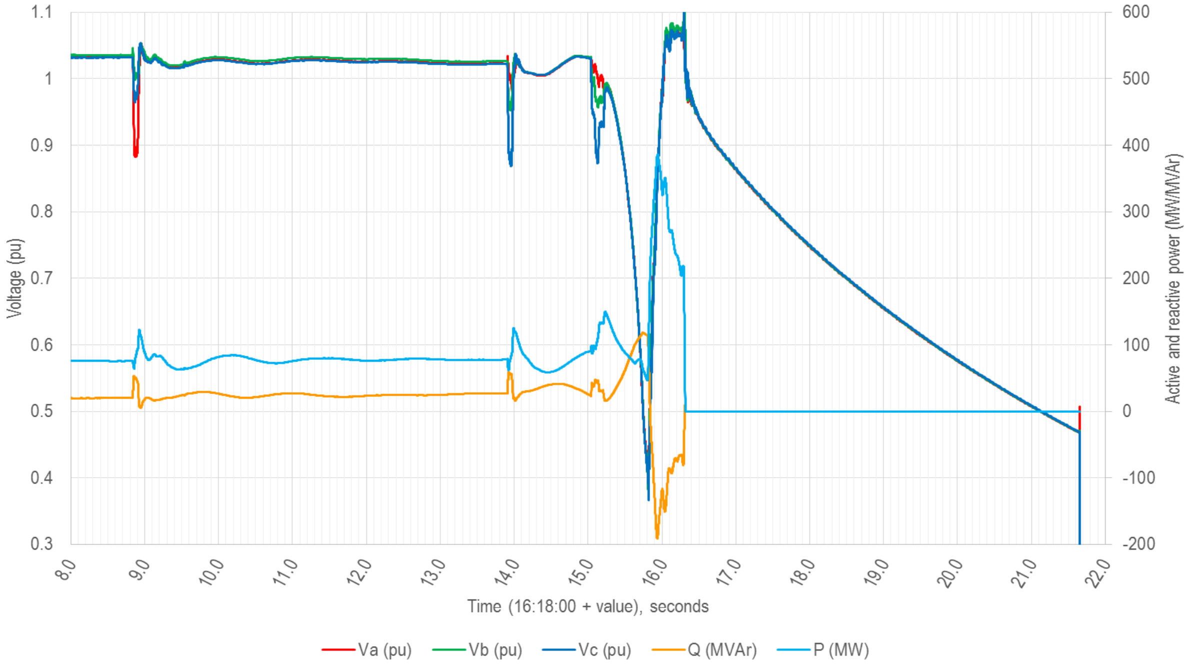
I.2.1 TIPS B1

Figure 56 Three-phase voltages, active and reactive power at TIPS B1 connection point



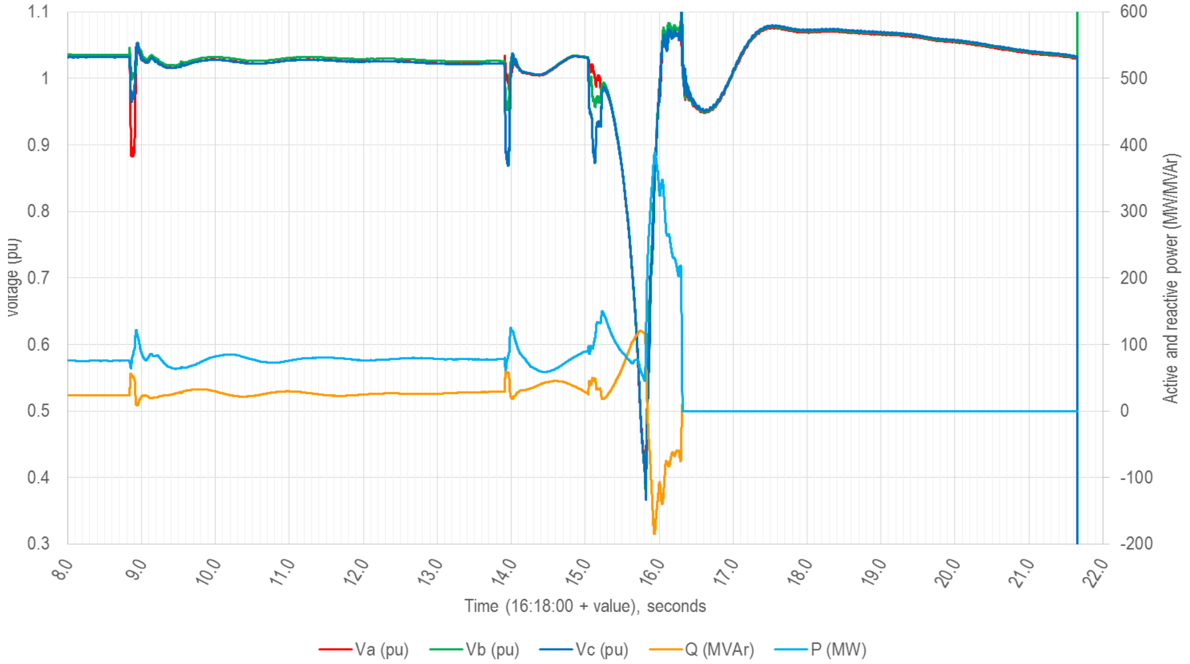
I.2.2 TIPS B3

Figure 57 Three-phase voltages, active and reactive power at TIPS B3 connection point



I.2.3 TIPS B4

Figure 58 Three-phase voltages, active and reactive power at TIPS B4 connection point



I.2.4 Ladbroke Grove units

Figure 59 Three-phase voltages active and reactive power at Ladbroke Grove's connection point

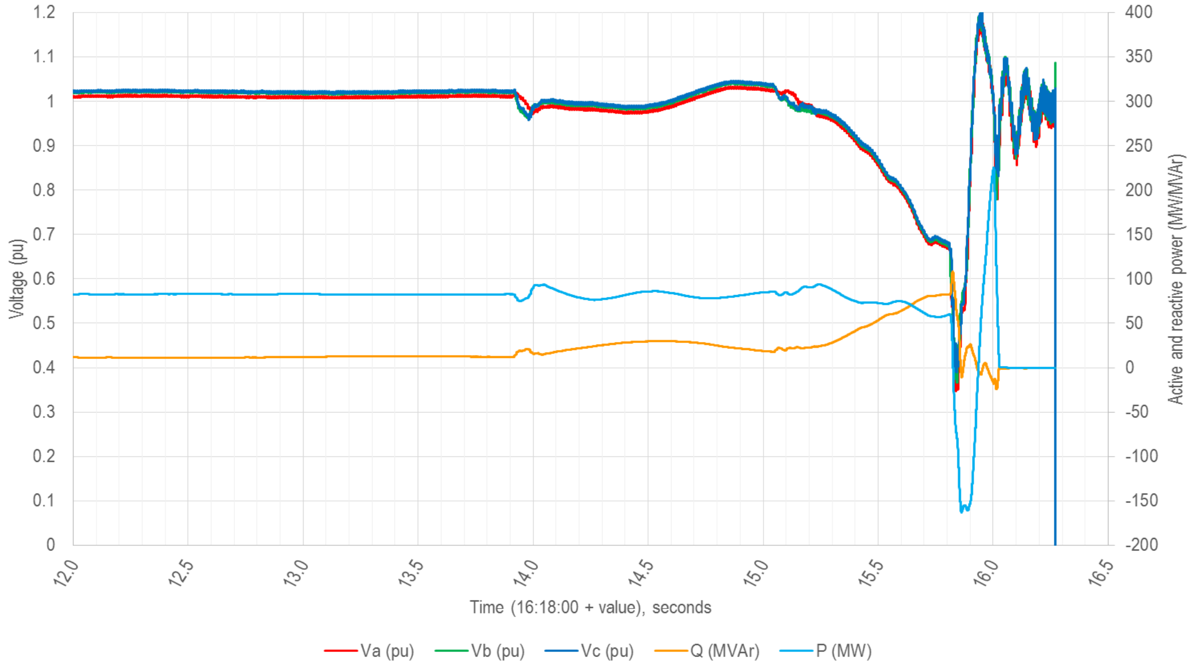
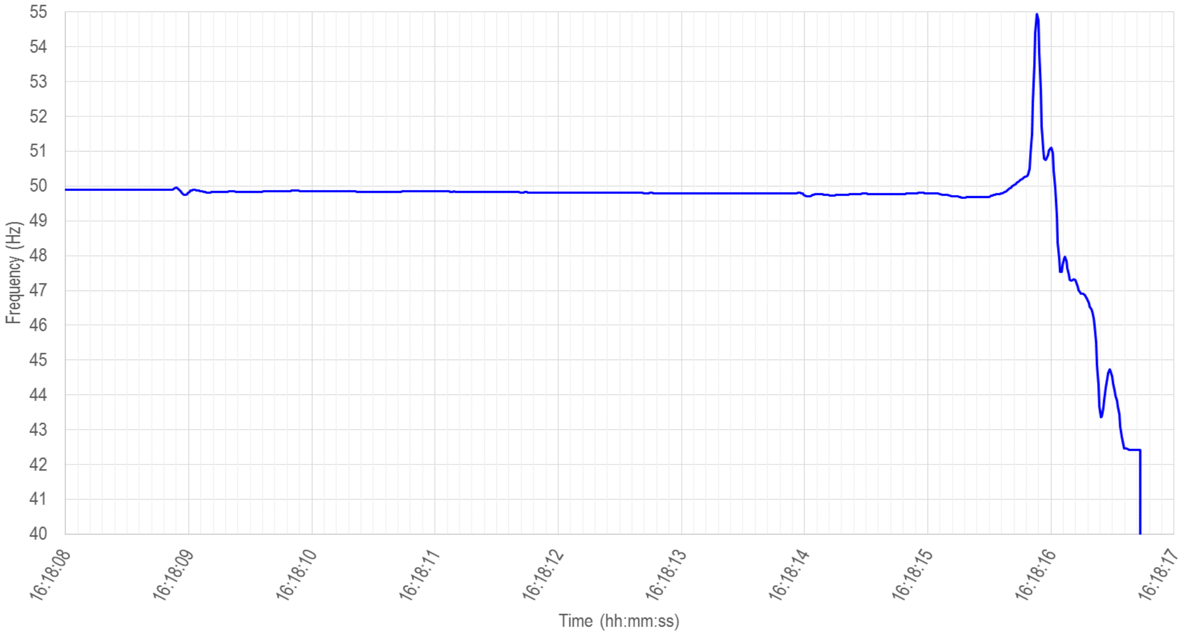


Figure 60 Measured frequency at Penola West to which Ladbroke Grove is connected



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.

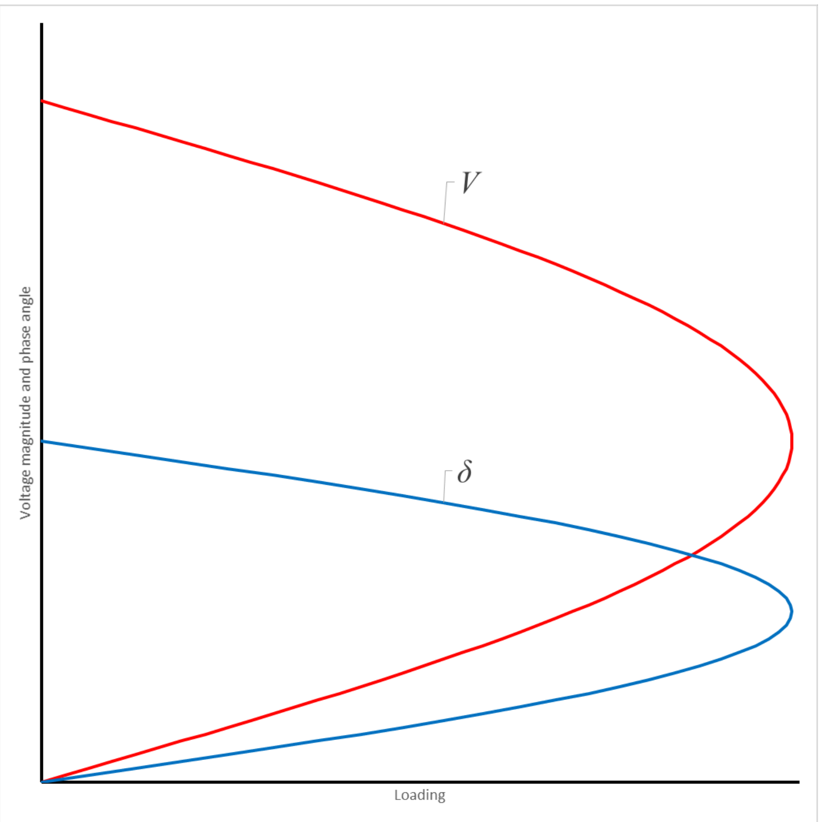
A saddle node bifurcation is the disappearance of a system equilibrium as parameters change slowly. The saddle node bifurcation of most interest to power systems occurs when a stable equilibrium at which the power system operates disappears. The consequence of loss of this equilibrium is that the system 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 61 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 61 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

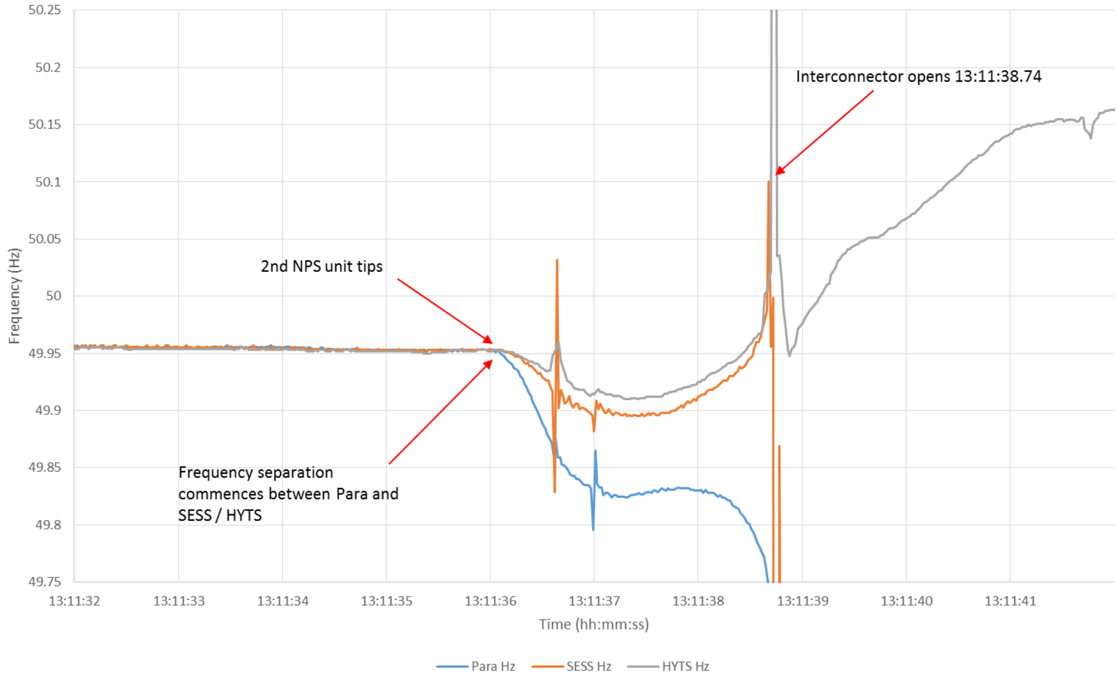
This appendix presents Heywood Interconnector MW flow and voltages across the SA power system for relevant system separation events following NEM inception.

K.1 2 December 1999

Figure 62 Heywood Interconnector MW flow, and SA system voltages for 2 December 1999 event

Figure 63 Heywood Interconnector MW flow, and SA system voltages for 2 December 1999 event (zoomed in)

Figure 64 SA and Heywood frequencies for 2 December 1999 event



K.2 8 March 2004

Figure 65 Heywood Interconnector MW flow, and SA system voltages for 8 March 2004 event

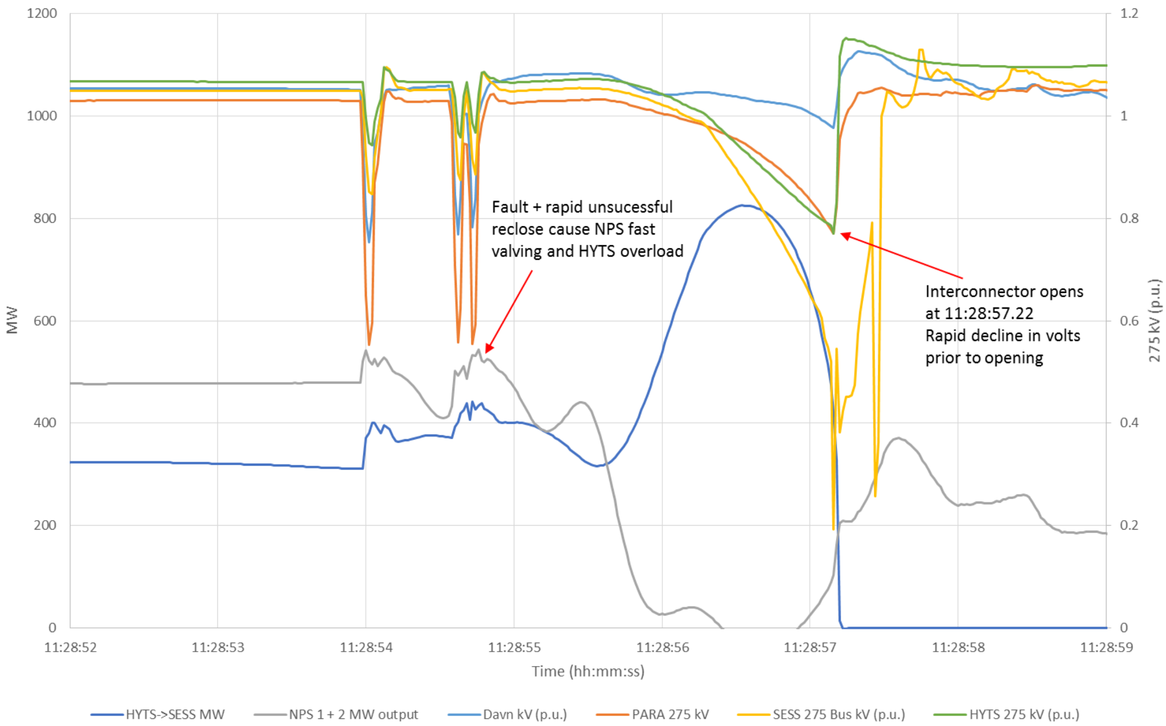
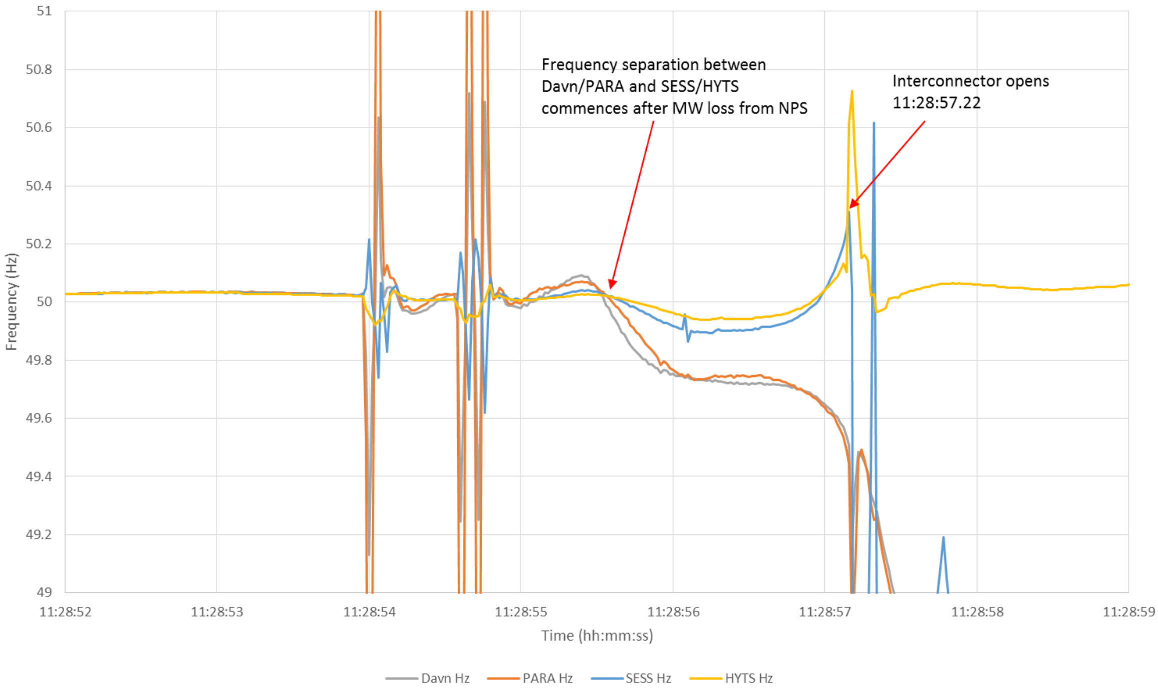


Figure 66 SA and Heywood frequencies for 8 March 2004 event



K.3 14 March 2005

Figure 67 Heywood Interconnector MW flow, and SA system voltages for 14 March 2005 event

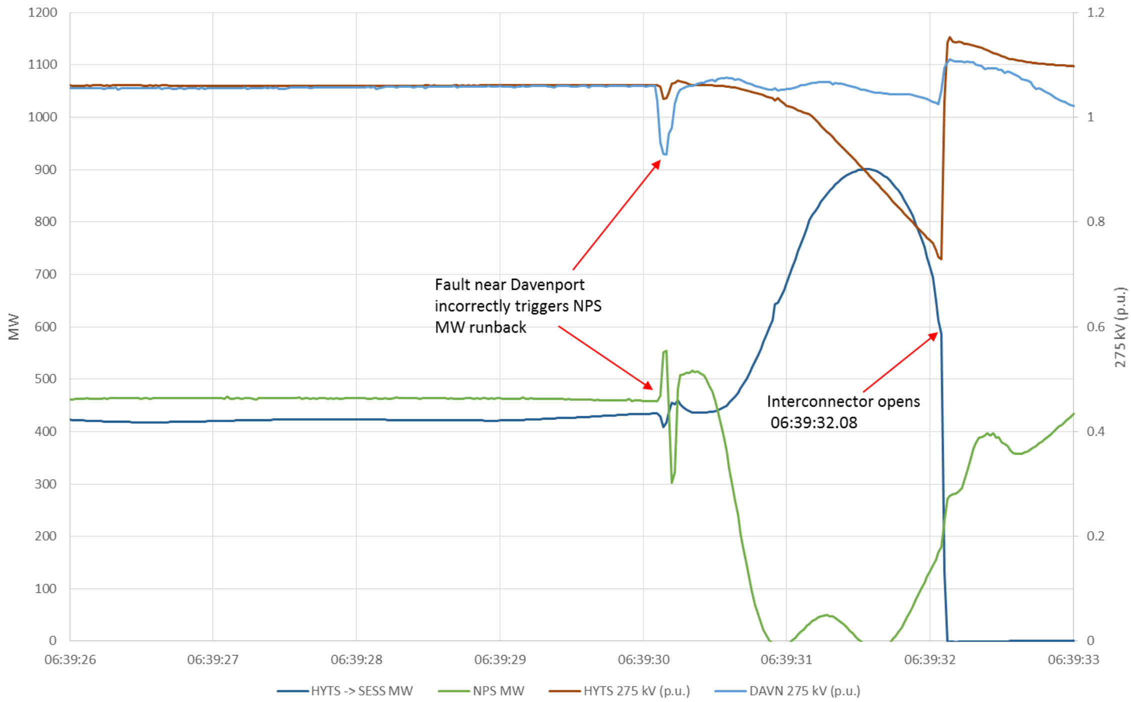
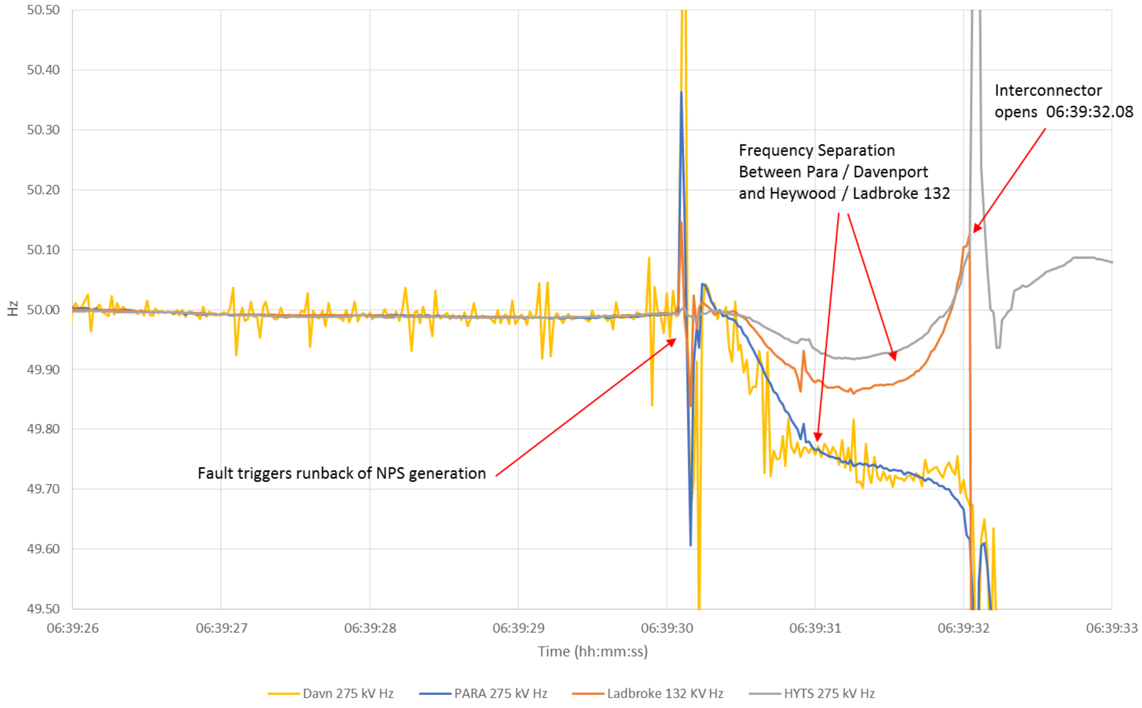


Figure 68 SA and Heywood frequencies for 14 March 2005 event



APPENDIX L. RESPONSE OF NETWORK REACTIVE SUPPORT PLANT

This appendix shows response of the two Para SVCs and series capacitors at Black Range (AEMO does not have sufficient data to determine the response of South East SVCs). Appendix L.3 has been added for this final report.

L.1 Dynamic reactive support plant

Figure 69 Three-phase voltages and MVAr injection by Para SVC1

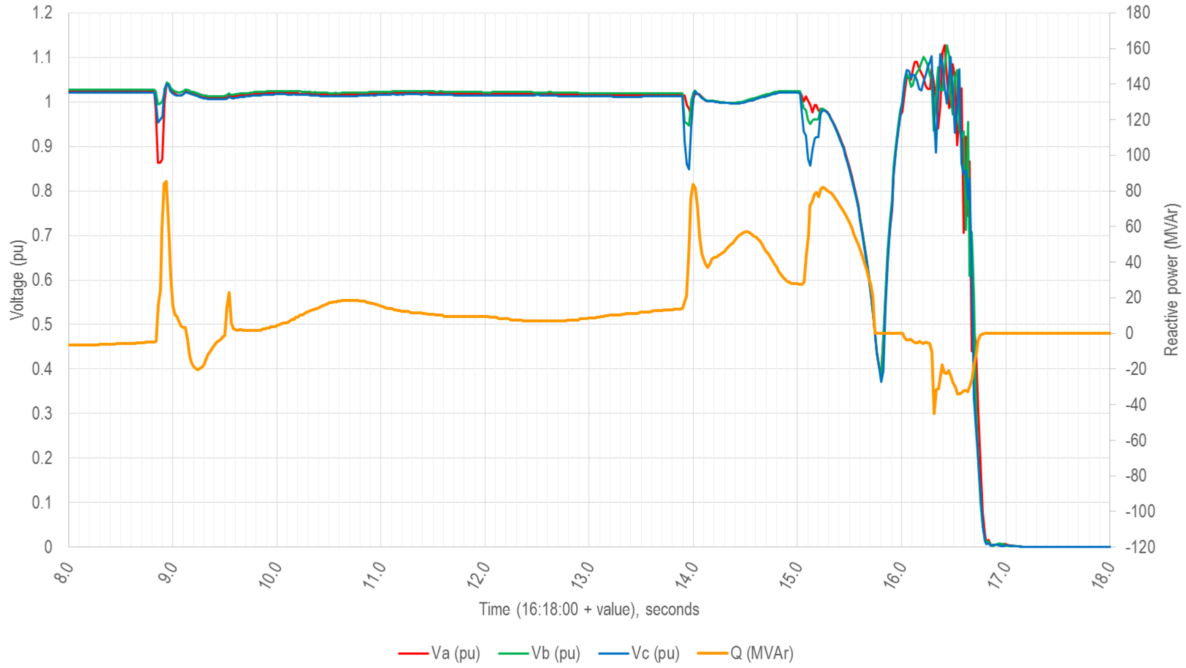
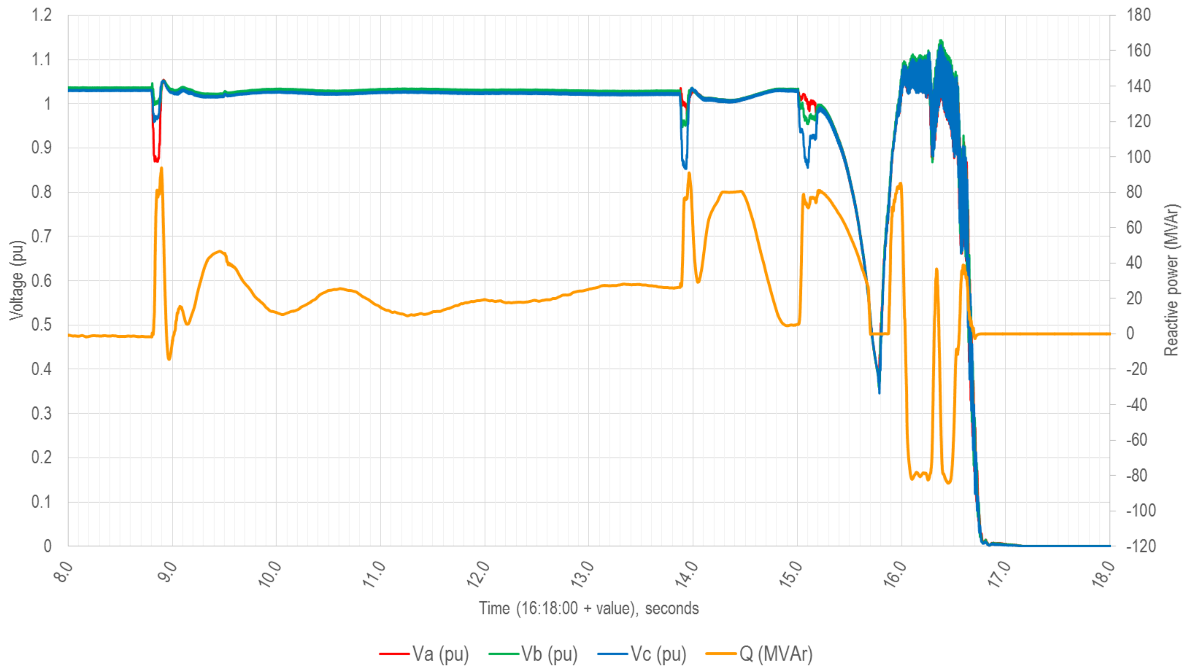
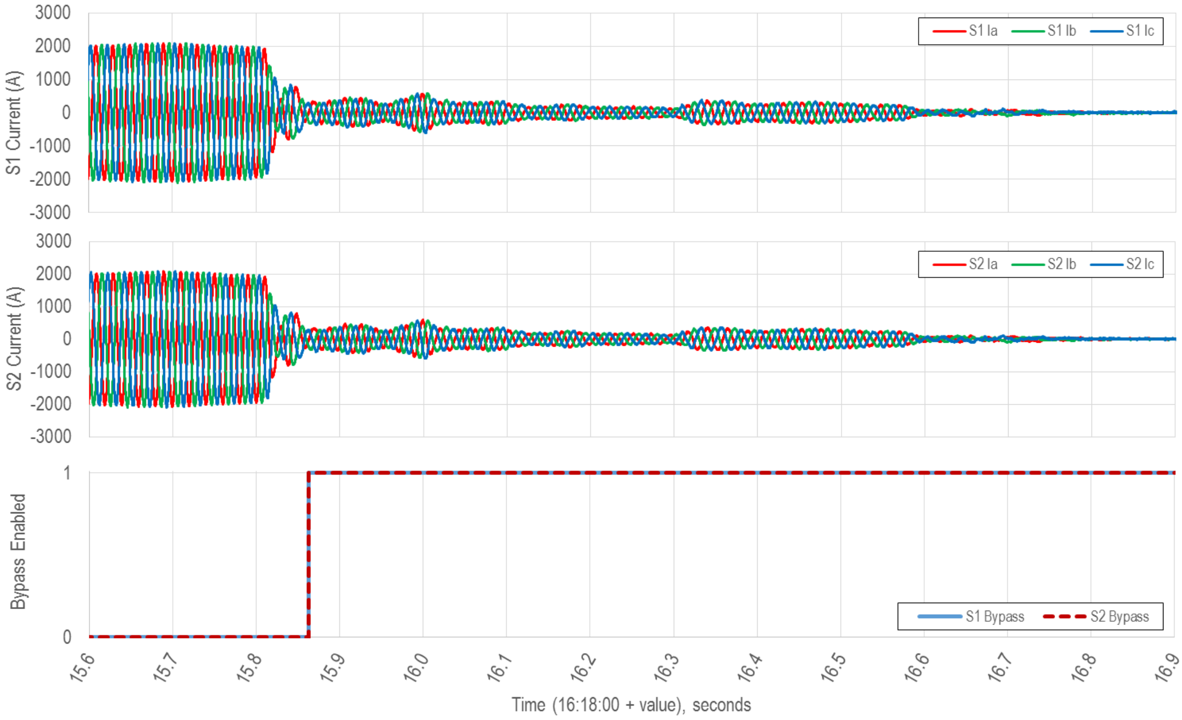


Figure 70 Three-phase voltages and MVAr injection by Para SVC2



L.2 Series capacitors

Figure 71 Current across the two series capacitors and bypass time



L.3 Assess improvements in the response of network dynamic reactive support plant

SVCs and the external capacitor/reactor banks they switch are employed to maintain dynamic voltage stability during system disturbances.

For most historical separation events in the SA power system, including the Black System, the SVCs at Para and South East Substations provided full capacitive reactive power in response to each of the network faults, including the one that occurred at 16:18:15:1 on 28 September 2016.

Due to full saturation of the SVCs' output at the respective capacitive reactive limit, they were unable to contribute further to avoid the rapidly declining system voltages caused by angular instability of the SA power system after the fault clearance.

AEMO, in consultation with ElectraNet, carried out a number of power system simulation studies to determine the extent to which the performance of the four SVCs can be optimised for events comprising multiple voltage disturbances and several hundred MW of generation reduction within the SA power system, like that which instigated angular instability on 28 September 2016.

The following modifications were investigated in the settings of the four SVCs:

- Faster switching of the 2x100 MVAr external capacitors at Para Substation, and the 1x100 MVAr capacitor at South East Substation.
  - At present, the pre-set time delay for switching in these capacitors is 5 seconds. Investigations were carried out to determine the extent to which faster switching of out-of-service capacitors with a time delay of 300 ms would assist in maintaining system voltages following significant generation reduction in SA.
- An increase in the slope (droop) of the SVC voltage control loop.

- A droop of 10% was investigated, compared to the current setting of 3%. This would make the SVC less responsive for shallower voltage disturbances, allowing the SVC to maintain some margin to respond to a subsequent voltage disturbance.

- A reduction in the SVC integral gain.
  - SVCs at both the Para and South East Substations utilise integral control, as opposed to proportional control. At present, the integral gains for the Para and South East SVC are set at 750 and 400 respectively. The impact of reducing the gains by half was investigated.

The following sub-sections evaluate the impact of these settings on the response of the SA power system through PSS/E power system simulation studies.

L.3.1 Para SVCs

Figure 72 to Figure 74 show the response of the two Para SVCs during the actual event, and compare these to modelled responses obtained with the above three modifications implemented.

These studies indicate that the response of the Para SVCs did not play a part in the causation chain resulting in system separation, and that none of the modelled three improvements would have prevented system separation. This can be attributed to the fact that the SVCs can only address the symptom (dynamic voltage decline) rather than the cause (angular instability).

Figure 72 Reactive power output from the SVCs and external capacitors

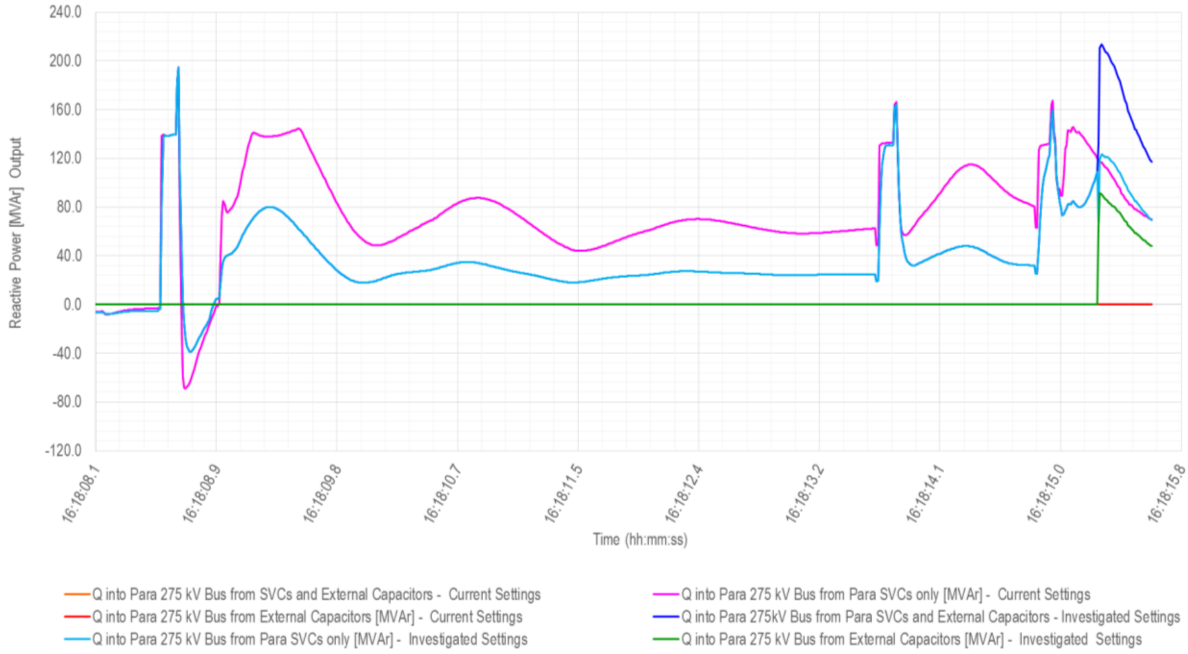


Figure 73 System voltages

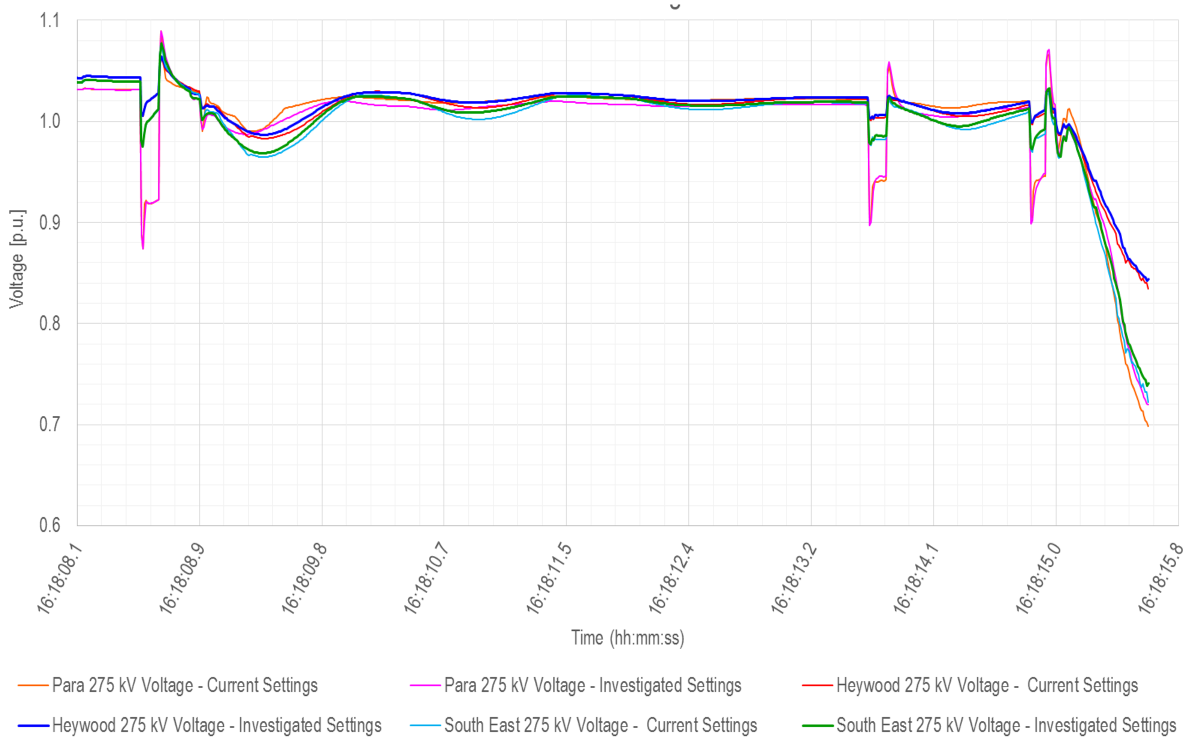
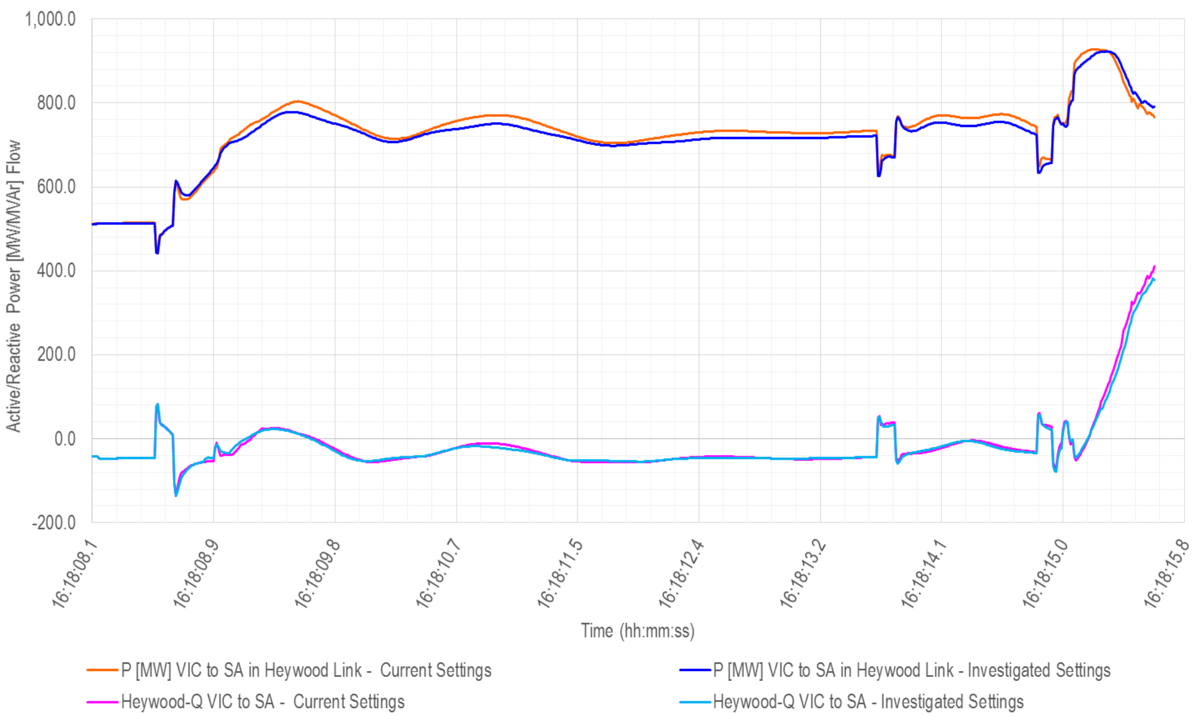


Figure 74 Active and reactive power transfer at Heywood Interconnector



L.3.2 South East SVCs

Figure 75 to Figure 77 depict responses of the South East SVCs for the operating conditions during the Black System with the current SVC settings, and with the modified setting investigated.

Due to the close proximity to the Heywood Interconnector, improvements in the response of the South East SVCs would have marginally higher impact on Heywood Interconnector's transfer capability than that achieved by improved response of Para SVCs.

However, power system simulation studies demonstrate that these SVCs cannot prevent system separation, or provide a tangible contribution to system stability for events caused by major loss of generation within the SA power system.

Figure 75 Reactive power output from the SVCs and external capacitor

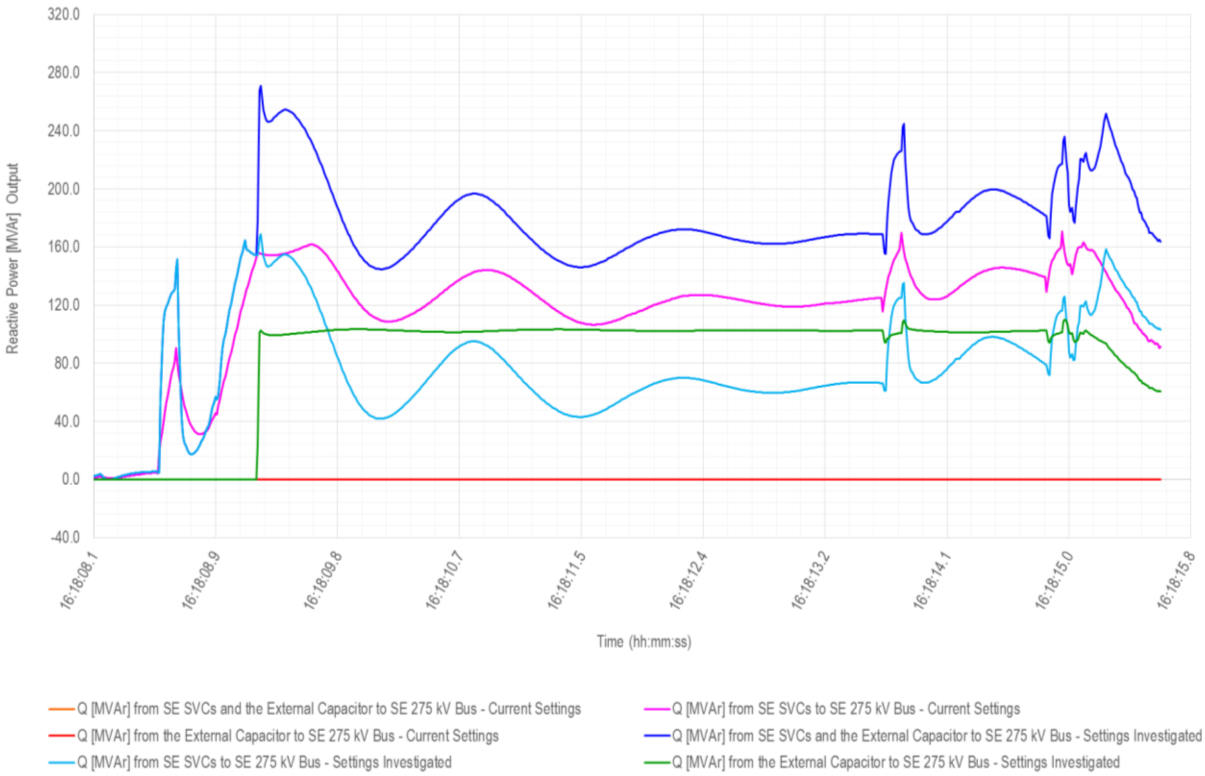


Figure 76 System voltages

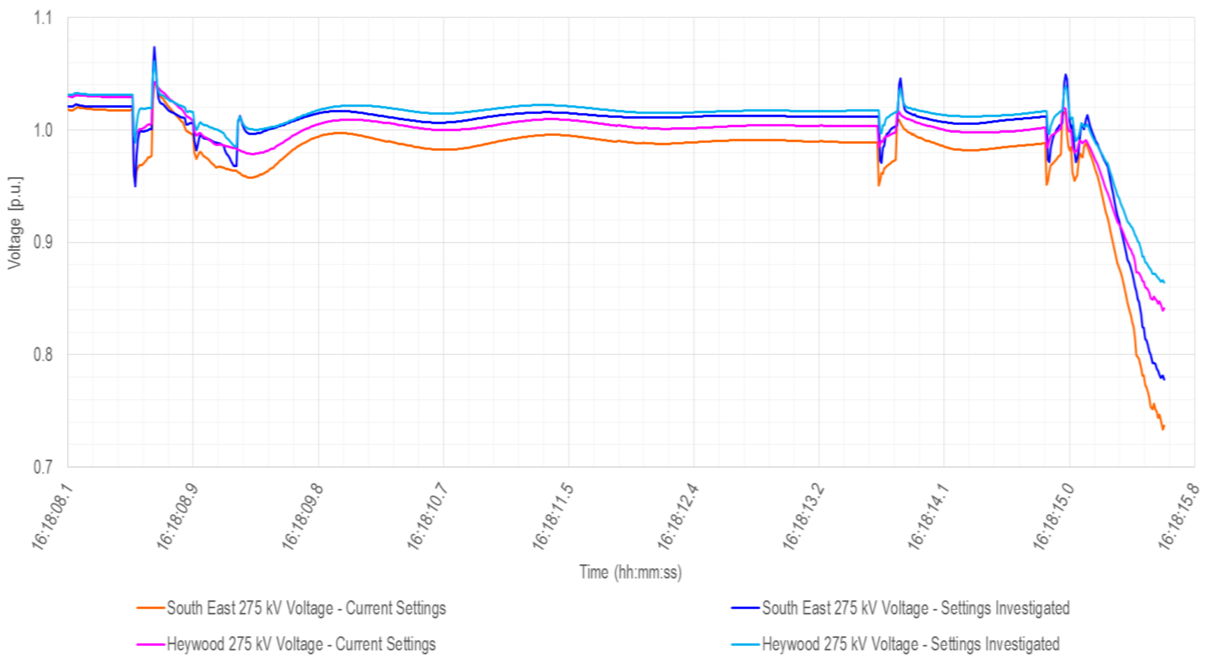
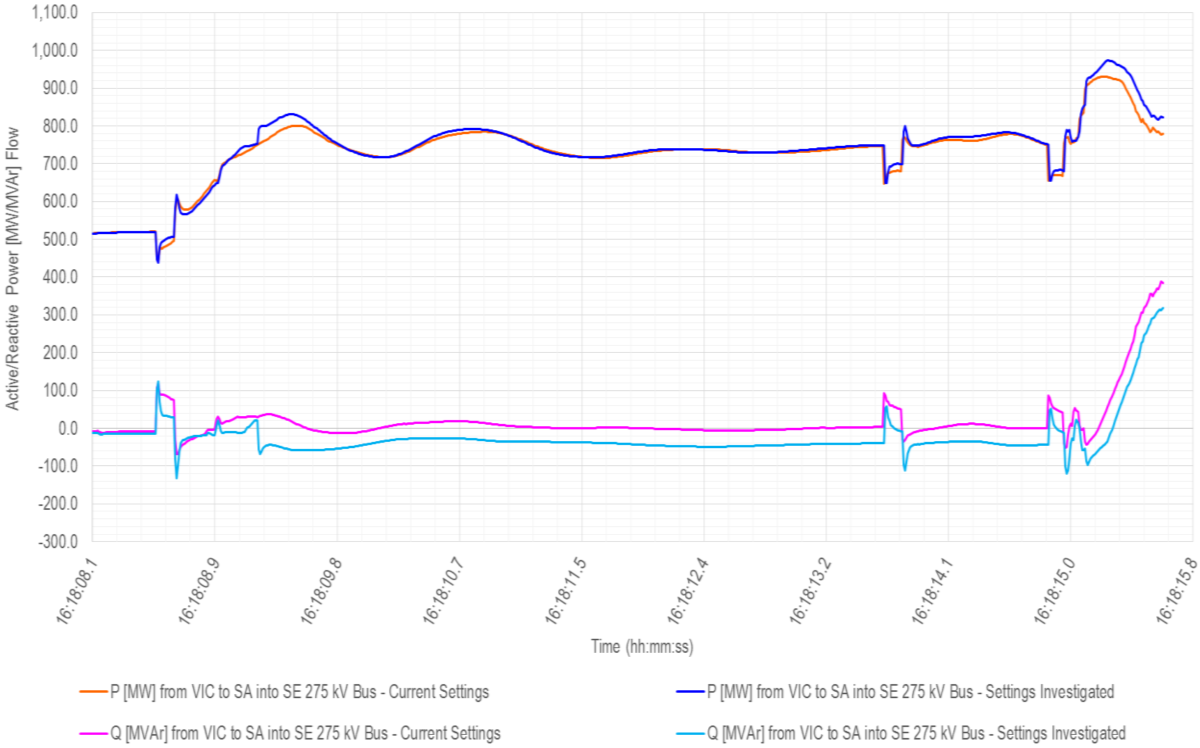


Figure 77 Active and reactive power transfer at Heywood Interconnector



APPENDIX M. NETWORK CAPABILITY ANALYSIS

This Appendix presents the results obtained from power system simulation studies carried out by AEMO to investigate the impact of transmission network line outages, and disconnection of a number of wind turbines due to high wind speed, provided that all wind farms were able to ride through a sufficient number of voltage disturbances in quick succession.

These studies built on static analyses including load flow and PV/QV studies (in Section M.1.1) presented in the third preliminary report.

They further investigated the stability and operability of the SA power system through power system dynamic studies carried out in PSS/E and PSCAD simulation tools.

M.1 Scenario 1: If wind farms did not reduce output due to the multiple voltage disturbances

M.1.1 Static analysis

Network operability with loss of three/four lines

Figure 78 Network capability with loss of three lines assuming no sustained power reduction by wind farms

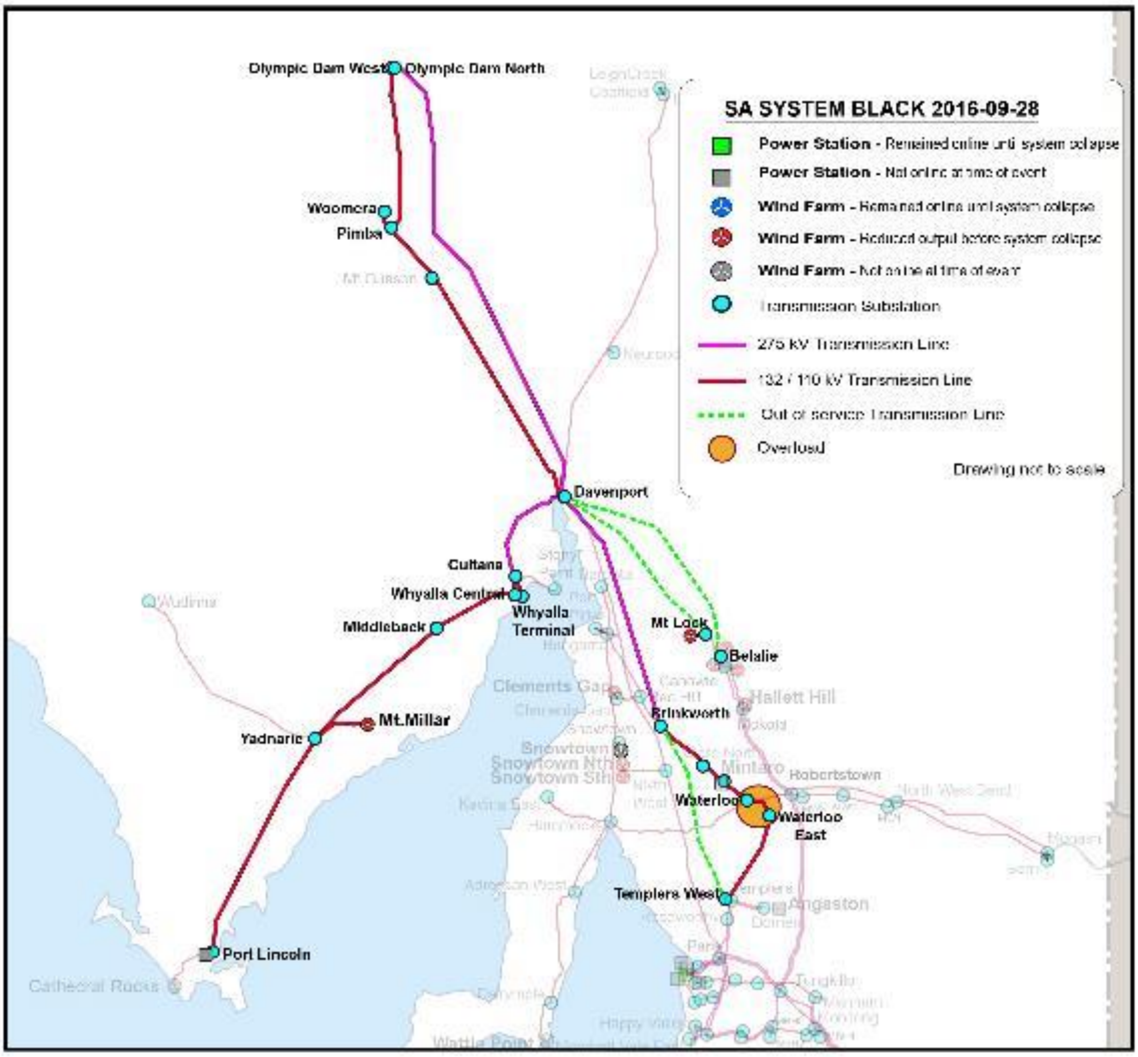
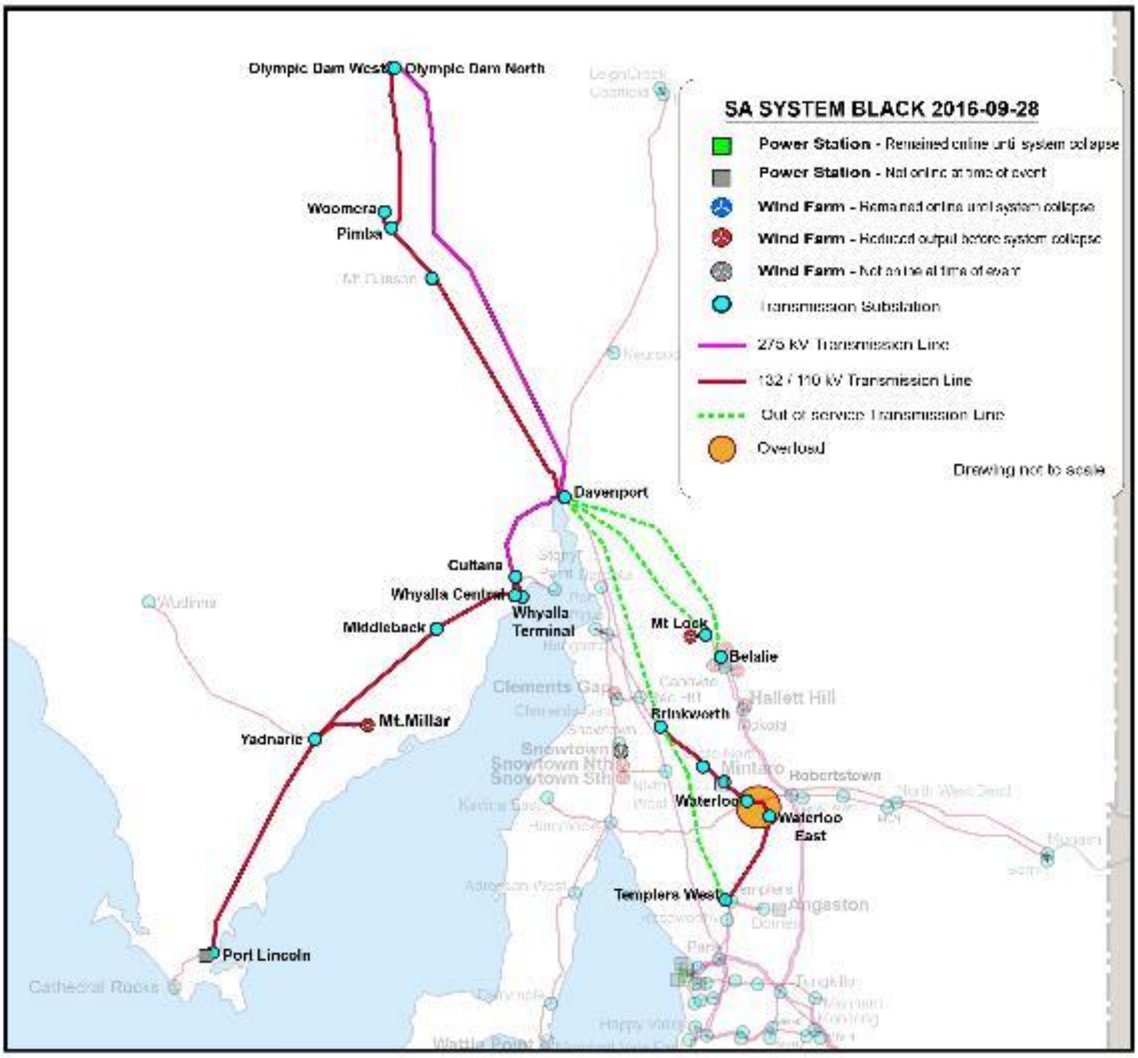


Figure 79 Network capability with loss of four lines assuming no sustained power reduction by wind farms



PV/QV analyses

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 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.

Heywood Interconnector

Figure 80 South East voltages versus Heywood transfers

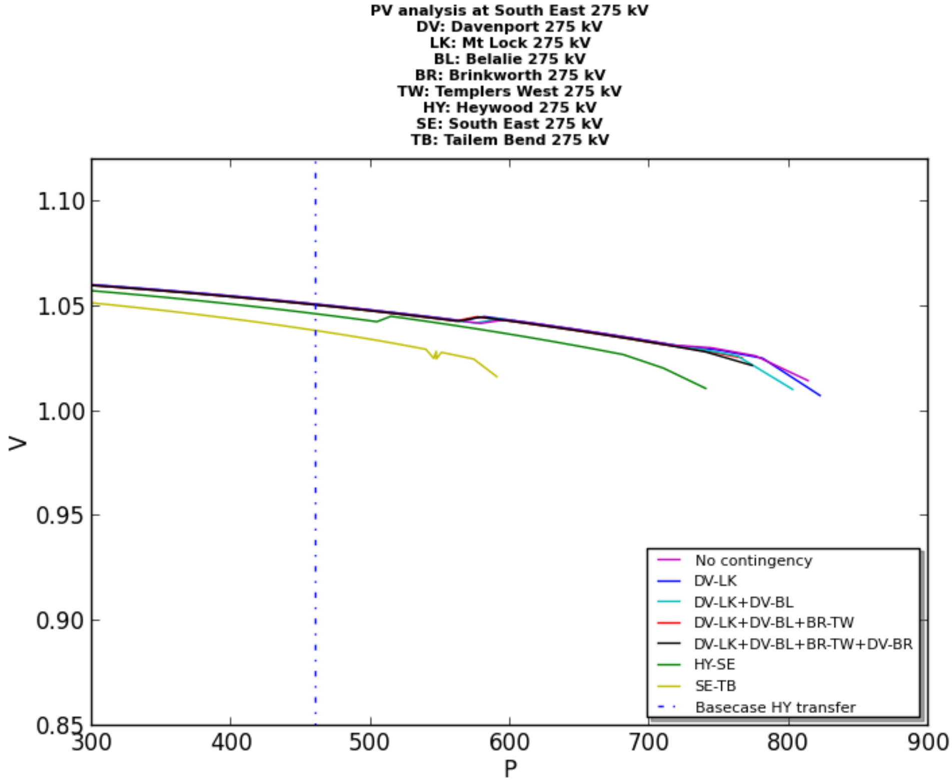


Figure 81 QV plots at South East with varying Heywood transfers (no contingency)

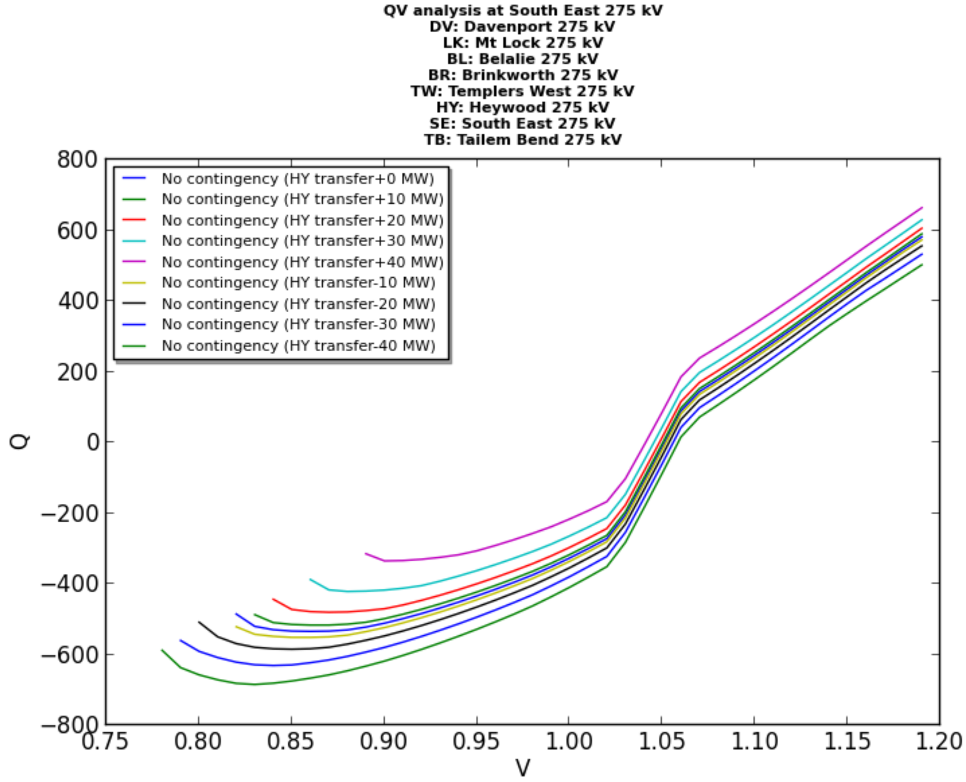
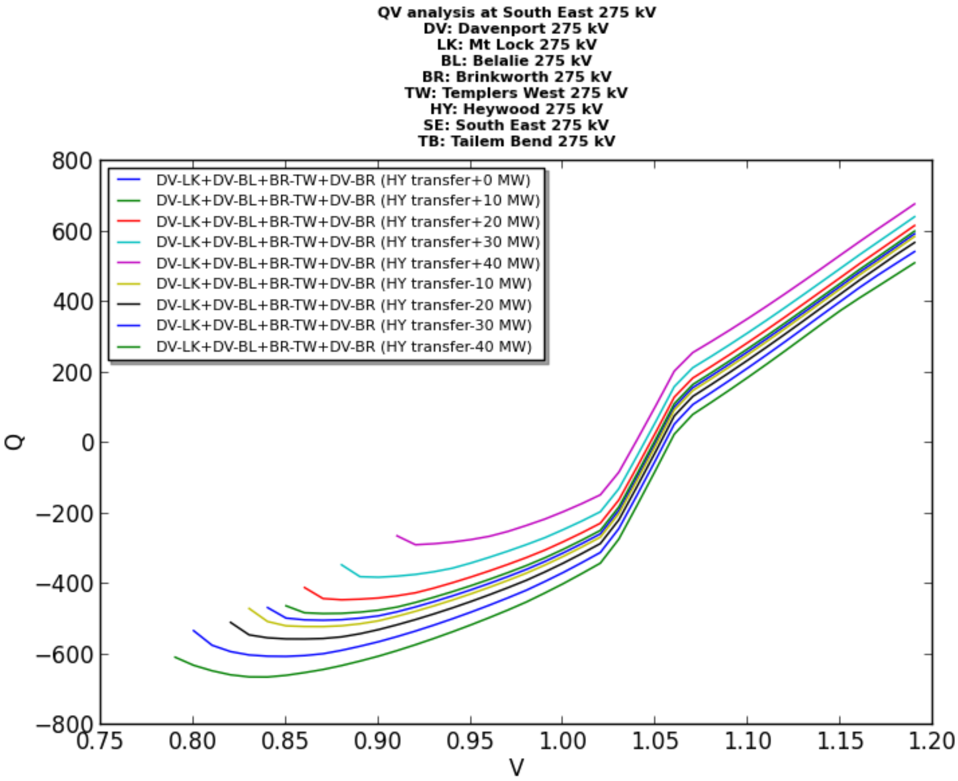


Figure 82 QV plots at South East with varying Heywood transfers (loss of four lines at Davenport)



Davenport

Figure 83 Davenport voltages versus Davenport demand

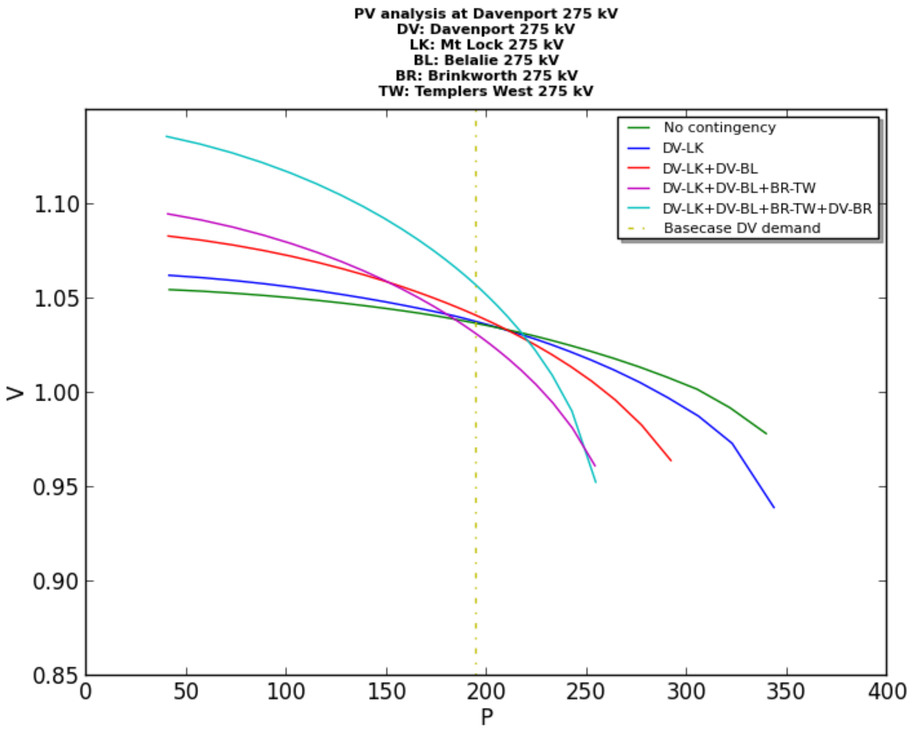


Figure 84 QV plots at Davenport with varying Davenport demand (no contingency)

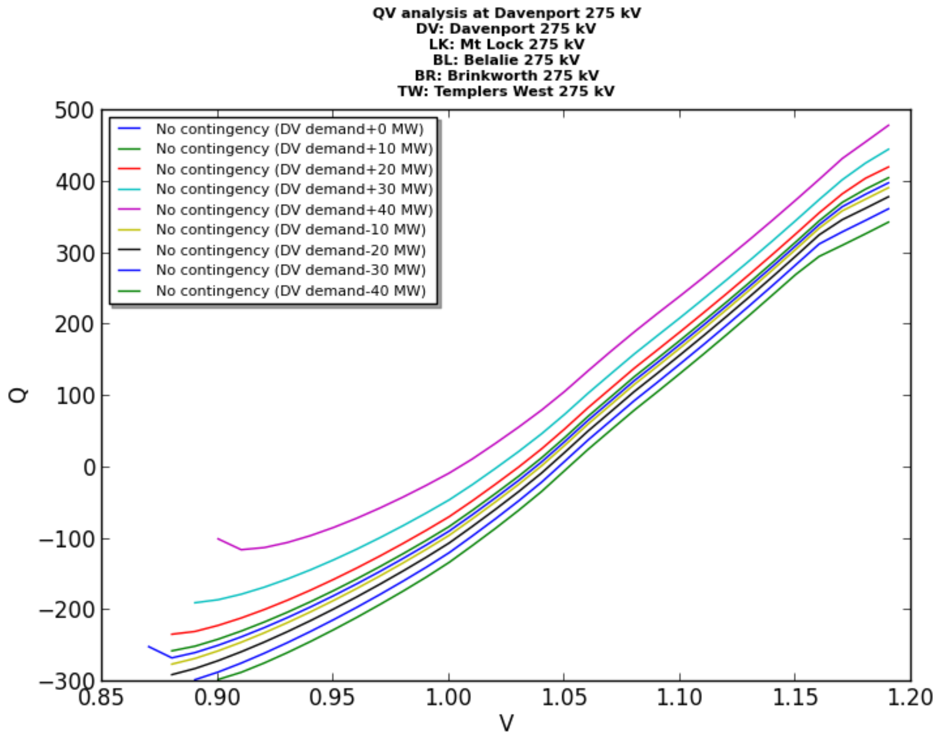
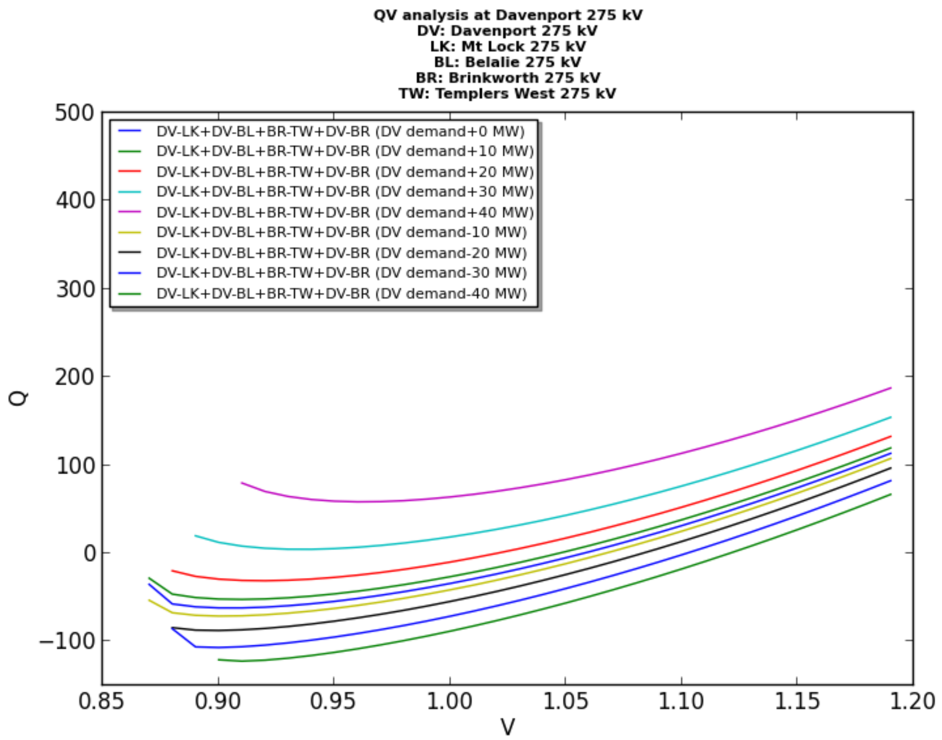


Figure 85 QV plots at Davenport with varying Davenport demand (loss of four lines in Davenport)



Robertstown

Figure 86 Para voltages versus Robertstown transfers

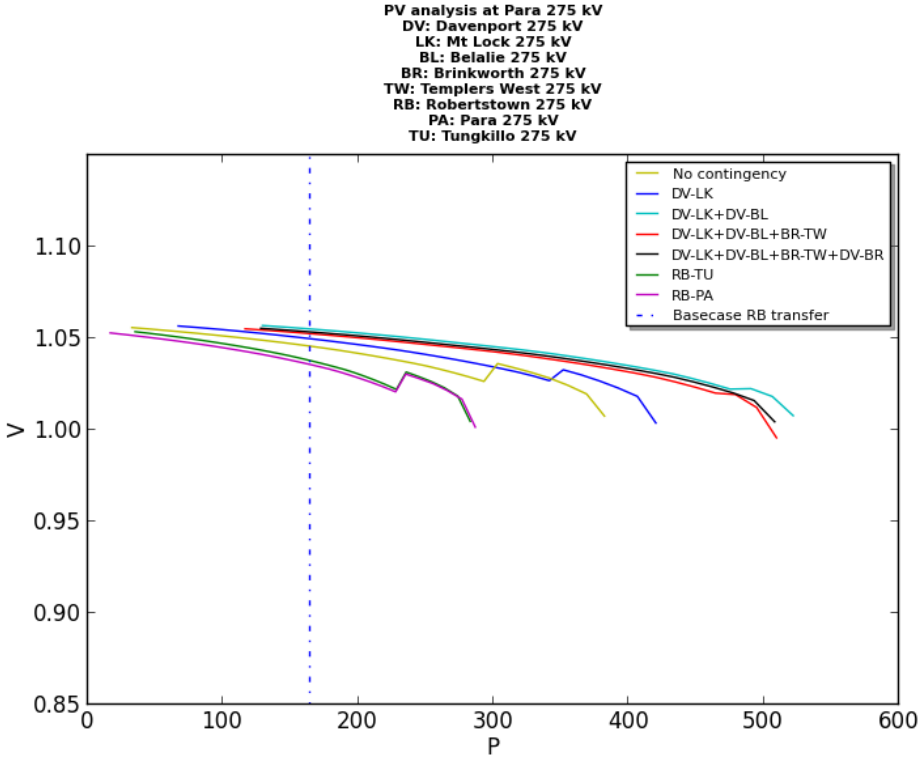


Figure 87 QV plots at Para with varying Robertstown transfers (no loss of line)

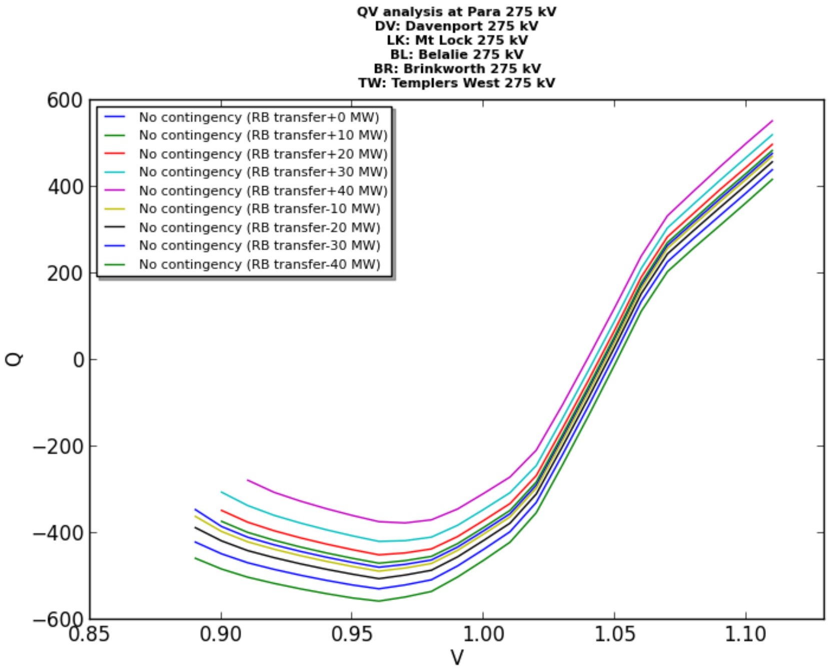
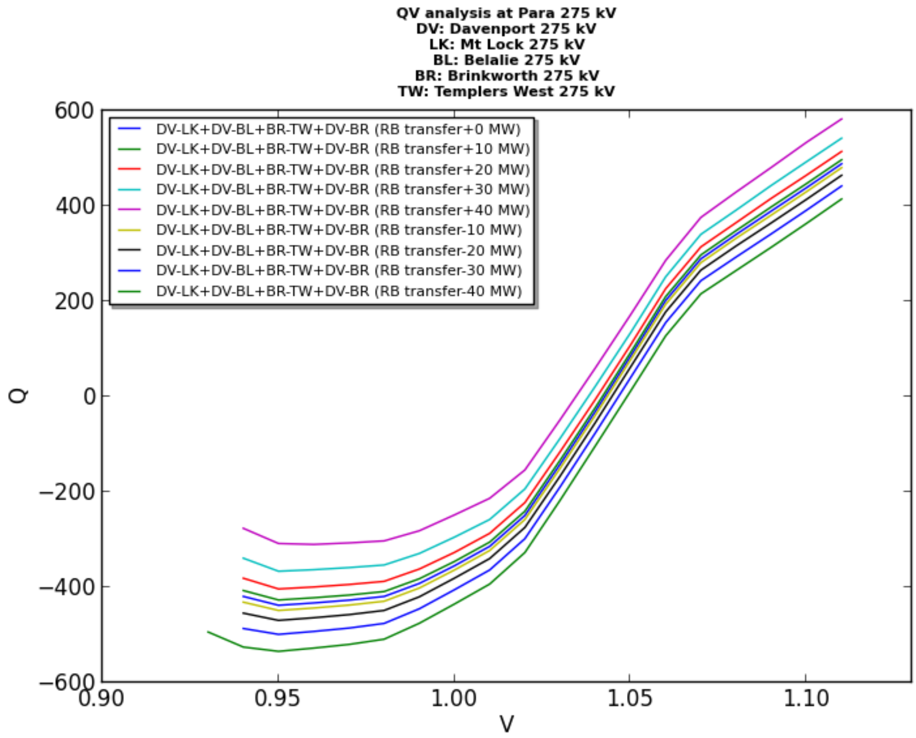


Figure 88 QV plots at Para with varying Robertstown transfers (loss of four lines at Davenport)



M.1.2 Dynamic analysis

Dynamic simulation studies were carried out using both PSS/E and PSCAD simulation tools, replicating the exact operating conditions and sequence of event leading to the Black System. This included:

- Disconnection of three/four transmission lines before/after the system separation.
- Dispatching all on-line wind farms and synchronous generators with the same active and reactive power levels.
- For wind farms with dual mode of operation (voltage control vs power factor control), the exact operating mode immediately before the event was obtained from ElectraNet and correctly implemented in the models.

Simulation studies were conducted with loss of three/four transmission lines and sustained power reduction by the Group C wind farm. This is because the Group C wind farm implements the zero power mode of operation in response to a single credible fault. The mechanism for sustained generation reduction for this wind farm, therefore, differs from those of the Group A and B wind farms.

In summary, both PSS/E and PSCAD simulation studies carried out by AEMO indicate that the SA power system would have remained stable and interconnected if the Group A and B wind farms had ridden through all the six voltage disturbances.

Figure 89 to Figure 100 show the dynamic simulation results obtained from the PSS/E and PSCAD studies, specifically:

- Figure 89 and Figure 95 indicate a stable response of the Heywood Interconnector, as evident from the simulated responses of active and reactive power.
- Figure 90 and Figure 96 show that the impedance trajectory seen by the Heywood loss of synchronism relay would have been far from the loss of synchronism relay characteristic area, indicating that system separation would not have occurred. This is further corroborated by:
  - Figure 92 and Figure 98, which highlight system voltage phase angles are maintained well below 90 degrees (around which loss of synchronism typically occurs).

- Figure 91 and Figure 97, which show healthy system voltage magnitudes that recover to pre-disturbance values shortly after the clearance of each fault.

- System frequencies would be maintained above 49.5 Hz indicating that no under frequency load shedding would occur.

PSS/E simulation studies

Figure 89 Active and reactive power transfer at Heywood Interconnector

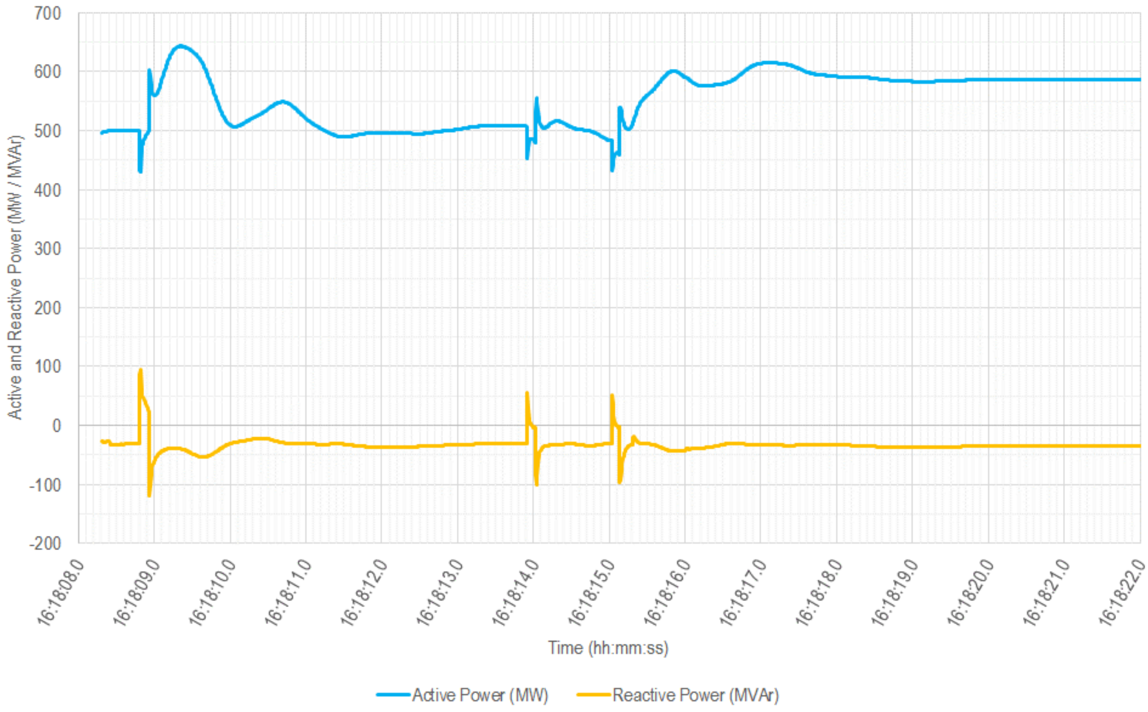


Figure 90 Impedance trajectory at Heywood Interconnector

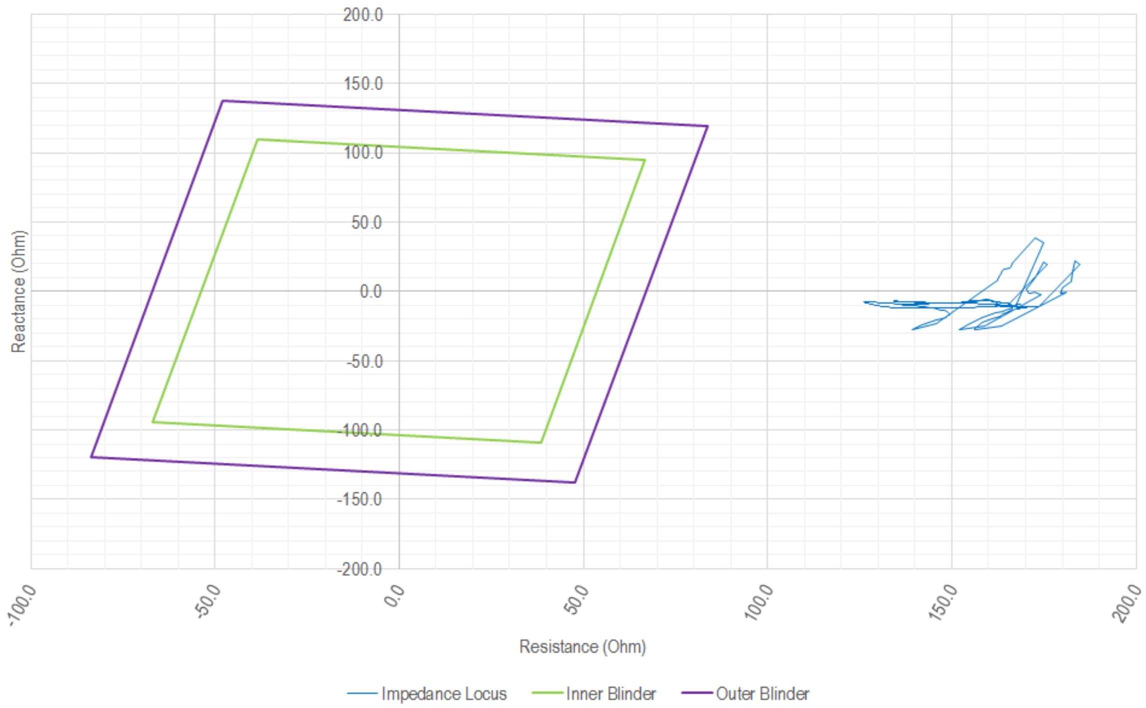


Figure 91 Voltage magnitudes at key SA 275 kV substations

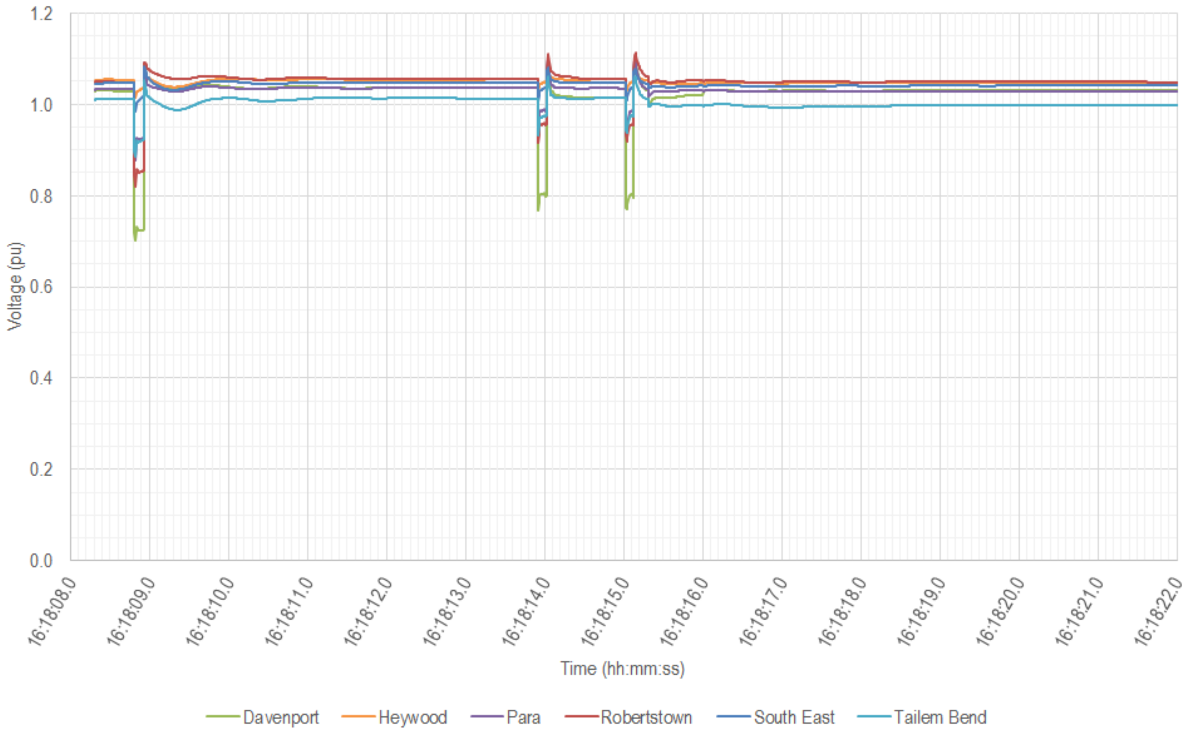


Figure 92 Voltage phase angles relative to HYTS at key SA 275 kV substations

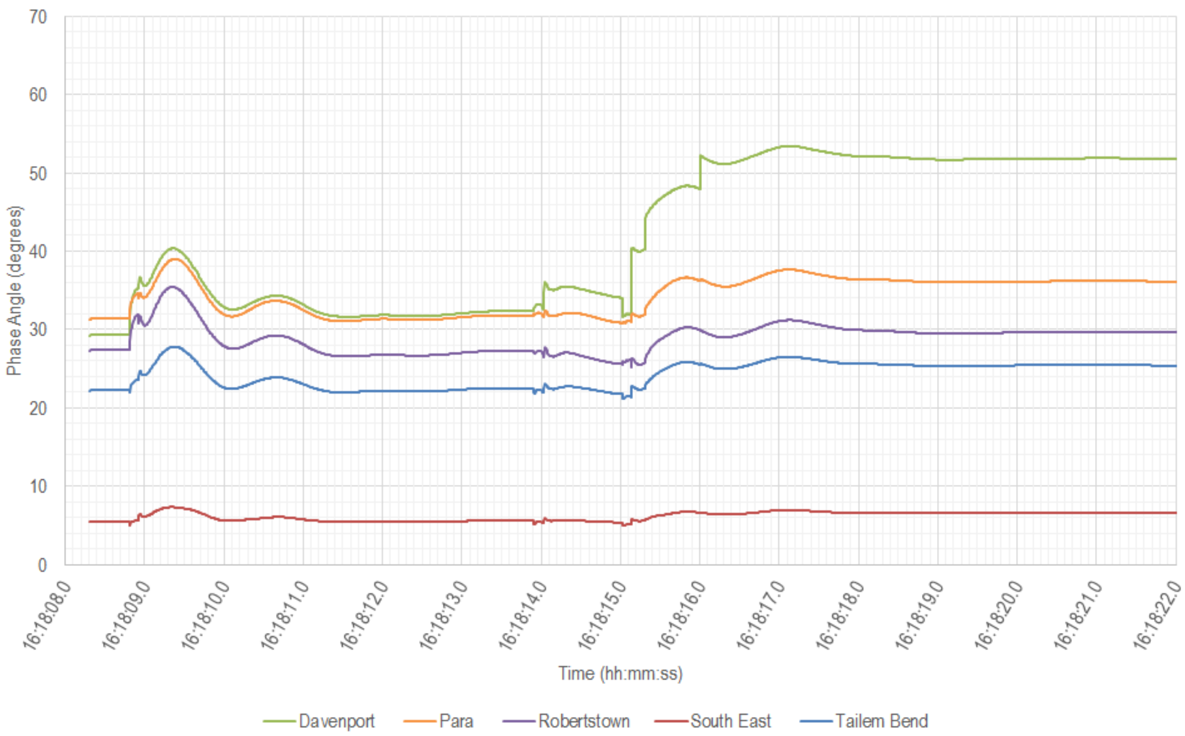


Figure 93 Frequencies at key SA 275 kV substations

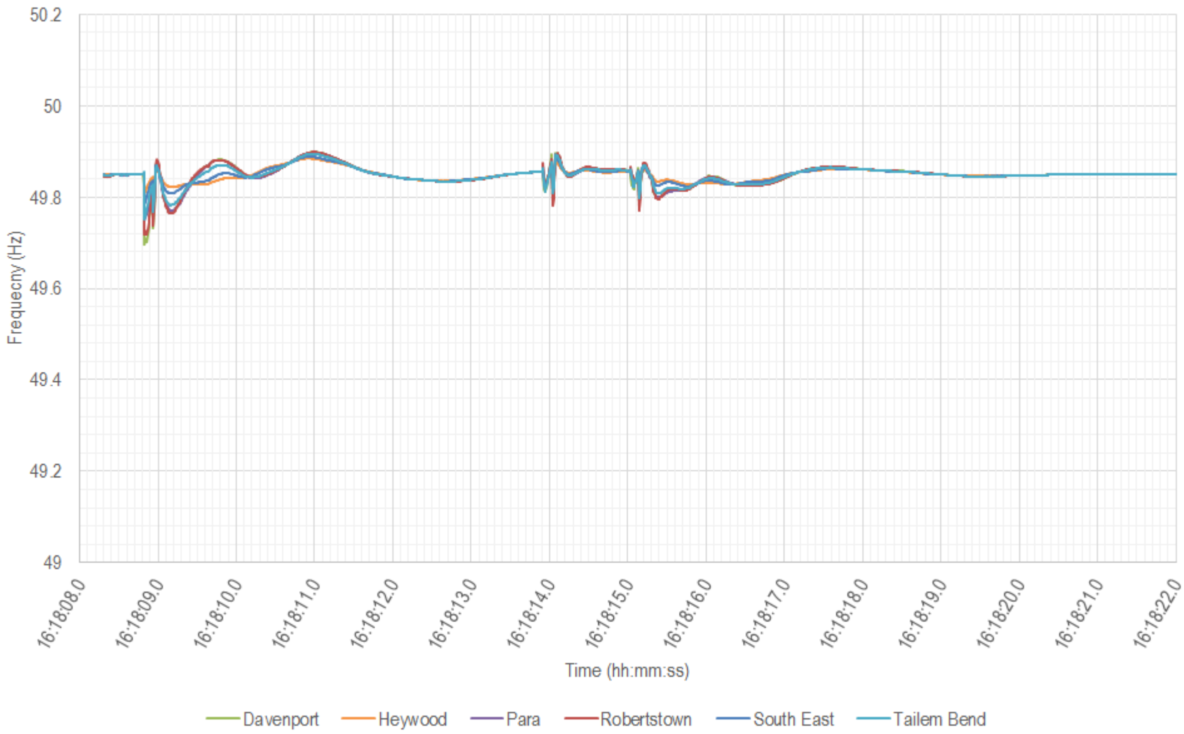
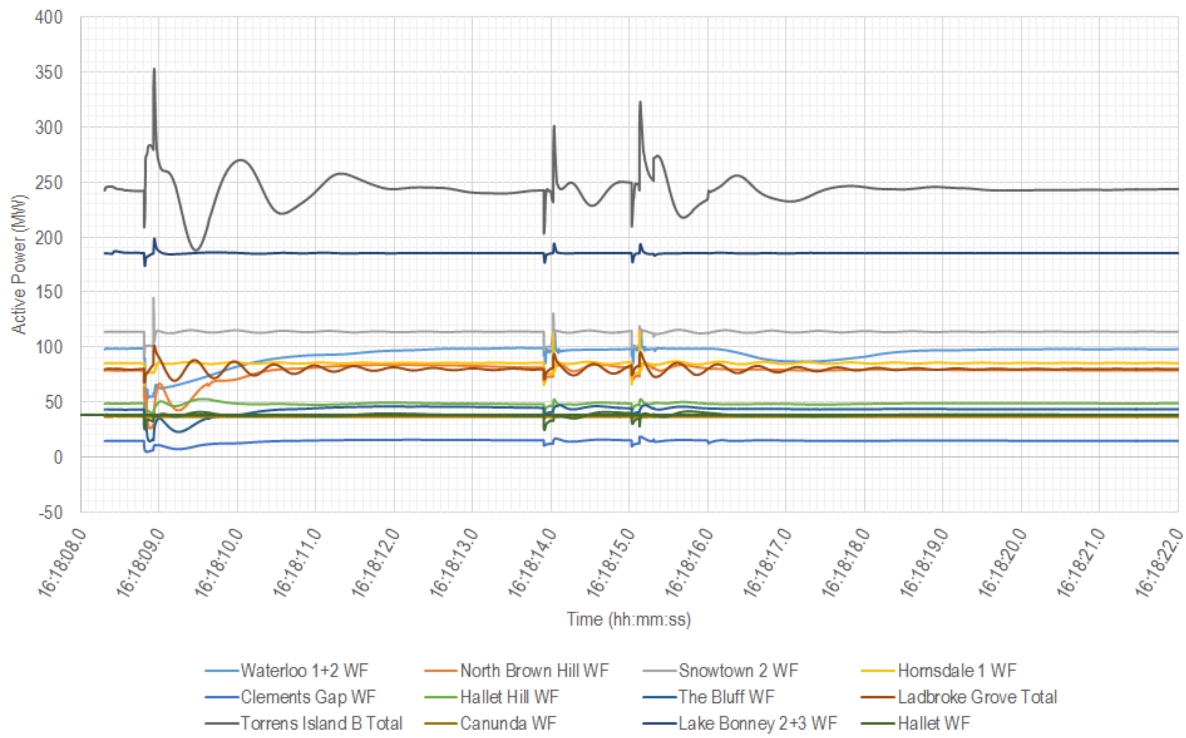


Figure 94 Individual generators' active power output



PSCAD simulation studies

Figure 95 Active and reactive power transfer at Heywood Interconnector

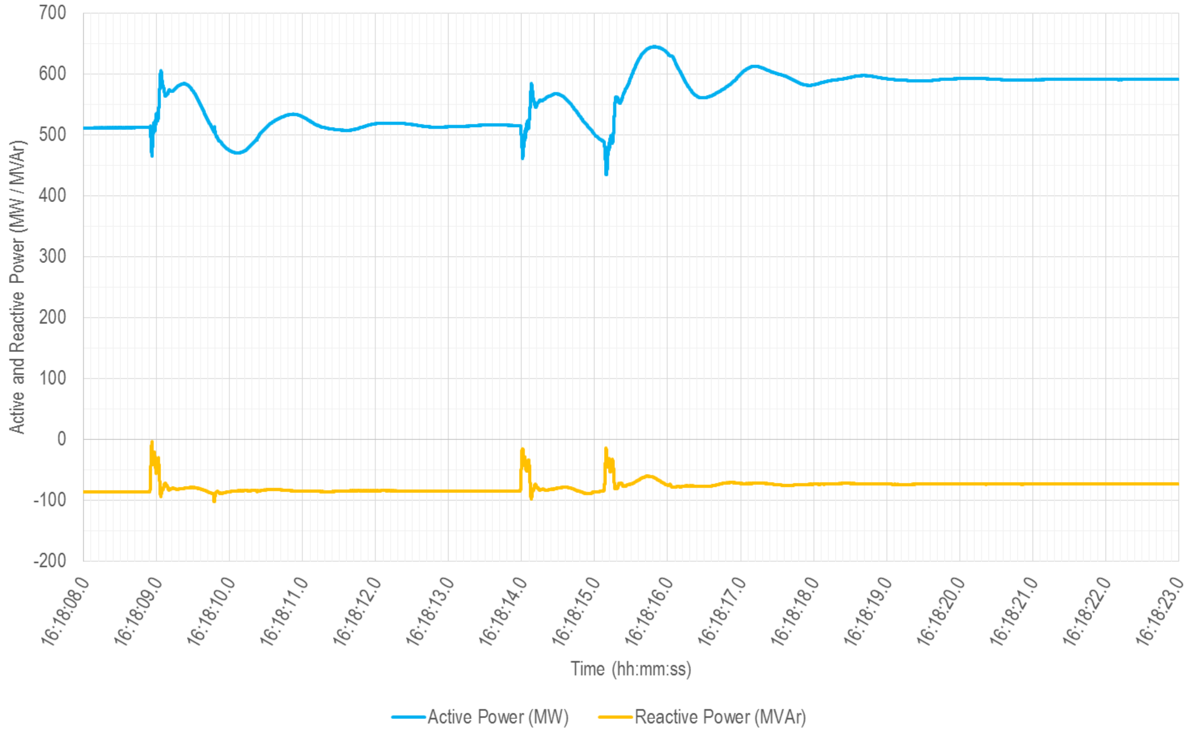


Figure 96 Impedance trajectory at Heywood Interconnector

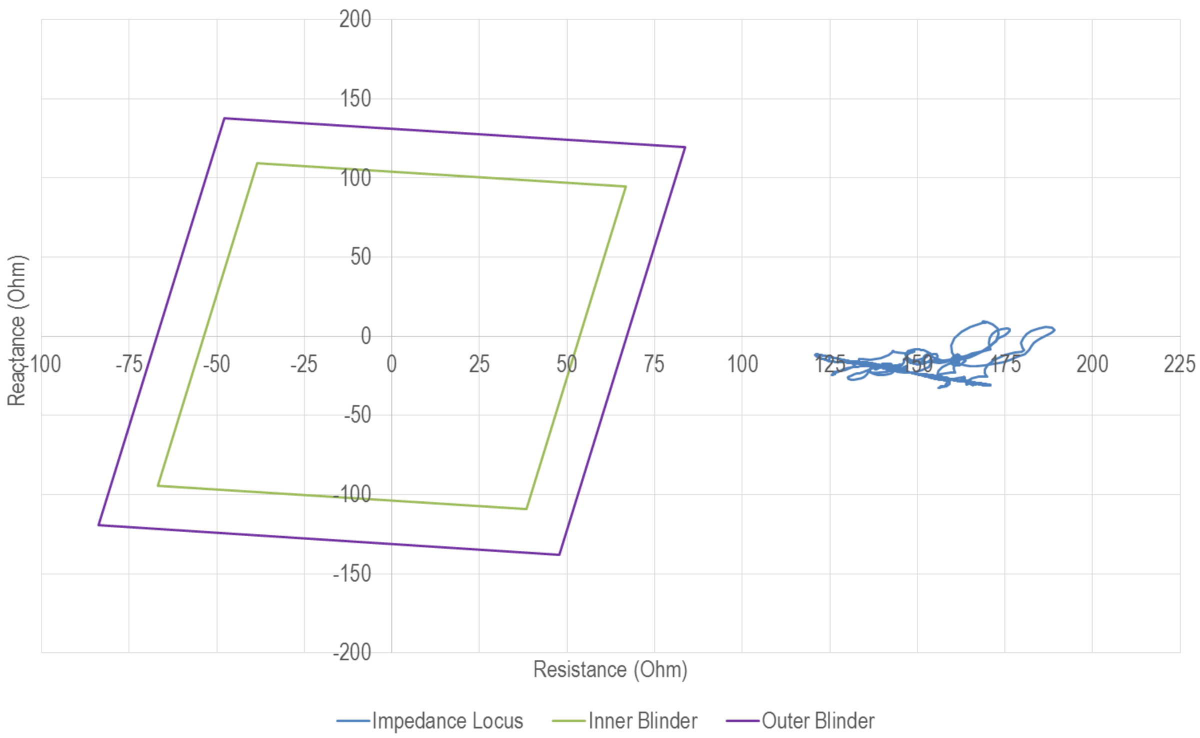


Figure 97 Voltage magnitudes at key SA 275 kV substations

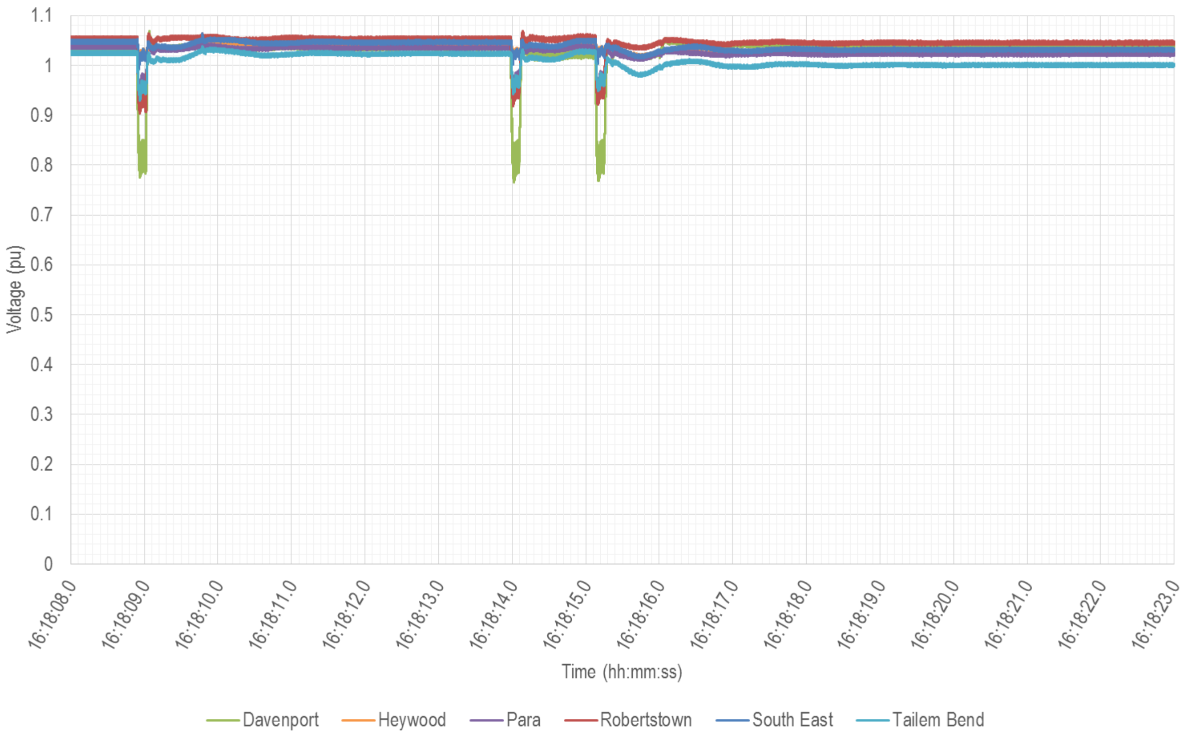


Figure 98 Voltage phase angles relative to HYTS at key SA 275 kV substations

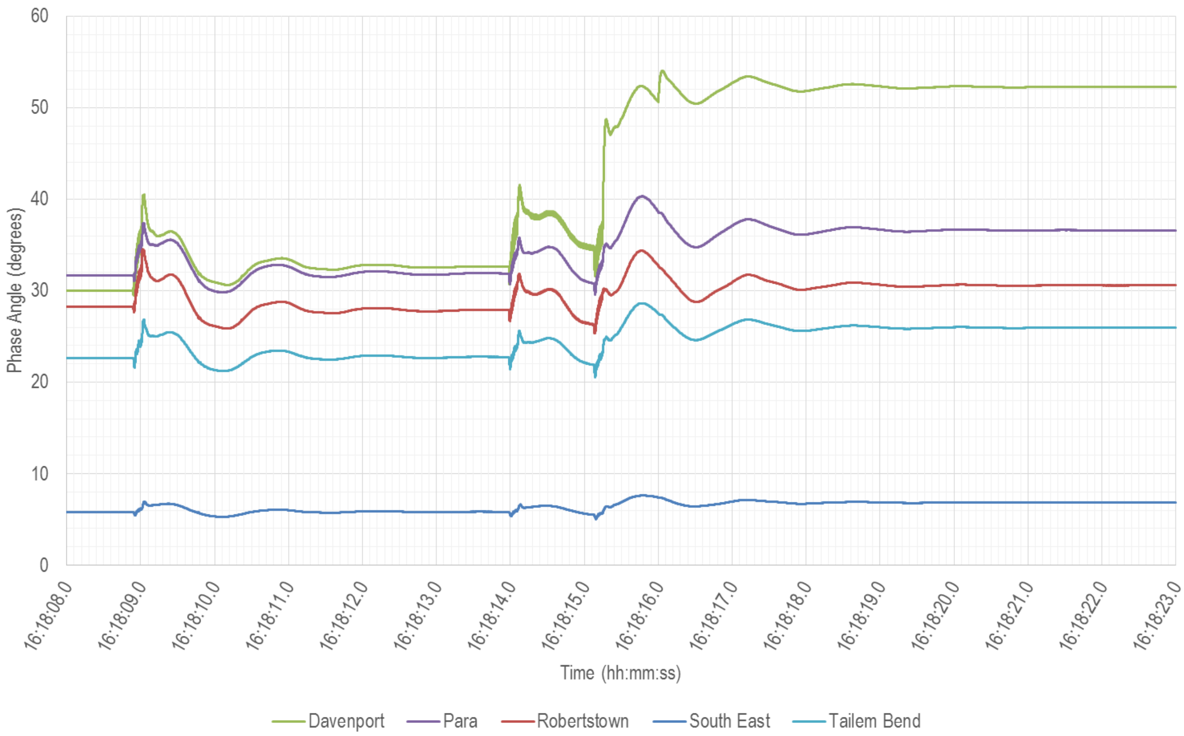


Figure 99 Frequencies at key SA 275 kV substations

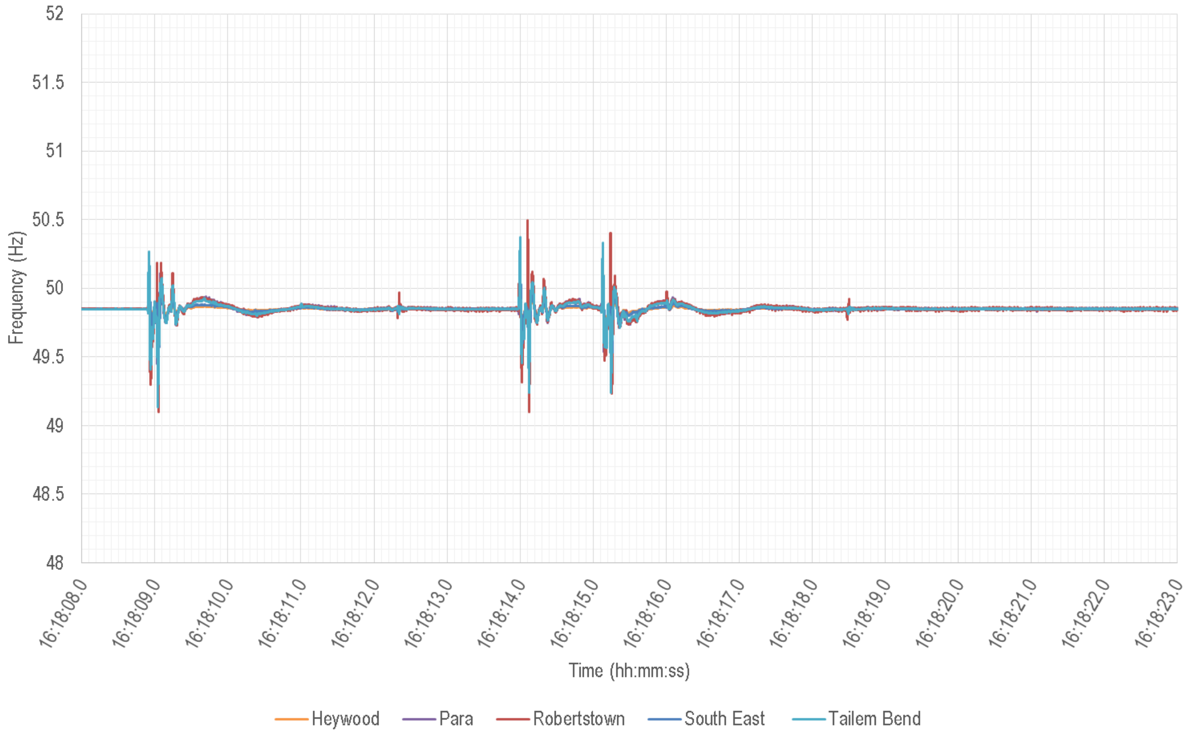
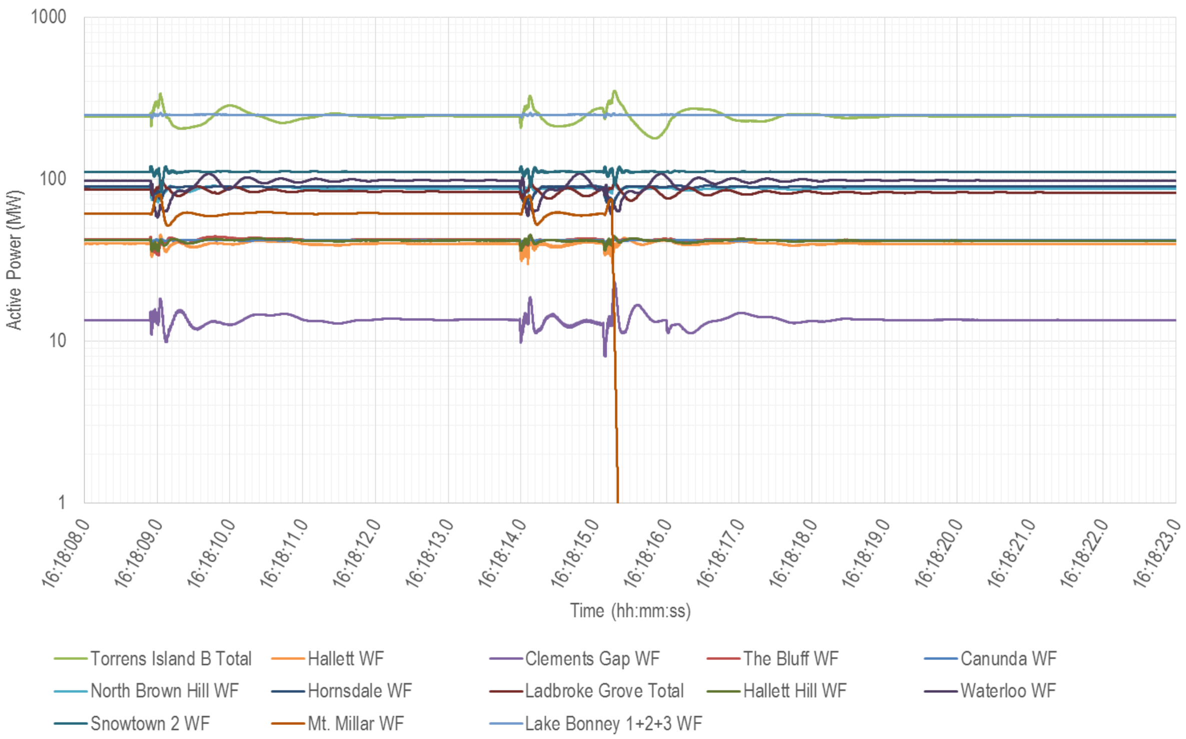


Figure 100 Individual generators' active power output



M.2 Scenario 2: Scenario 1, with an additional loss of wind generation due to high wind speeds

The scenario investigated in this section is an extension of Scenario 1. In Scenario 2, it has been assumed that all wind farms successfully rode through all six voltage disturbances, and 200 MW of wind generation was disconnected after the loss of the fourth transmission line due to high wind speed conditions.

The 200 MW figure was chosen as a pessimistic estimate of the amount of wind generation that could have been disconnected in the several minutes after system separation, and assuming that the three on-line TIPS B units or Murraylink HVDC link would not increase their active power contribution in subsequent dispatch intervals.

The resultant loss of wind generation due to high wind speed would therefore be completely reflected onto the Heywood Interconnector, leading the Interconnector import to stabilise at around 800 MW with healthy voltage magnitudes and phase angles throughout the SA power system. The loss of synchronism relay would have correctly remained unresponsive to this stable power swing.

In summary, both PSS/E and PSCAD simulation studies carried out by AEMO consistently demonstrate that the SA power system would have remained stable and interconnected with loss of i) four transmission lines, ii) 200 MW of wind generation due to high wind speed, and iii) zero power mode of Mt Millar Wind Farm.

PSS/E simulation studies

Figure 101 Active and reactive power transfer at Heywood Interconnector

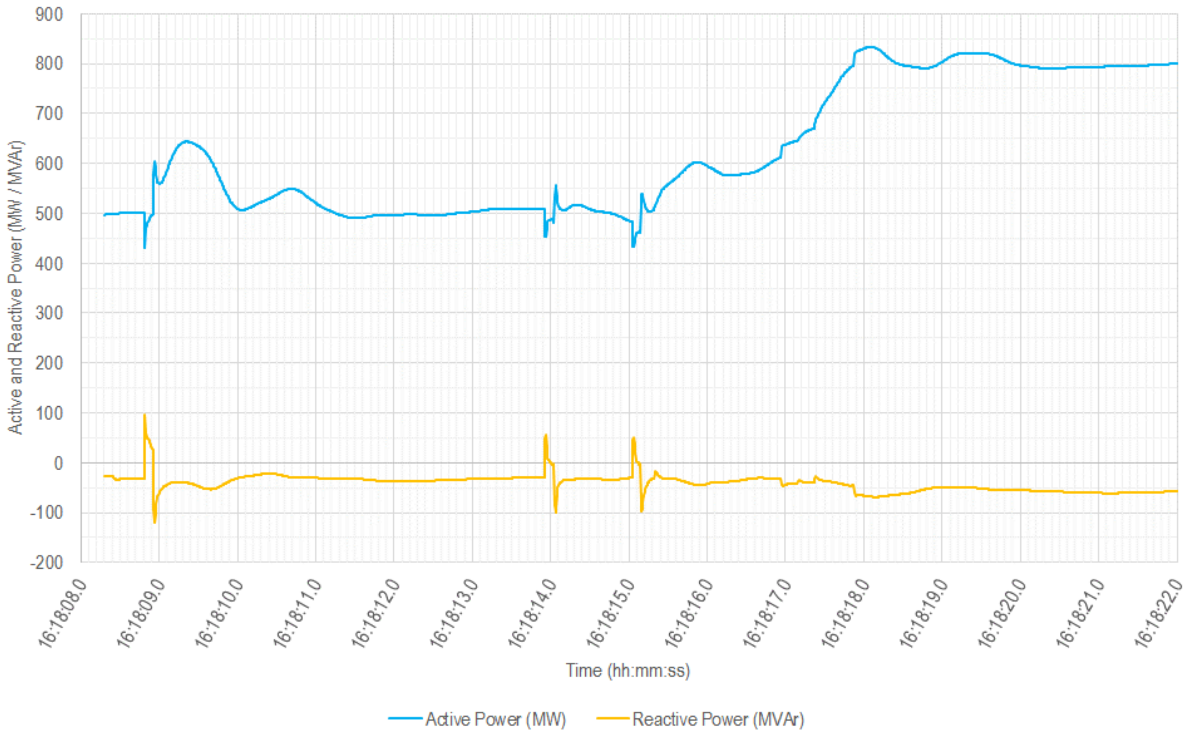


Figure 102 Impedance trajectory at Heywood Interconnector

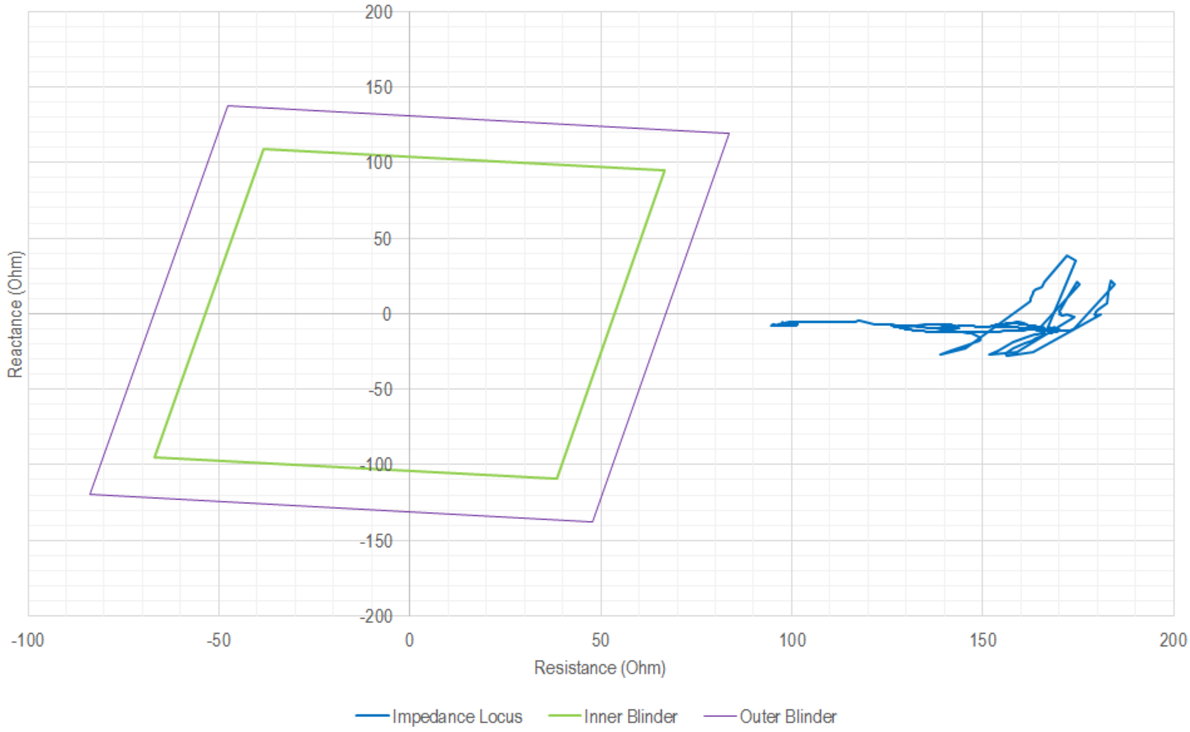


Figure 103 Voltage magnitudes at key SA 275 kV substations

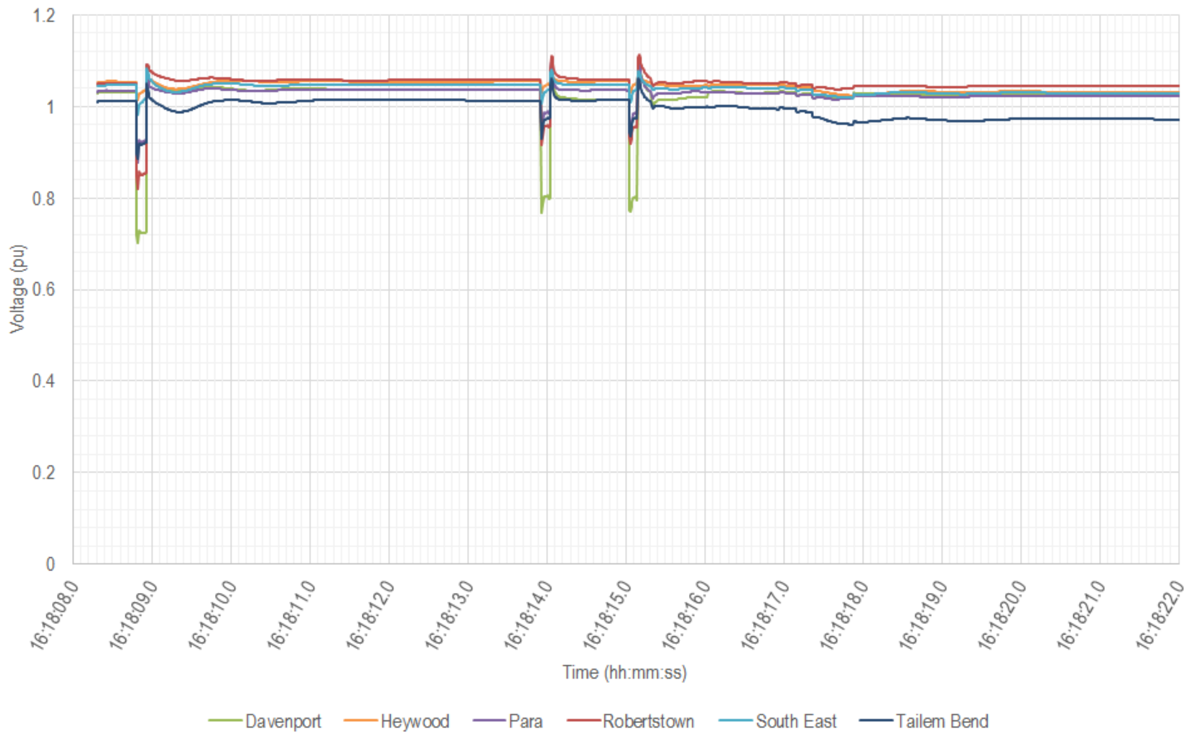


Figure 104 Voltage phase angles relative to HYTS at key SA 275 kV substations

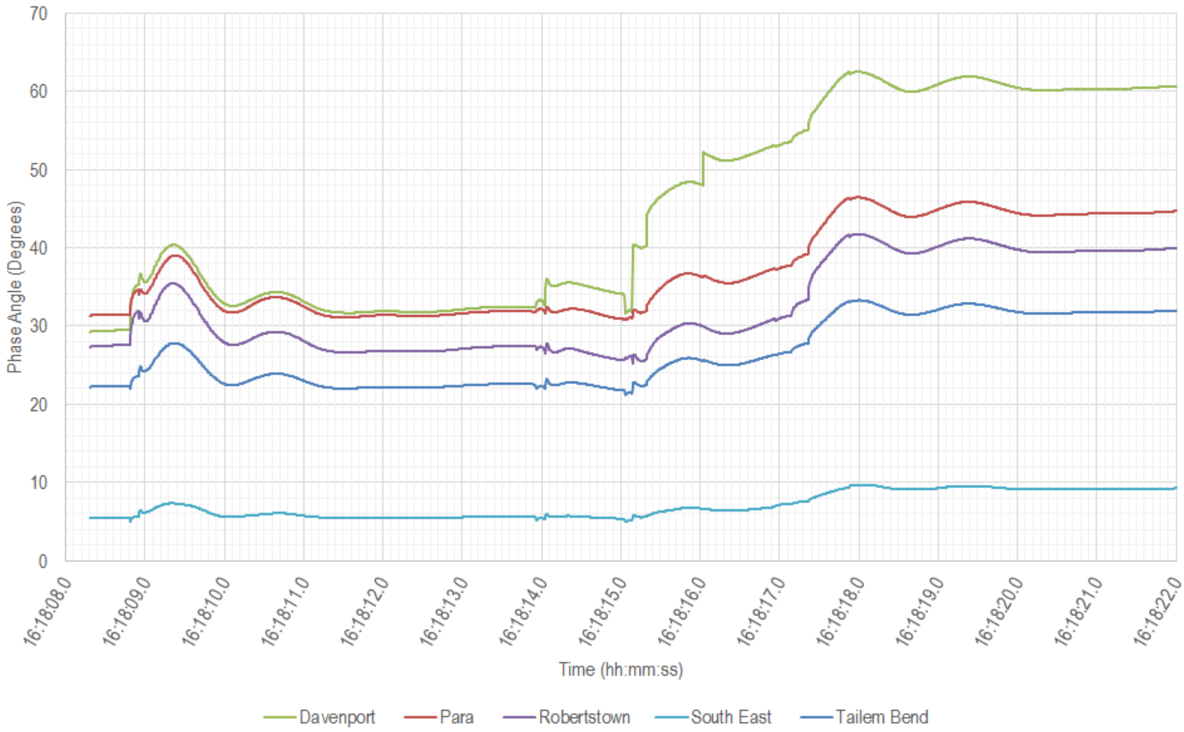
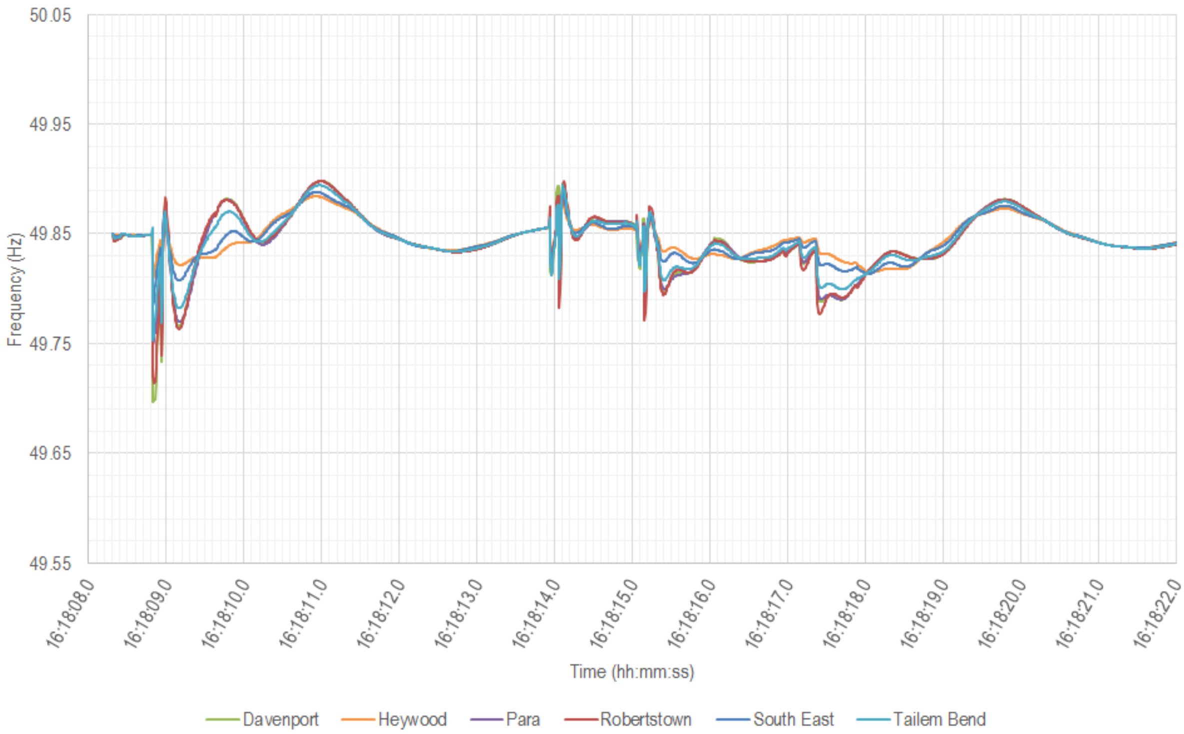


Figure 105 Frequencies at key SA 275 kV substations



PSCAD simulation studies

Figure 106 Active and reactive power transfer at Heywood Interconnector

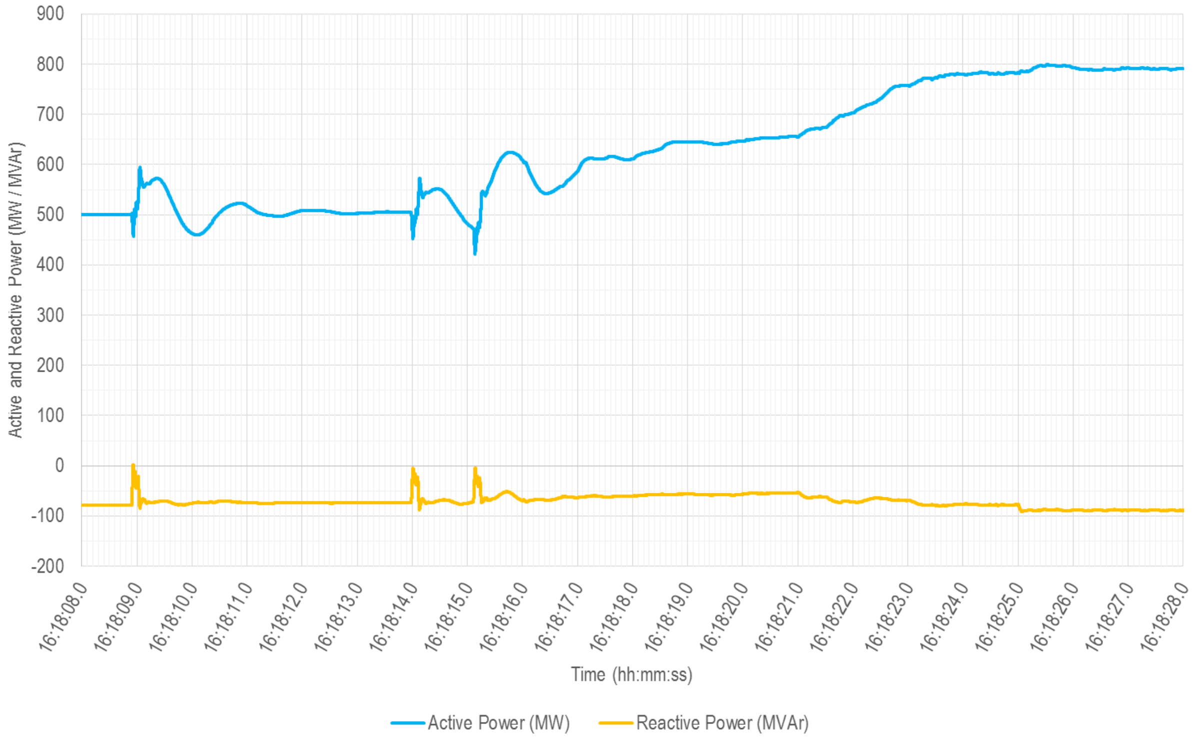


Figure 107 Impedance trajectory at Heywood Interconnector

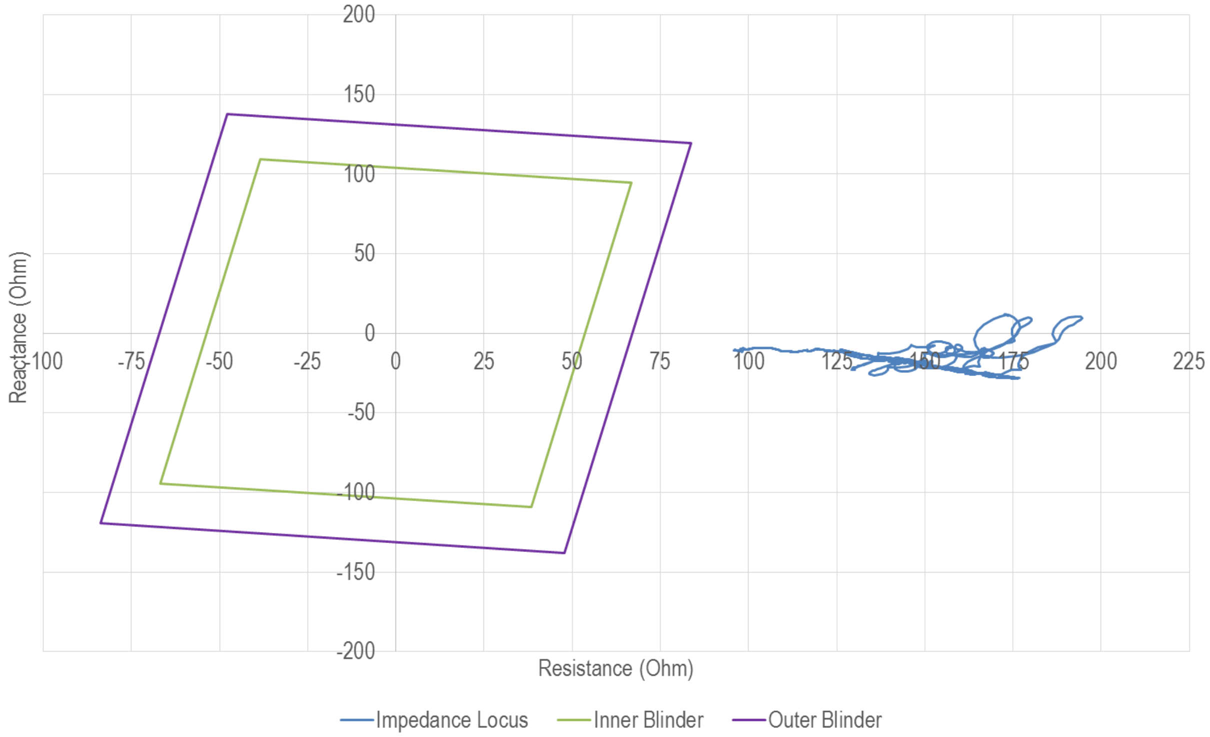


Figure 108 Voltage magnitudes at key SA 275 kV substations

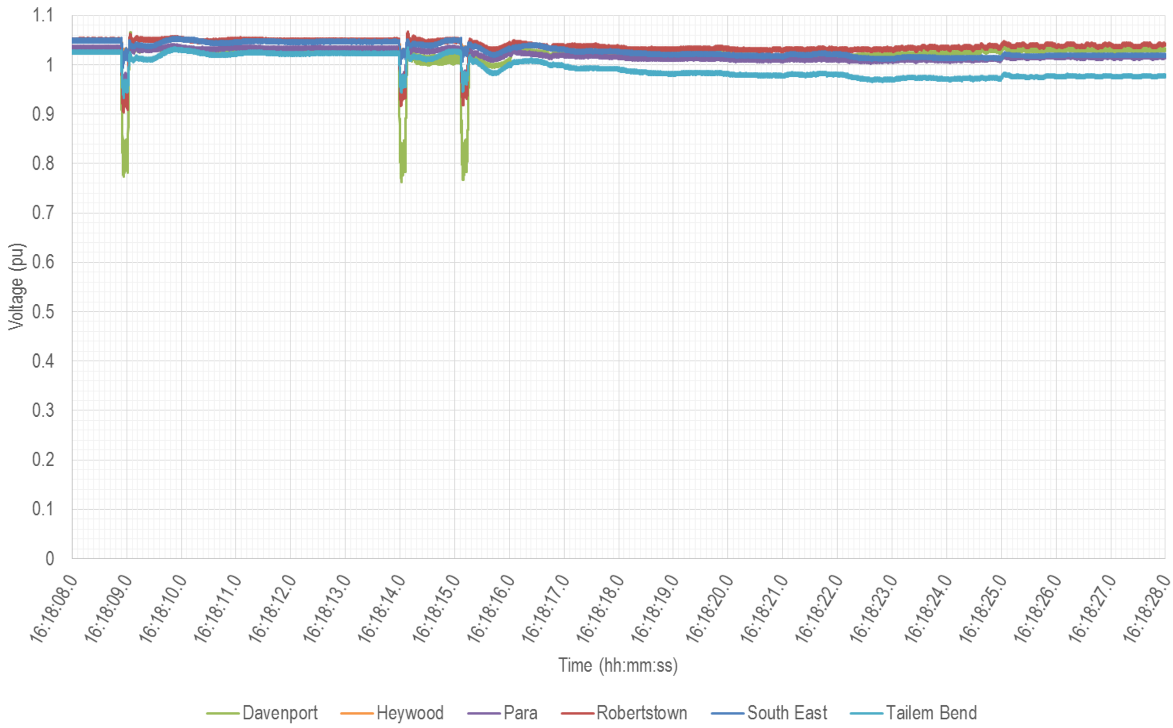


Figure 109 Voltage phase angles relative to HYTS at key SA 275 kV substations

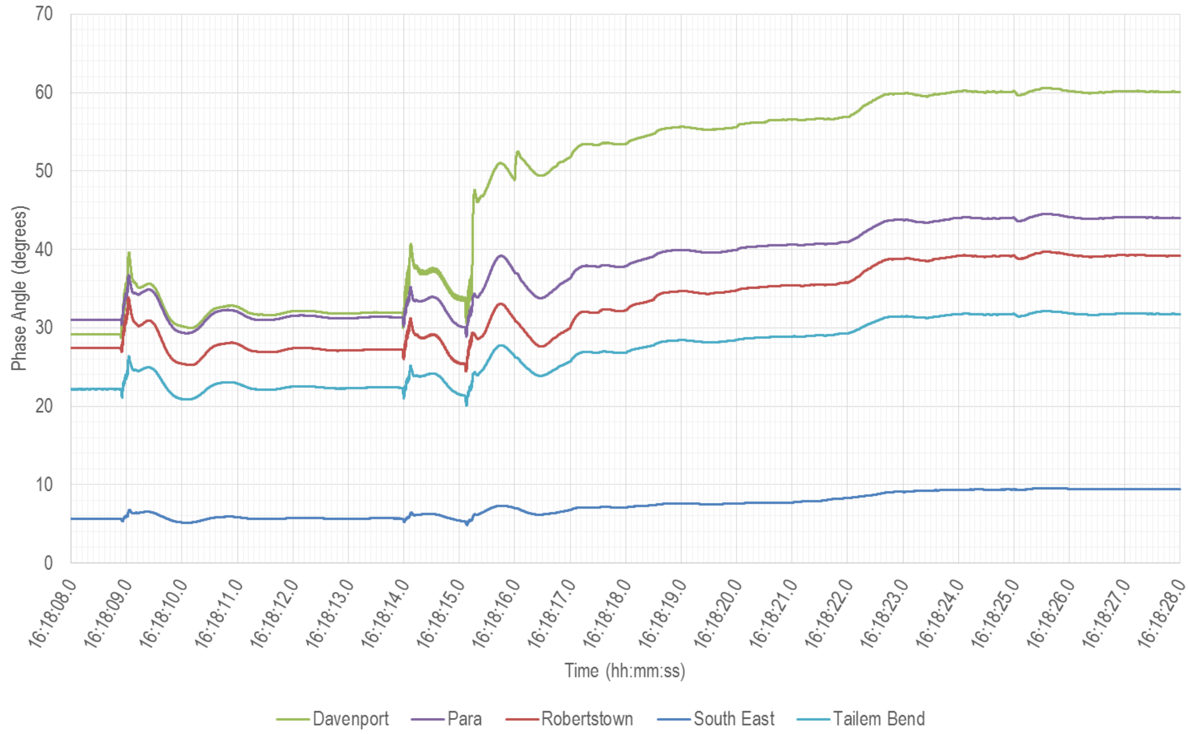


Figure 110 Frequencies at key SA 275 kV substations

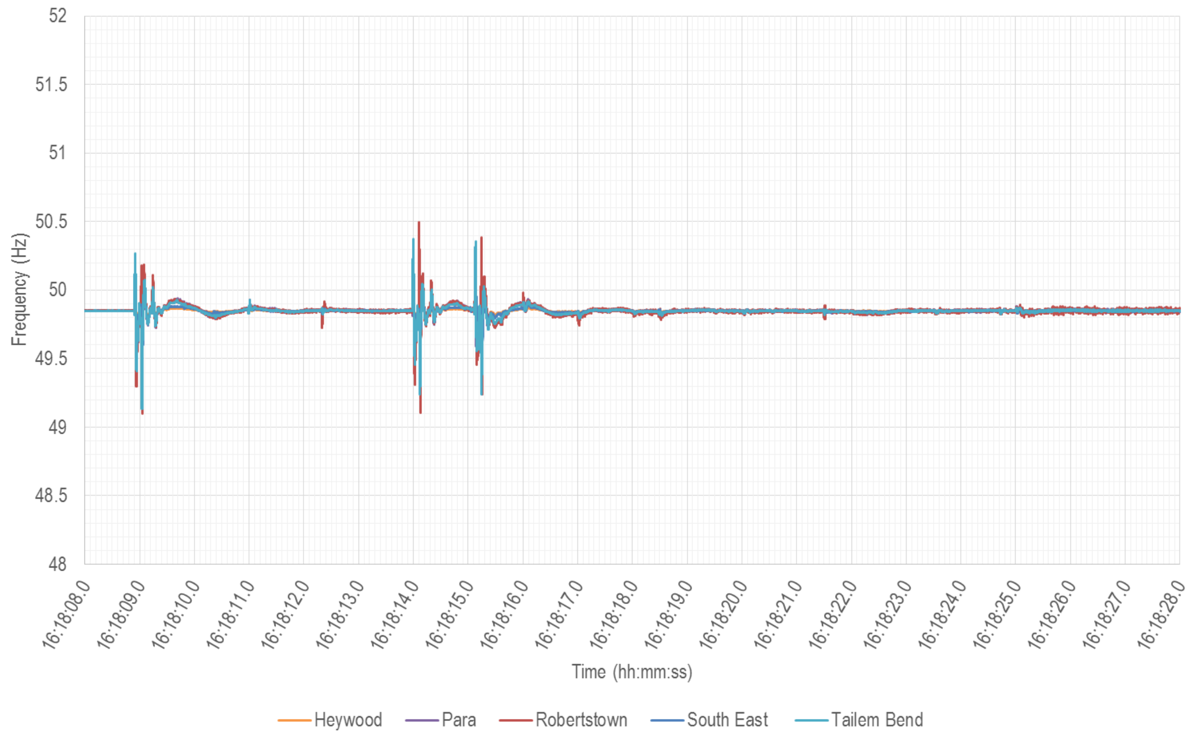
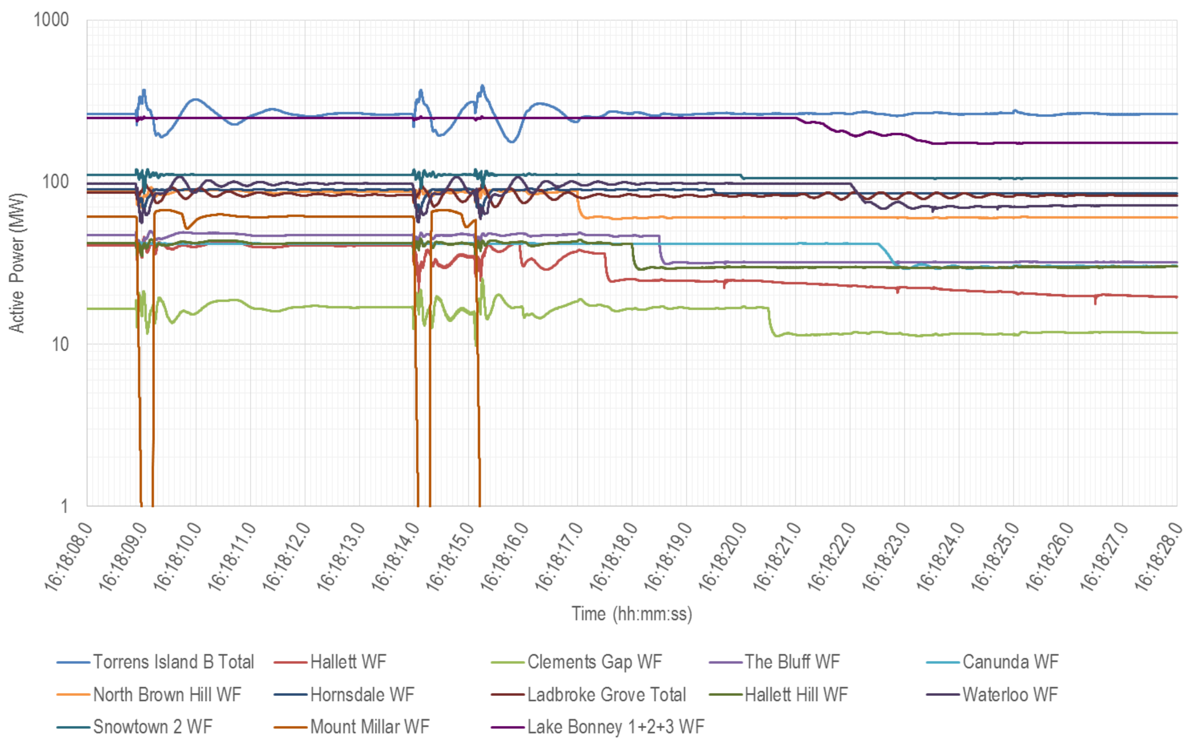


Figure 111 Individual generators' active power output



M.3 Scenario 3: If AEMO had received information on wind ratings of vulnerable transmission lines and had reclassified the multiple loss of lines for those lines where advised wind ratings were less than forecast wind speeds

Prior to 28 September 2016, AEMO's procedures for reclassifying the loss of multiple transmission lines in SA as credible contingencies identified several 275 kV corridors between Robertstown and the Victorian border as being potentially vulnerable to bushfires. Reclassification constraint equations were available for these events.

No transmission lines in SA were considered at this time to be potentially vulnerable to a multiple contingency event under high wind conditions. This event had not previously occurred, and historical performance is used to identify triggers and possible vulnerable lines for such weather events.

The Power System Security Working Group (PSSWG) develops and reviews reclassification criteria for abnormal events. Existing lightning and bushfire reclassification criteria were developed by this working group. The PSSWG is now working to identify specific transmission line reclassification criteria for high winds during storms.

Following the Black System, AEMO has sought further advice from TNSPs on transmission lines potentially vulnerable to failure under high wind speed conditions. Initial advice is that TNSPs do not typically have single wind ratings for their transmission lines, and it is a complex task to assess, as each line was constructed at different times, and to different historical standards. Local terrain is also a factor.

In SA, ElectraNet has advised that these specific lines may be vulnerable to high wind speeds.

The following 275 kV transmission lines are capable of withstanding wind gusts up to 106 km/h:

- Brinkworth–Davenport 275 kV line.
- Brinkworth–Templers West 275 kV line.
- Para–Templers West 275 kV line.
- Torrens A (TIPS A)–Magill 275 kV line.

The following transmission lines are capable of withstanding wind gusts up to 165 km/h:

- Davenport–Mt Lock 275 kV line (with temporary structures).
- Davenport–Belalie 275 kV (with temporary structures).

On the basis of this information, AEMO has now developed an operational process for responding to severe wind warnings in SA.

After receiving notification of severe weather warnings or severe thunderstorm warnings in the Mt Lofty Ranges, Mid North, or Flinders district, AEMO’s control room may, after consultation with ElectraNet, reclassify the loss of multiple transmission lines from this list as credible, based on information on the likely location of the severe wind conditions.

At this point, contingency definitions in AEMO’s real-time contingency analysis tools will be updated to consider these multiple contingency events.

However, offline power system analysis has determined that no additional reclassification constraints are required for this reclassification, because:

- Existing system normal dispatch constraint equations have been assessed as adequate to manage power system security for some these multiple transmission line reclassifications.
- For other reclassifications, local under voltage load shedding schemes are relied on to manage power system security, instead of the central dispatch process.

As a result, NEMDE would operates unchanged when these reclassifications are in place.

In summary, no change to the central dispatch outcomes seen on 28 September 2016 would have occurred if these new arrangements for reclassification of multiple transmission contingency events under severe weather warnings had been in place on 28 September 2016.

APPENDIX N. WEIGHTED SHORT CIRCUIT RATIO

Conventional calculation methods for determining 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 WSCR, defined by:

$$\mathrm{WSCR} = \frac{\text{Weighted} \quad S_{SCMVA}}{\sum_{i}^{N} P_{RMWi}} = \frac{\left(\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}\right) / \sum_{i}^{N} P_{RMWi}}{\sum_{i}^{N} P_{RMWi}} = \frac{\sum_{i}^{N} S_{SCMVAi} * P_{RMWi}}{\left(\sum_{i}^{N} P_{RMWi}\right)^2}$$

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 SCR at a virtual connection point. However, wind turbine manufacturers specify the minimum permissible SCR 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 region, 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.[133]

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

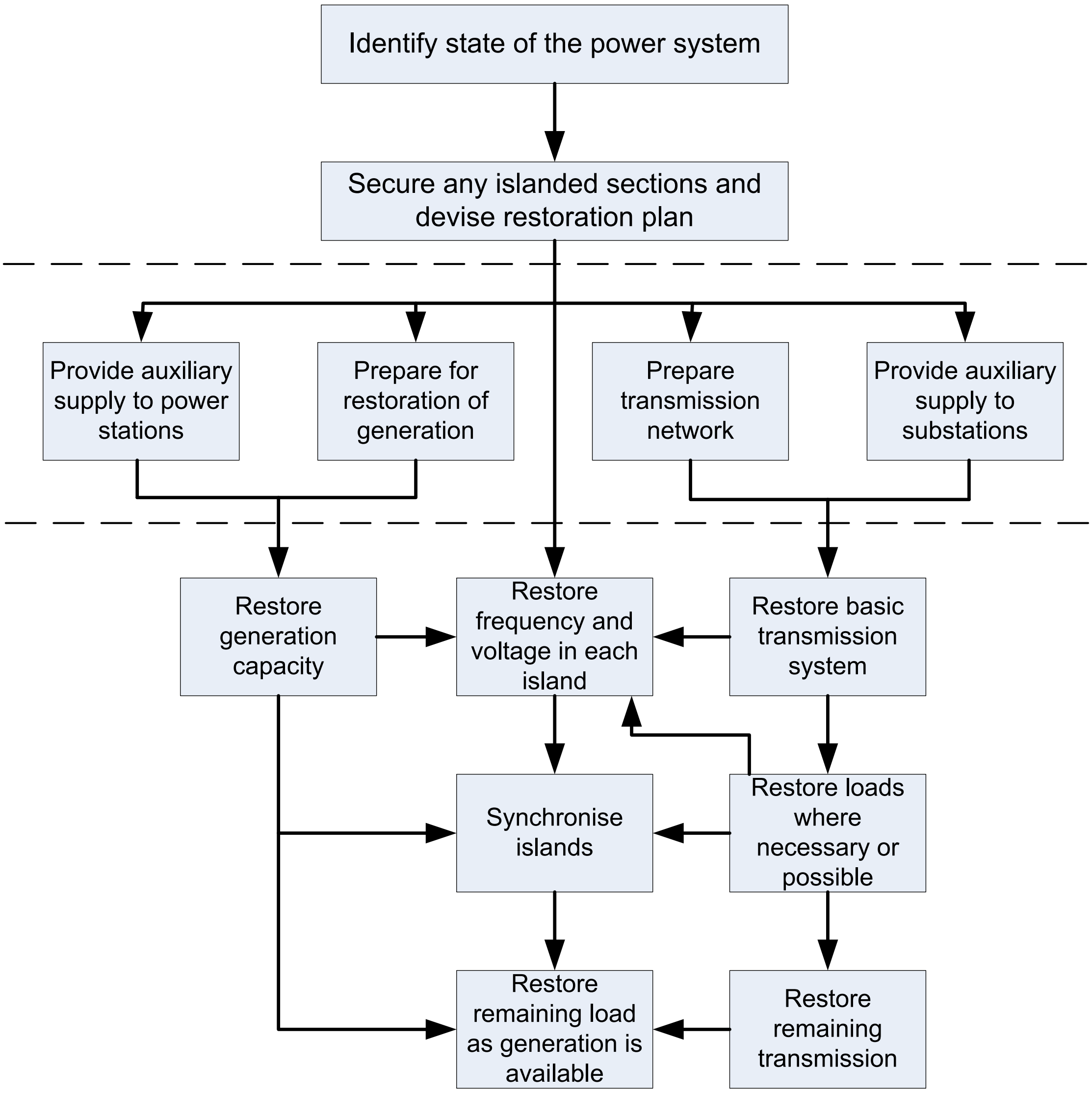
Part of AEMO's due diligence when procuring SRAS is to require the SRAS providers to demonstrate their restart capability in a test prior to entering into an SRAS contract, and then to demonstrate that capability throughout the term of the contract by testing at least annually.

Both of the SRAS procured for SA had been successfully tested less than six months prior to the 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.

[133] 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.[134] 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.

[134] Including generation in other regions via interconnectors.

APPENDIX R. RESTORATION DETAILS

Table 23 Restoration sequence of events – main SA network

Time	Event
28 September	**Initial actions**
16:19 (T+44s)	Confirmed black system condition 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. 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.
19:35 (T+3h 17min)	Happy Valley–Morphett Vale East–Cherry Gardens 275 kV transmission line in service.

Time	Event
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.
18 December 13:18 (T+ 81d)	Davenport–Brinkworth 275 kV line

Table 24 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 112 QPS MW output during restoration

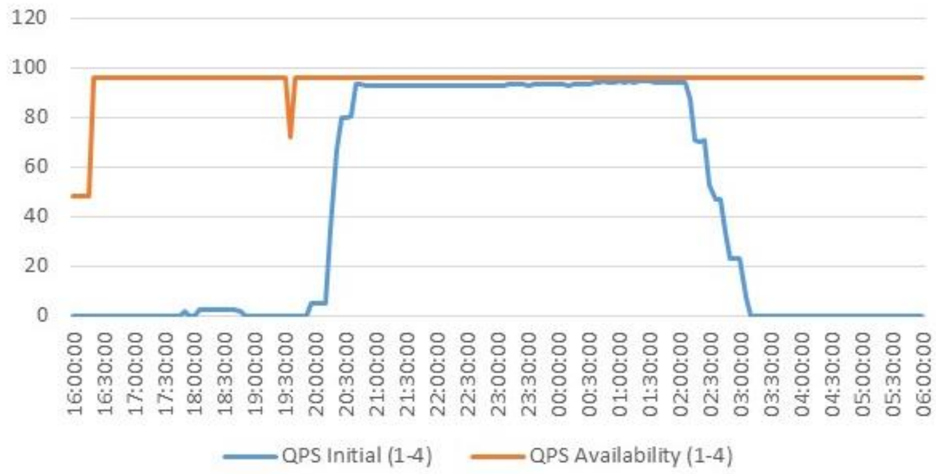


Figure 113 TIPS A2 Generating Unit MW output during restoration

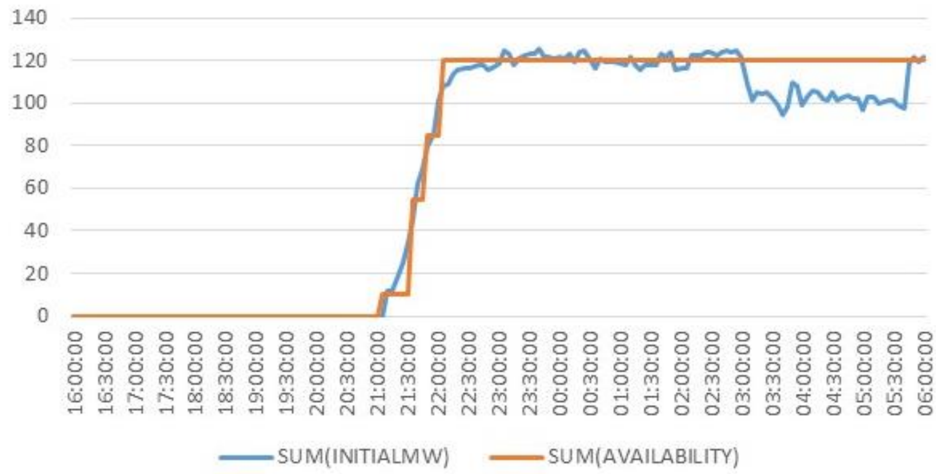


Figure 114 TIPS A4 Generating Unit MW output during restoration

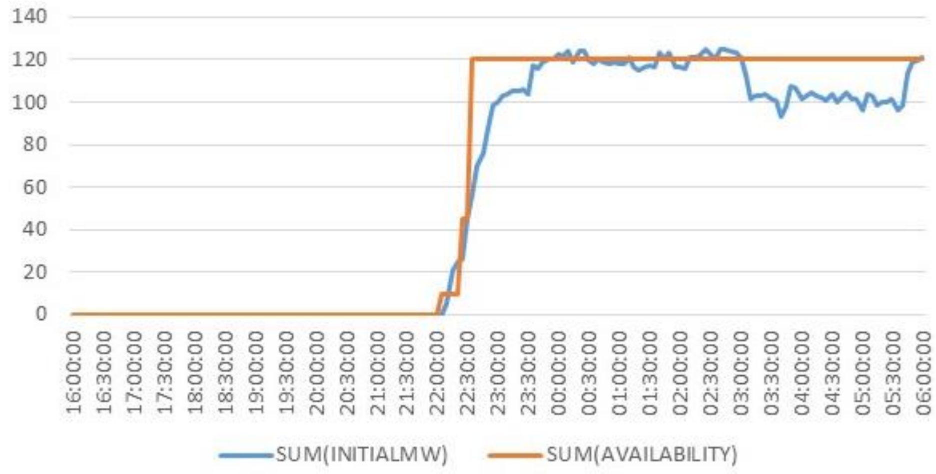
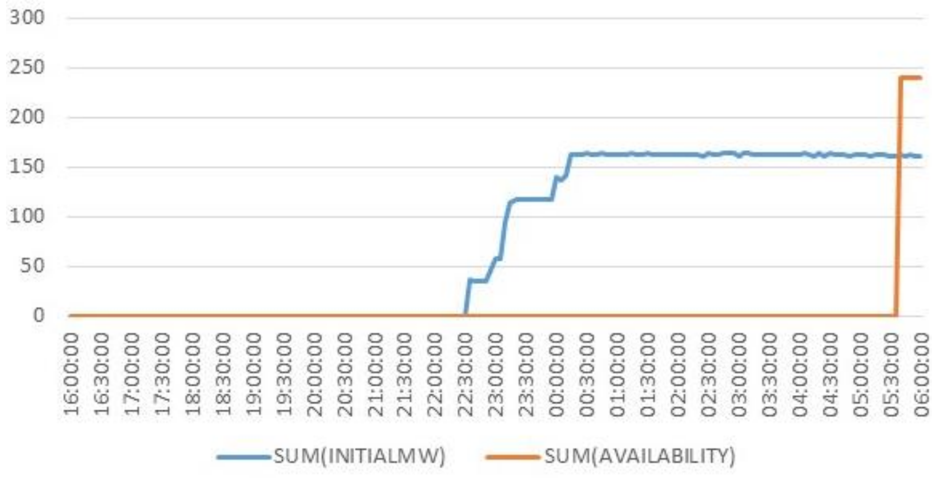


Figure 115 Pelican Point Power Station MW output during restoration



APPENDIX T. MARKET INFORMATION

T.1 AEMO market notices

Below are the market notices issued during the Black System up until "clearance to restore the last load block". Additional Market Notices can be accessed via AEMO's website.[135]

Table 25 AEMO market notices

Date	Time	Action	Summary
28/09/16	16:25	Market Notice 54985 issued –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.	300 MW restored in the SA region.
28/09/16	22:15	Market Notice 55021 issued – Update to SA system black restoration.	700 MW 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.

[135] 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 116 Two hours after the Black System, no load had been restored

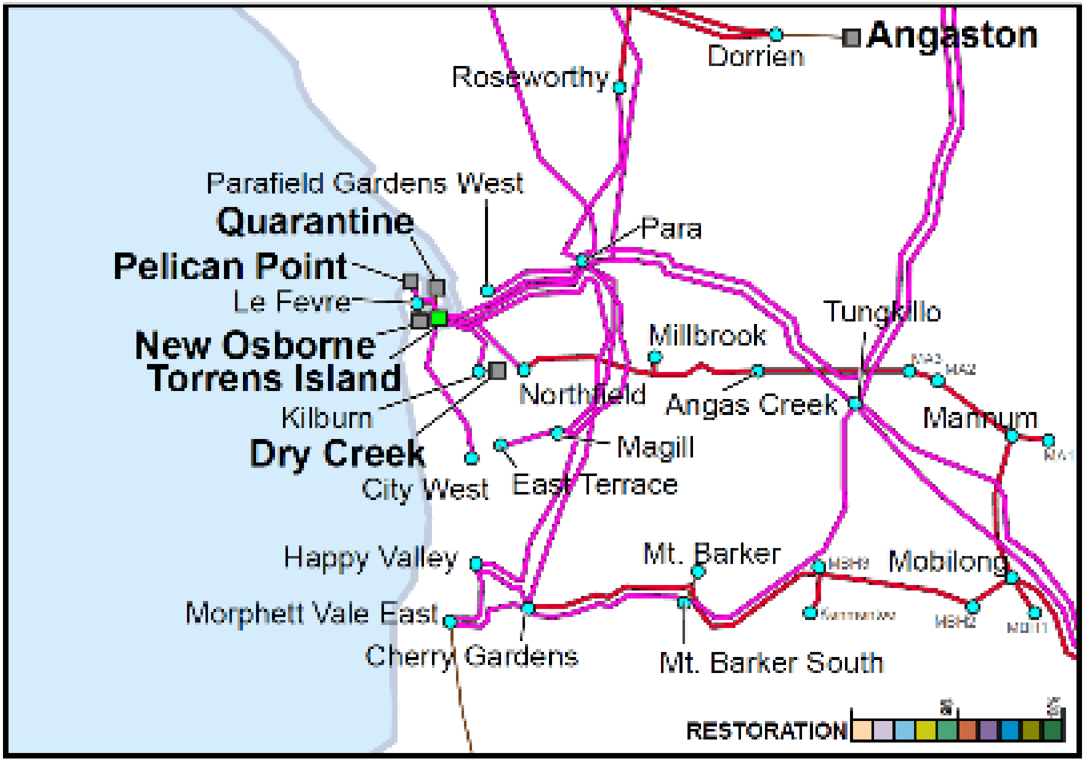


Figure 117 Percentage of load restored after 3 hours

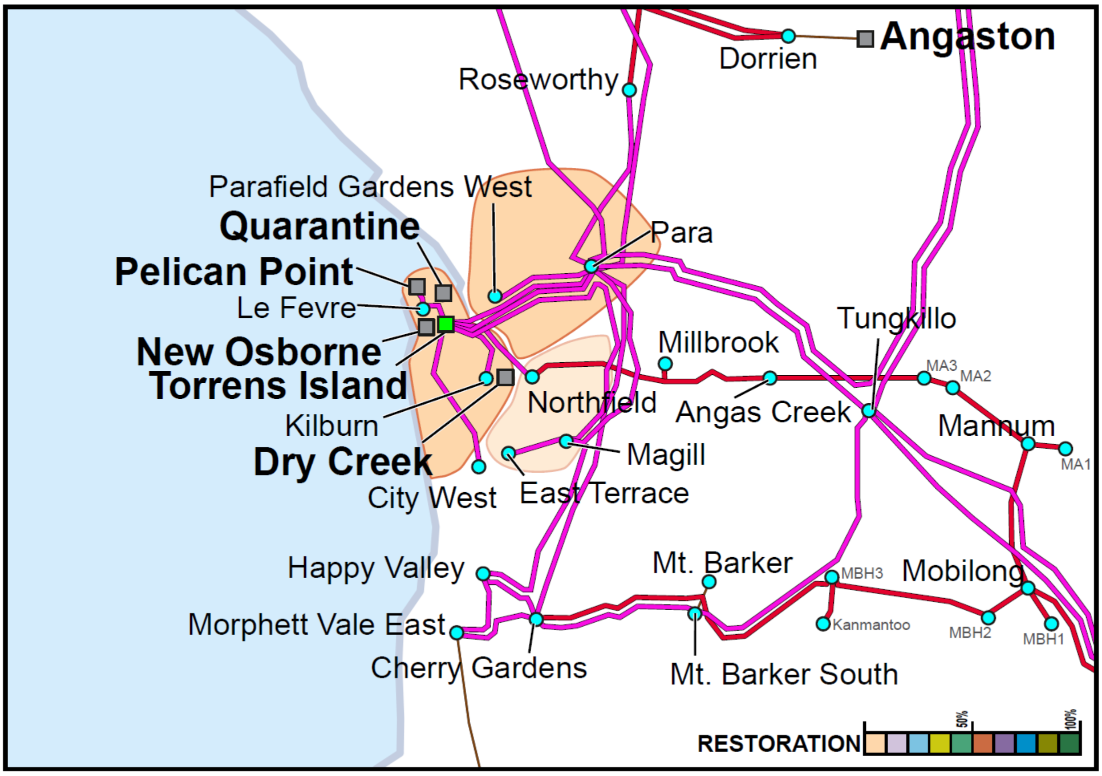


Figure 118 Percentage of load restored after 4 hours

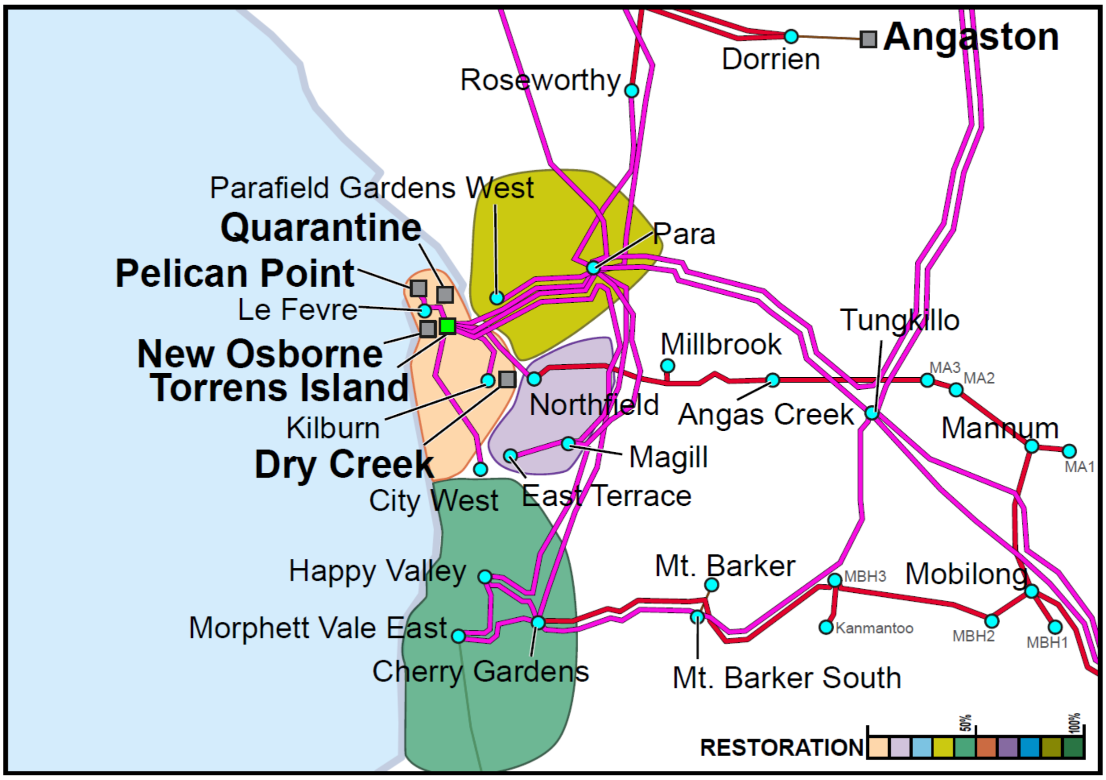


Figure 119 Percentage of load restored after 5 hours

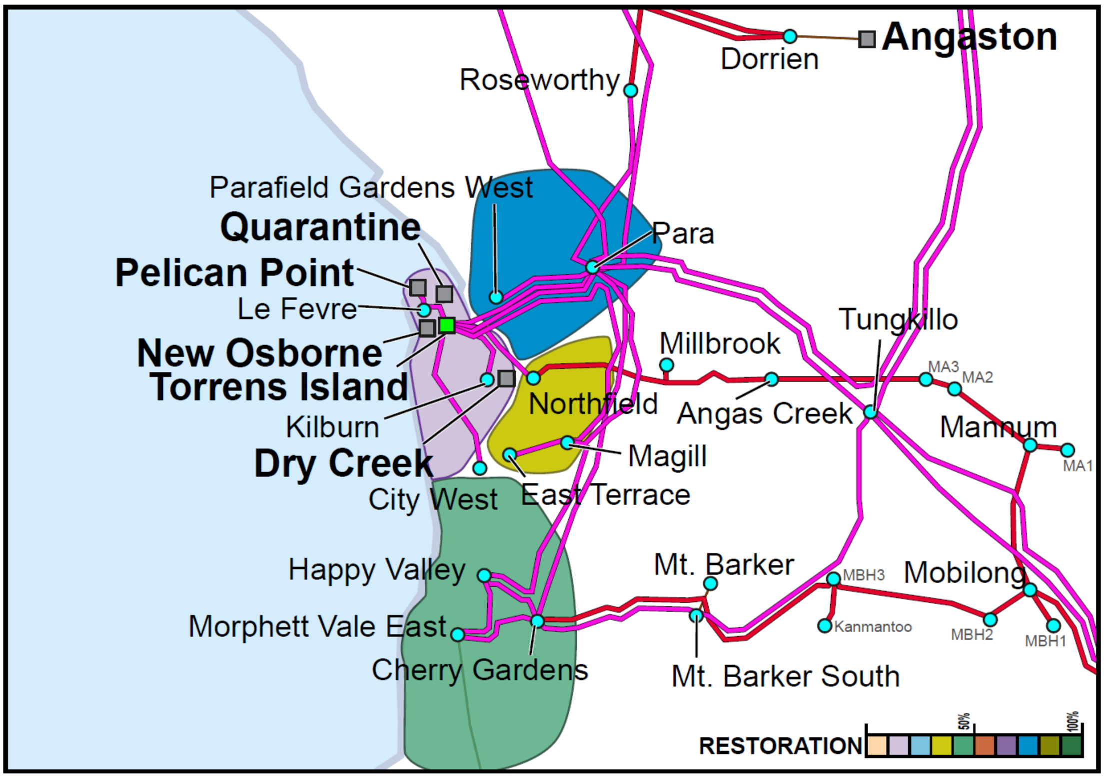


Figure 120 Percentage of load restored after 6 hours

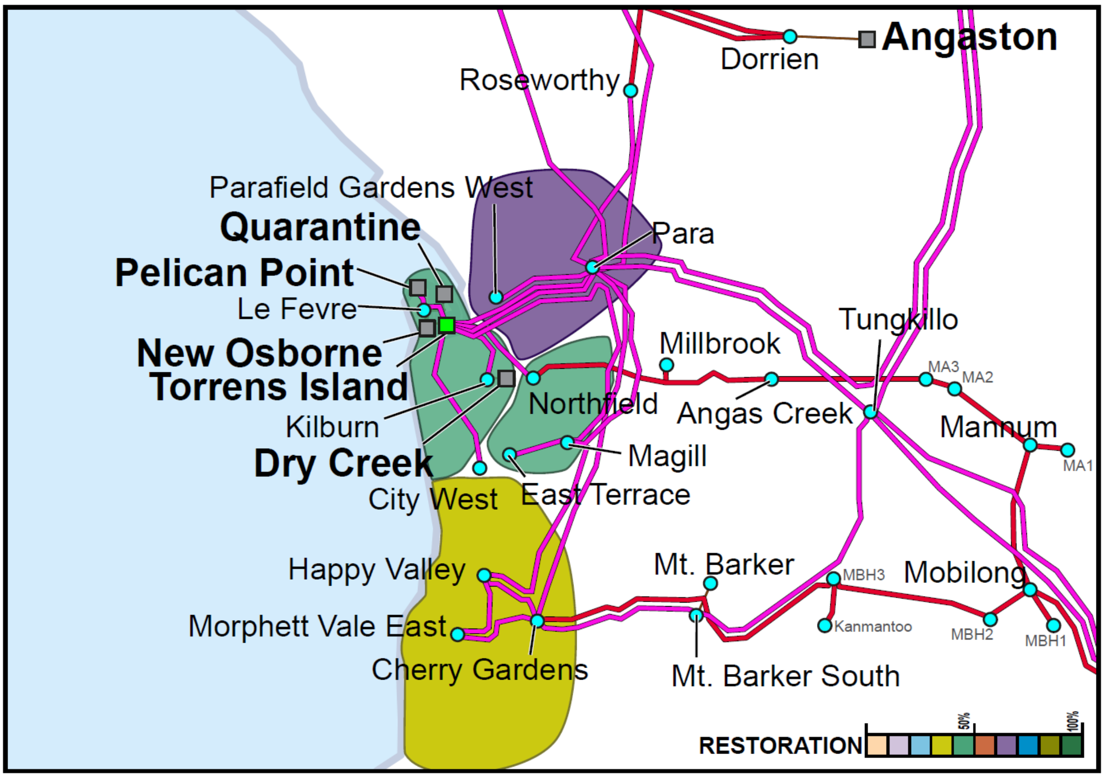
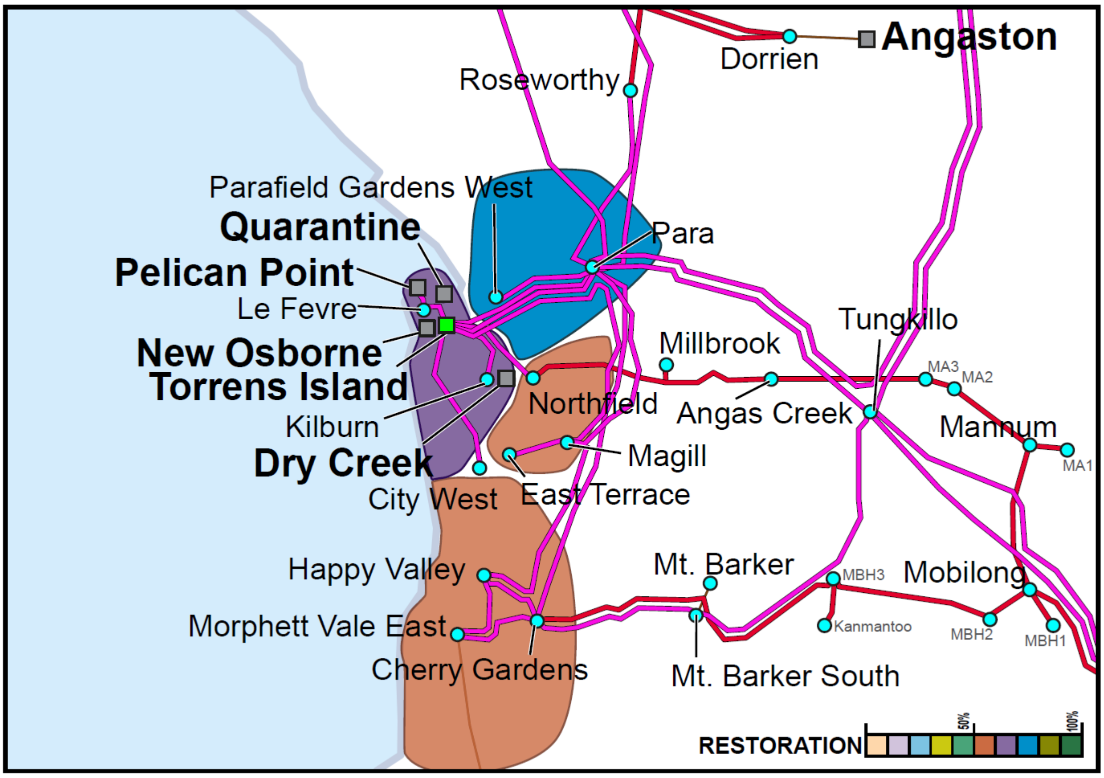


Figure 121 Percentage of load restored after 7 hours



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, 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]
Para–Templers West 275 kV (F1961)*	28.6 m/sec [106 km/h]
Torrens A (TIPS A)–Magill 275 kV (F1912)*	28.6 m/sec [106 km/h]

* This advice has been updated since the publication of the third report.

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.

APPENDIX W. VALIDATION OF POWER SYSTEM SIMULATION MODELS

This Appendix has been added to this final report.

W.1 Summary

This Appendix presents power system modelling and simulation studies assessing the accuracy of the individual wind farms, synchronous generating units, and SVCs in both PSS/E and PSCAD/ETMDC simulation tools. Furthermore, the accuracy of the integrated model of the SA power system comprising all those individual components is evaluated.

The individual plant and overall system models in PSS/E are generally the same as those provided to all Registered Participants, except that adjustments were made to a few individual plant as highlighted in the next section. This is to account for aspects of the plant response not adequately represented in the model, or not represented at all.

To allow a more detailed and accurate assessment of the response of the SA power system under extreme operating conditions, AEMO developed a PSCAD/EMTDC model of the entire SA power system. This includes highly detailed models developed by the OEMs of all Group B and Group D wind farms, and the four SVCs. The PSCAD model used to represent the remainder of the SA power system, including all installed wind farms, is the intellectual property of AEMO.

PSCAD is the most widely used electromagnetic transient (EMT) type simulation tool, and extensively used by a number of major power system equipment manufacturers covering equipment such as wind turbines, solar inverters, HVDC, and FACTS devices. In recent years it has been increasingly used by equipment manufacturers for designing and tuning wind turbines and solar inverters' control systems for connection of wind and solar farms in areas of the NEM with low system strength. The PSCAD permits a full three-phase representation of transmission, distribution, and generation, and the inclusion of fast acting control systems in power electronic converters used in wind turbines. Key advantages of the PSCAD modelling, compared to the PSS/E, are for the following analyses:

- Unbalanced faults.
- Active and reactive power response of the wind turbines during the fault, and recovery after the clearance.
- System strength during islanding conditions.
- System over voltages during islanding conditions.
- Assessment of any SPS to ensure formation of a stable island.

The integrated PSCAD model of the SA power system is the largest and most detailed simulation model of this type developed in Australia to simulate the response of power systems with high penetration of non-synchronous generation.

Despite superior accuracy, a disadvantage of EMT-type simulation tools is the associated computational burden, which inherently limits the number of studies that can be practically undertaken in a reasonable timeframe. For this reason, AEMO has adopted a hybrid approach during this investigation. PSS/E simulations have been used to carry out broad studies, with notable results shortlisted for further investigation and validation in PSCAD.

The Black System has provided AEMO with valuable measured High-Speed Monitor (HSM) data to correlate and validate models against the areas of operation outside of normal limits. This data is rarely captured, and the models have traditionally been considered highly theoretical in application.

W.2 Individual wind farms/synchronous generators/SVCs

W.2.1 Summary

Model validation of individual plant was carried out by segregating each individual model from the rest of the power system, to eliminate external network influences. This approach is referred to as open-loop playback model validation, where the measured voltages and frequencies are injected into the simulation model.

For the PSS/E model validation, the measured positive-sequence root mean square (rms) voltages were injected in the model, whereas in the PSCAD the individual three-phase voltages were injected.

The measured (HSM) values and simulated voltages, and active and reactive power at their respective connection points, were then overlaid (see Figures 123 to 130).

The following key conclusions can be made:

- Models of synchronous generators and SVCs are generally accurate.
- Various degrees of accuracy are observed with the wind farm models. While the more detailed PSCAD models are generally more accurate than the PSS/E models routinely used for large-scale power system studies by AEMO and Registered Participants, AEMO has identified two key factors where actual measured responses differ from the simulations in important ways:
  - The Mt Millar Wind Farm model behaves fundamentally different to actual measured responses. Whereas the simulated response recovers almost instantaneously, in practice, the wind farm takes up to 9 seconds to return to its pre-fault active power level.
  - Across all wind farm models, measured active power responses dip more than the simulated responses during the fault and recover slower following fault clearance.

  The combination of these two factors indicates wind farm model responses led to optimistic transient stability limits being calculated for the Heywood Interconnector. This is discussed further in Appendix X.1. Note that this issue will remain relevant, irrespective of wind farms' capability to ride through a sufficient number of faults in quick succession.
- Sustained power reduction of Group A and B wind farms is not accounted for in any of the simulation models submitted to AEMO. This behaviour was, therefore, manually implemented in the models consistent with the known times of disconnection during the event.

  However, it is noted that with Group A wind farms, disconnection of the actual wind turbines follows a non-linear process, whereby the wind turbines first recover from the fault and disconnect immediately after recovery. Implementing step reductions in a wind farm's active power to emulate an individual wind turbine's disconnection causes minor errors. This is evident from the difference between the measured and simulated response of the transient peaks in active power flow across the Heywood Interconnector following clearance of each fault.
- Simulation models are developed to represent the actual equipment's response, assuming that it behaves as designed. The model cannot replicate the measured response if the actual plant does not behave as designed, such as when a wind farm reduces reactive current injection during the fault, or consumes reactive current during fault conditions. Mismatches between the measured and simulated responses cannot always be considered a modelling deficiency.
- Two prime examples of challenges associated with modelling and simulation of power systems with high penetration of non-synchronous generation can be observed in the response of Waterloo Wind Farm, shown in Figure 129. These errors also cannot be attributed to the simulation model.
  - **PSS/E model**: PSS/E is a positive-sequence simulation platform, responding to the positive-sequence component of the voltage, which is approximately the average of the three-phase voltages. However, wind turbines and dynamic reactive power support devices respond to per-phase measured quantities, which might be very different to the positive-sequence component, especially during unbalanced faults.

In the Waterloo Wind Farm example (Figure 129), the positive-sequence component of the voltage is sufficiently above the 0.85 pu voltage threshold below which fault ride-through mode is activated.

As a result, the PSS/E model does not activate fault ride-through mode for any of the faults leading up to the Black System – unlike the actual wind turbines.

- **PSCAD/EMTDC model**: For wind turbines and dynamic reactive power support devices, certain control actions, such as fault ride-through action, are not analogue in nature, but present more like “switching controllers” with an ‘on/off’ type response, rather than being continuous over time. There is, therefore, a potential for significant non-linearities at the switching threshold.

  For example, in the PSCAD model of the Waterloo Wind Farm (Figure 129), the first fault results in the aggregate wind turbine voltage dropping marginally below 0.85 pu, whereas in the second fault, the wind turbine terminal voltage remains marginally above 0.85 pu.

  The wind farm model, therefore, correctly replicates the actual response for the first fault, but (due to small errors in the order of a fraction of a percent) not the second fault.

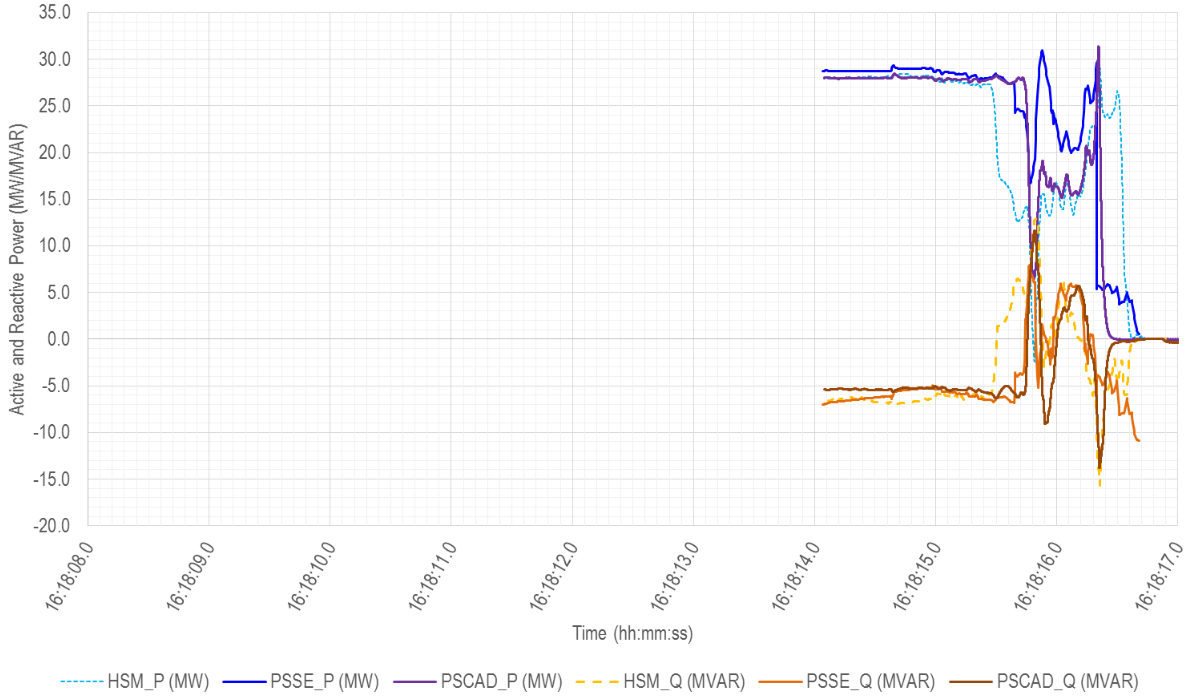
  More accurate representation of the individual wind turbine voltages during fault conditions necessitates explicit representation of each wind turbine and associated impedances. This makes it practically impossible to simulate a large-scale power system comprising several hundreds of wind turbines.

For brevity, representative model overlays are shown. For example, Clements Gap, Hallett, Hallett Hill, The Bluff, and North Brown Hill all use identical wind turbines and dynamic reactive support plant (AMSC’s DVAR). Model overlays are only provided for Hallett Hill and North Brown Hill Wind Farms.

W.2.2 Canunda Wind Farm

Figure 122 shows a good match between PSCAD modelling and measured (HSM) values, but a poorer match between PSS/E modelling and measured values.

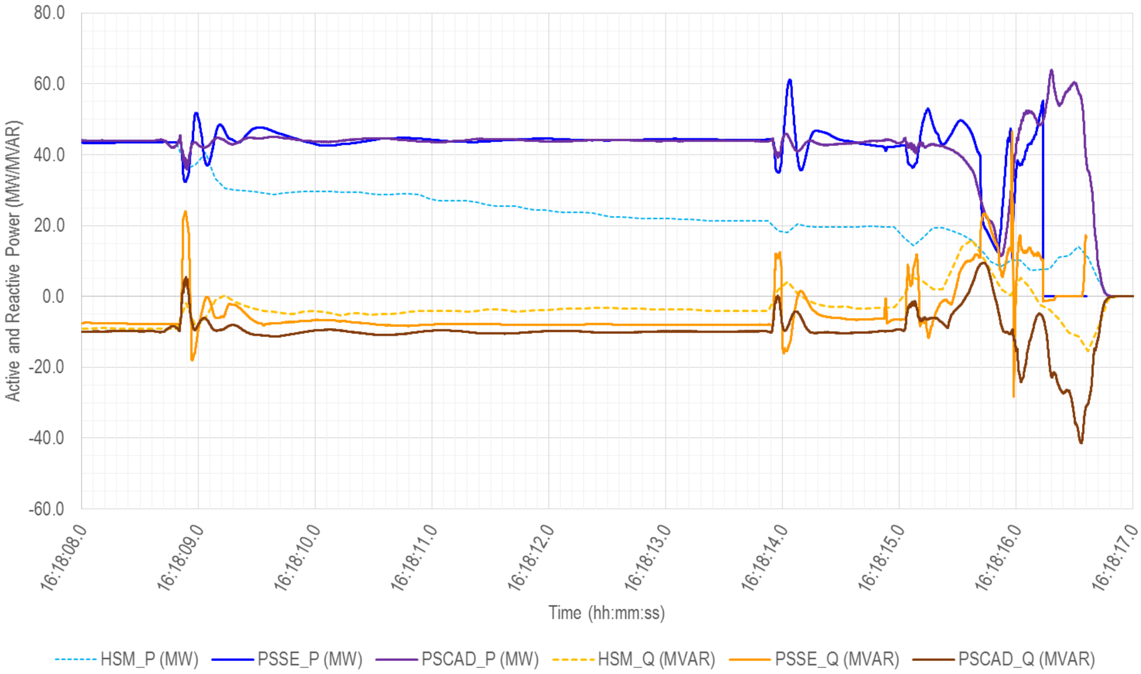
Figure 122 PSS/E And PSCAD simulation of voltage, active power, and reactive power at Canunda Wind Farm’s connection point



W.2.3 Hallett Hill Wind Farm

Figure 123 shows a significant difference between modelled and measured (HSM) active power values, due to the reduction caused in practice by a repeated LVRT alarm which disconnects the wind turbines. This feature is not included in the simulation models provided to AEMO.

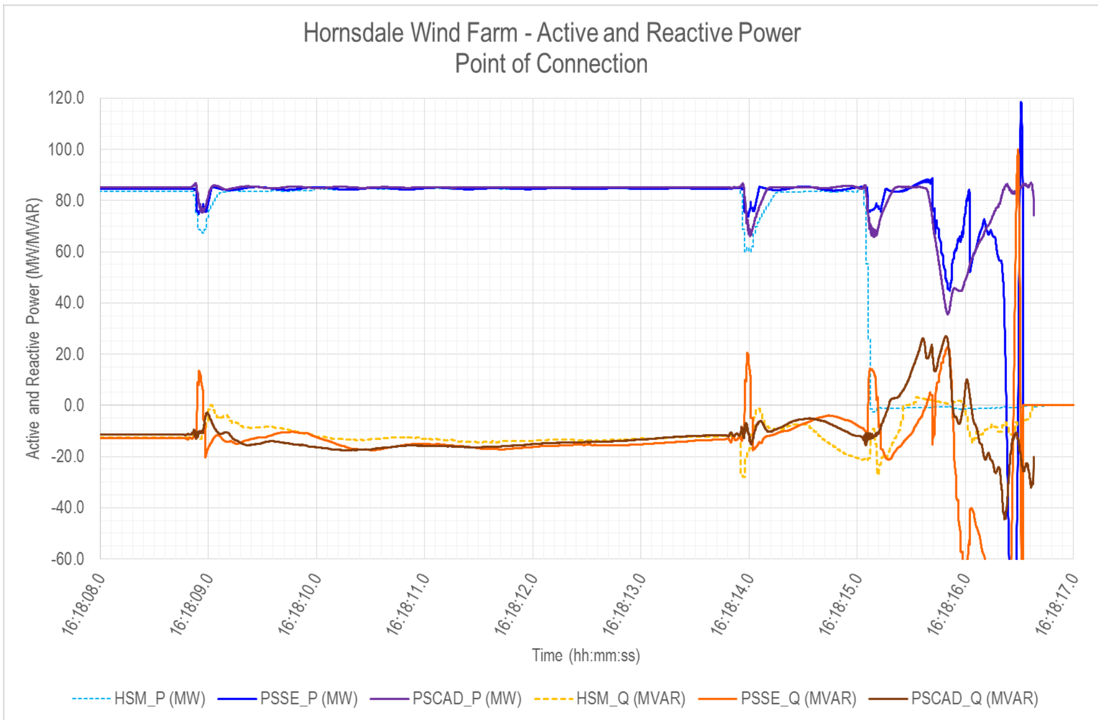
Figure 123 PSS/E and PSCAD simulation of voltage, active power, and reactive power at Hallett Hill Wind Farm's connection point



W.2.4 Hornsdale Wind Farm

Figure 124 shows a significant difference between modelled and measured (HSM) active power values, due to the reduction caused in practice by a repeated LVRT alarm which disconnects the wind turbines. This feature is not included in the simulation models provided to AEMO.

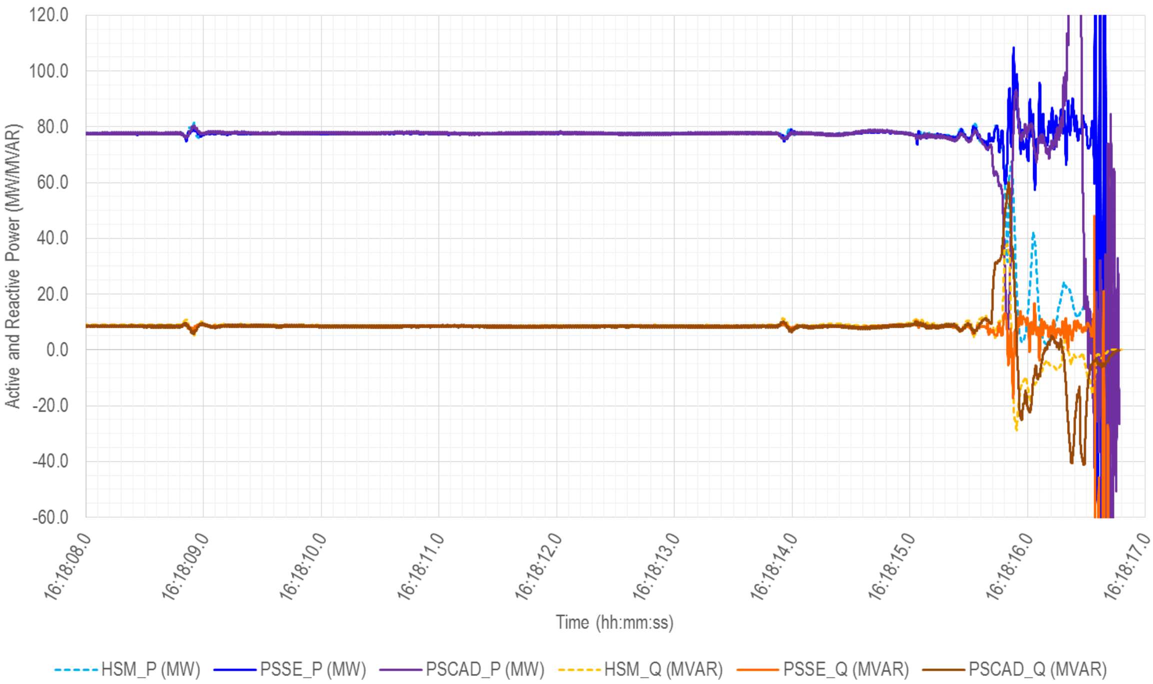
Figure 124 PSS/E and PSCAD simulation of voltage, active power, and reactive power at Hornsdale Wind Farm's connection point



W.2.5 Lake Bonney 1 Wind Farm

Figure 125 shows a good match between PSCAD and PSS/E modelling and measured (HSM) values up to final collapse.

Figure 125 PSS/E and PSCAD simulation of voltage, active power, and reactive power at Lake Bonney 1 Wind Farm's connection point

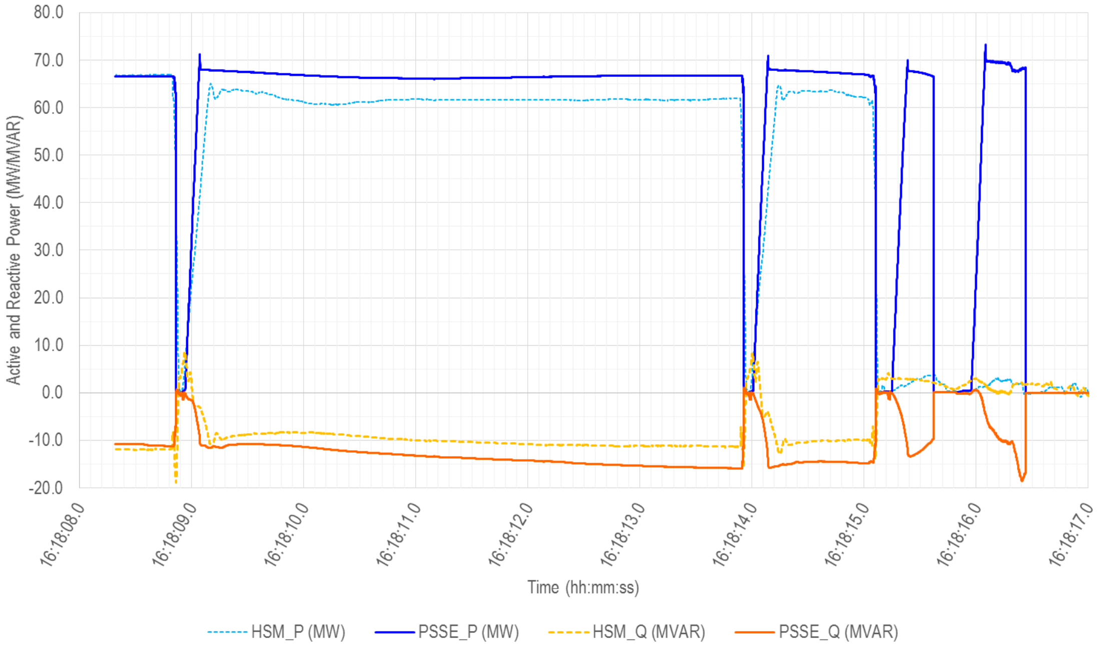


W.2.6 Mt Millar Wind Farm

Figure 126 shows a good match between PSCAD and PSS/E modelling and measured (HSM) values up to 16:18:15. After that time, PSS/E modelling outcomes for active power differ considerably from measured values, due to the absence of zero power mode of operation in the simulation model.

A PSCAD model of this turbine type was not made available to AEMO. Such a model would not have necessarily improved the model accuracy, unless it accounted for the zero power mode feature.

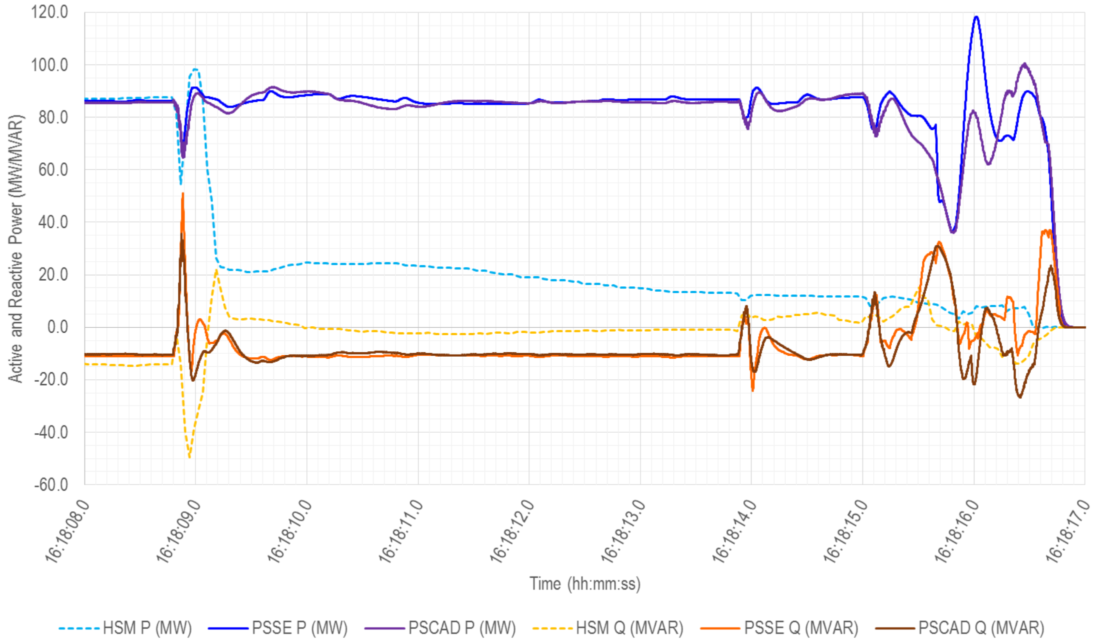
Figure 126 PSS/E simulation of voltage, active power, and reactive power at Mt Millar Wind Farm's connection point



W.2.7 North Brown Hill Wind Farm

Figure 127 shows a significant difference between modelled and measured (HSM) active power values, due to the reduction caused in practice by a repeated LVRT alarm which disconnects the wind turbines. This feature is not included in the simulation models provided to AEMO.

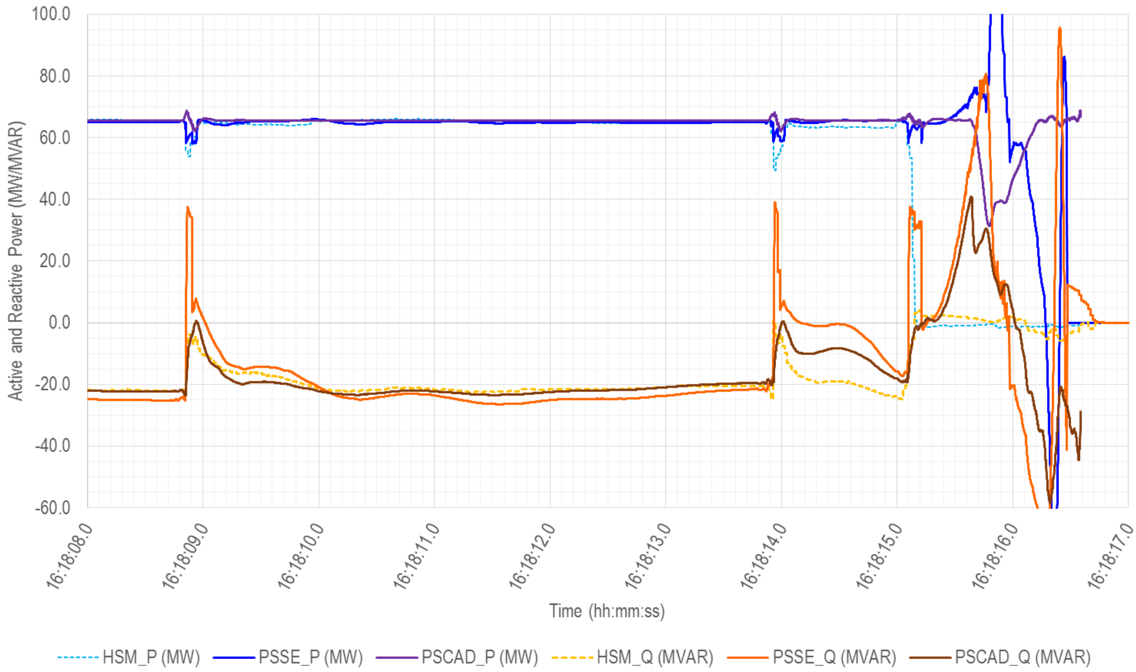
Figure 127 PSS/E and PSCAD simulation of voltage, active and reactive power at North Brown Hill Wind Farm's connection point



W.2.8 Snowtown South Wind Farm

Figure 128 shows a significant difference between modelled and measured (HSM) active power values, due to the reduction caused in practice by a repeated LVRT alarm which disconnects the wind turbines. This feature is not included in the simulation models provided to AEMO.

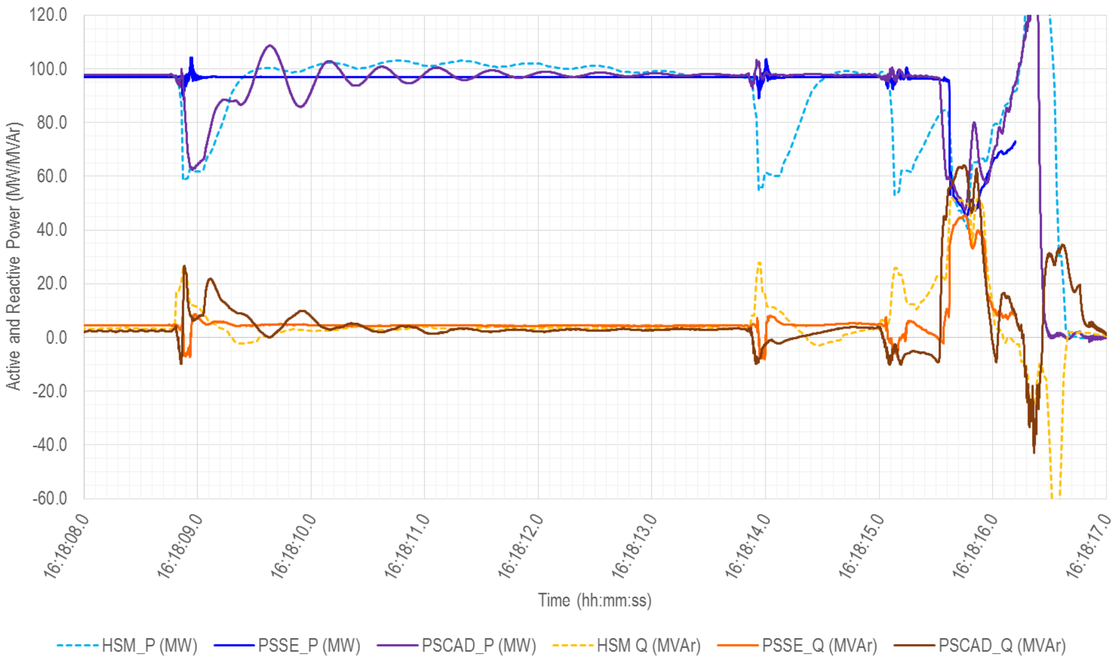
Figure 128 PSS/E and PSCAD simulation of voltage, active and reactive power at Snowtown South Wind Farm's connection point



W.2.9 Waterloo Wind Farm

Figure 129 shows significant differences between modelled and measured (HSM) values at 16:18:14 and 16:18:15, due to modelling of trigger point for LVRT mode (for more detail, see Appendix W.1).

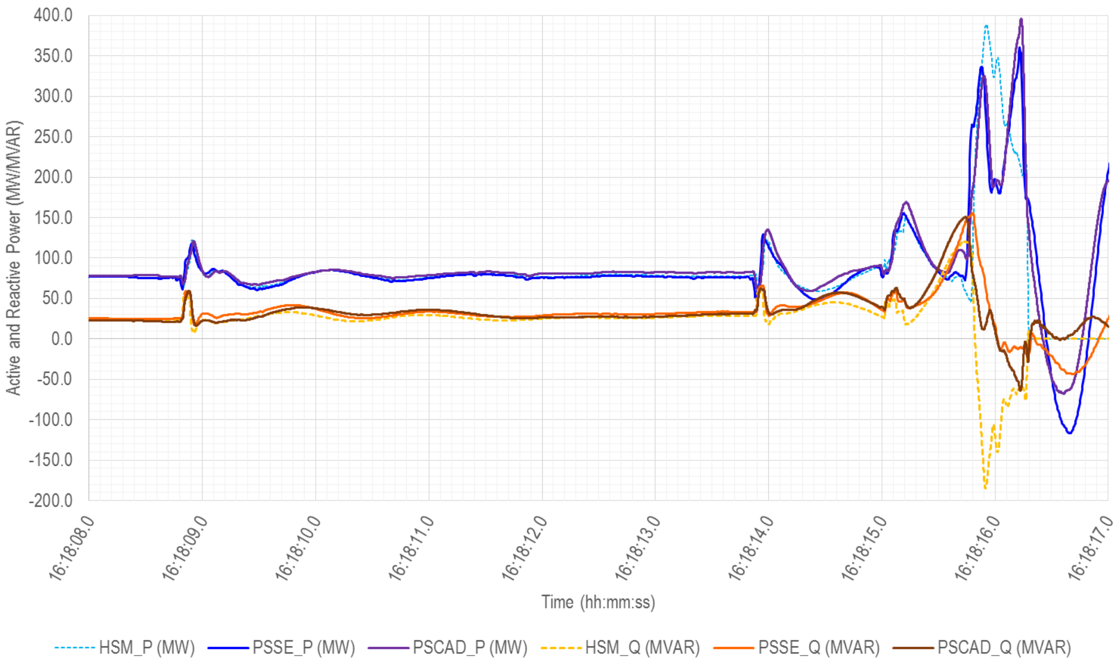
Figure 129 PSS/E and PSCAD simulation of voltage, active power, and reactive power at Waterloo Wind Farm's connection point



W.2.10 TIPS B4

Figure 131 shows a good match between PSCAD and PSS/E modelling and measured (HSM) values up to final collapse.

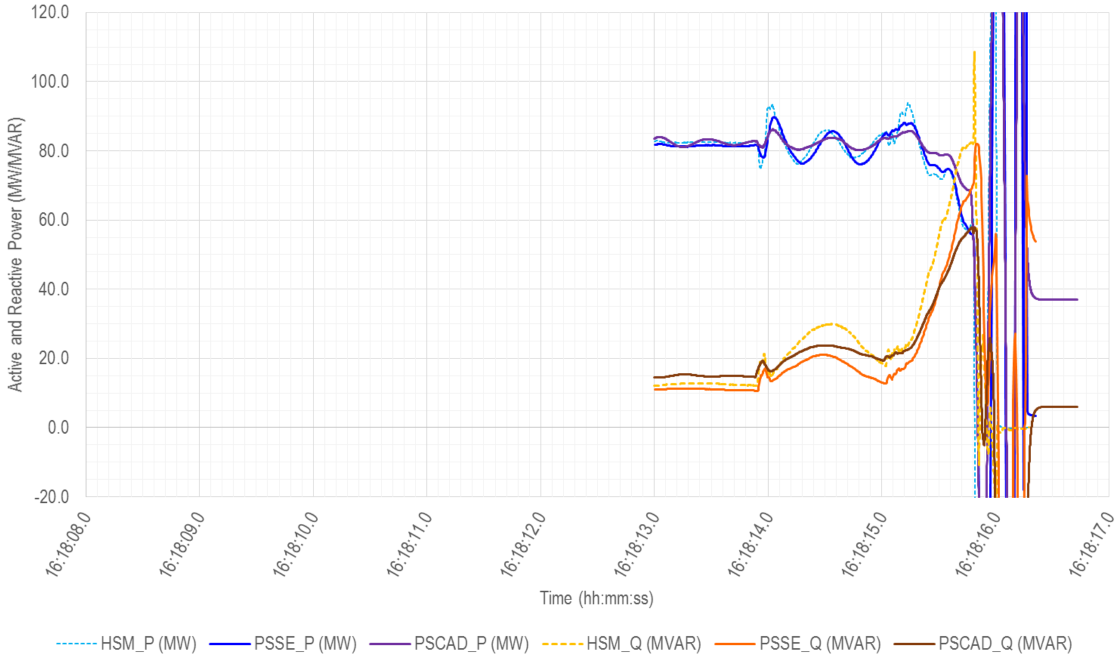
Figure 130 PSS/E and PSCAD simulation of voltage, active power, and reactive power at TIPS B4 connection point



W.2.11 Ladbroke Grove units

Figure 131 shows a good match between PSCAD and PSS/E modelling and measured (HSM) values up to 16:18:16.

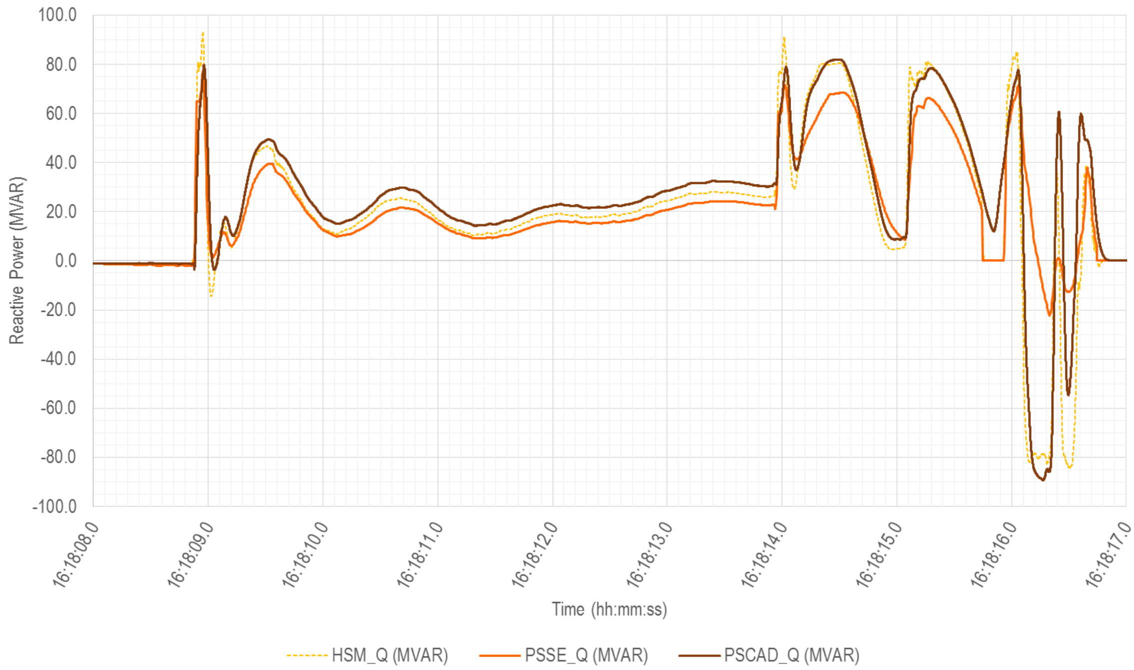
Figure 131 PSS/E and PSCAD simulation of voltage, active power, and reactive power at Ladbroke Grove connection point



W.2.12 Para SVC 2

Figure 132 shows a good match between PSCAD and PSS/E modelling and measured (HSM) values up to final collapse.

Figure 132 PSS/E and PSCAD simulation of three-phase voltages and reactive power at Para SVC2



W.3 Overall SA power system

W.3.1 Introduction

To gain confidence in the veracity of simulation results, and the observations/conclusions that have followed, AEMO has benchmarked the integrated simulation model representing the SA transmission and distribution network and all SA generating units against field measurements for the system incident from ElectraNet and Generators.

AEMO's primary objective was to demonstrate that the transmission network faults leading to the Black System can be recreated by simulation. This provides confidence in veracity of these modelling tools for predicting the power system response for any given 'what if' scenario analysis.

To assess the accuracy of the simulations, the following benchmarking criteria were established, using the PSS/E and PSCAD/EMTDC simulation tool:

- Active and reactive power flow at Heywood Interconnector.
- System voltage magnitudes at key 275 kV substations, in particular the South East Substation.
- Relative voltage phase angles at the key 275 kV substation with reference to Heywood Terminal Station's voltage phase angle.
- Impedance trajectory seen by the Heywood loss of synchronism relay.
- Frequencies at key 275 kV substations.

The detailed results from the benchmarking studies are presented in Appendices W.3.2 and W.3.3.

These show that the PSS/E and PSCAD models used for event analysis could accurately recreate the key phenomena. Most critically, they could recreate the combination of rapidly changing currents and voltages across the Heywood Interconnector, which determine whether a loss of synchronism and subsequent islanding would occur.

Note that minor differences exist between the PSS/E and PSCAD impedance trajectories after they enter the inner blinder of loss of synchronism relay. This is because, with PSS/E, it is not possible to continue the simulation run after the Heywood Interconnector opens. PSCAD simulation studies can, however, be successfully run several hundred ms after the islanding.

The sharp knee point in the impedance trajectory that occurs after the islanding conditions is observable in the PSCAD results but not the PSS/E. This does not, however, have any impact on accuracy of the PSS/E results, as the loss of synchronism is inevitable as soon as the impedance trajectory crosses the inner blinder of the relay.

Based on the results obtained, AEMO concludes that for the overall power system simulation:

- PSCAD results are more accurate than the PSS/E.
- The SA power system models developed in both the PSS/E and PSCAD (including modifications applied to a few models) are sufficiently accurate to confidently analyse the sequence of events (despite inaccuracies in some of the individual models).

The use of these models is also appropriate for analysing issue of SA system stability following credible and non-credible loss of generation in the SA power system.

It must be recognised that simulation tools in general show susceptibility to abrupt changes in RoCoF (which also means abrupt changes in the voltage phase angles). For this reason, simulated frequencies in the PSS/E or PSCAD may not be reliable at the time of system separation. However, this has no implications on the conclusions reached, because system frequencies at the time of separation are not used in this report to draw any conclusions.

Due to the absence of multiple fault ride-through settings in wind farm models provided to AEMO, Group A and B wind farms were manually disconnected at known fault times in the simulation models to emulate the sustained power reduction experienced during the event.

Figures 134 to 147 show the comparison of measured and simulated responses of the Heywood Interconnector in terms of voltage, active power, and reactive power.

Both PSCAD and PSS/E results indicate correct and intended operation of LOS relay. Figure 136 shows system voltage phase angles that confirm a genuine loss of synchronism did occur, and relay operated correctly.

W.3.2 PSS/E simulation

Figure 133 shows a good match between the simulated and measured (HSM) responses, with some minor inaccuracies in peak active and reactive power flow after each voltage disturbance.

Figure 133 Active and reactive power transfer at Heywood Interconnector

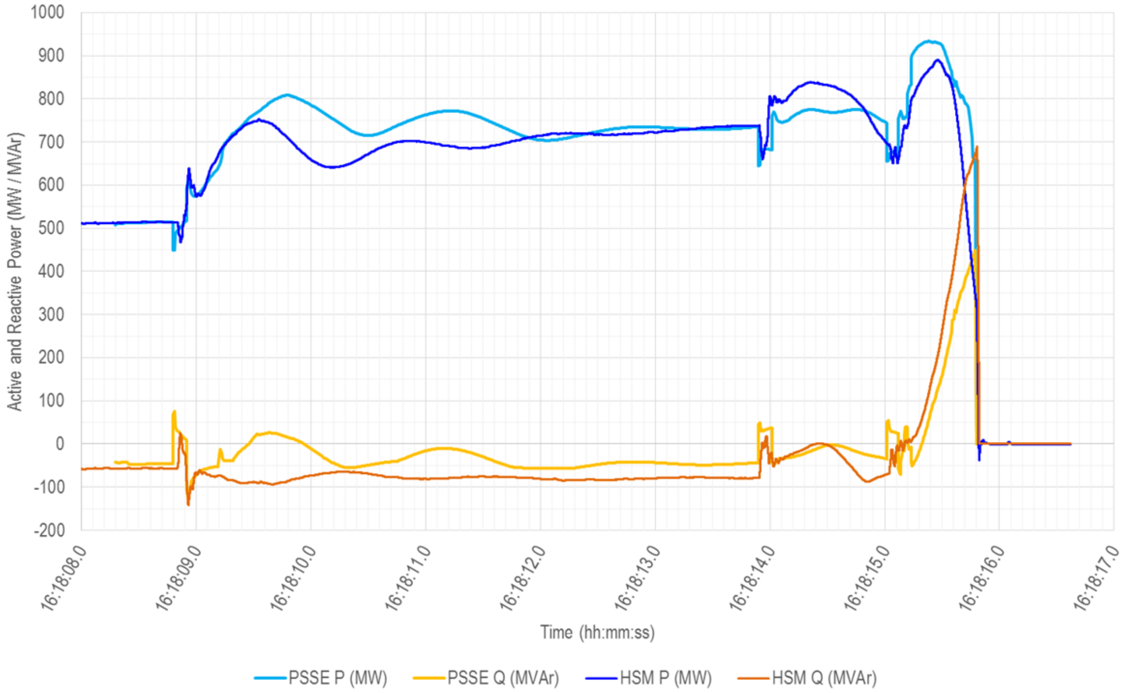


Figure 134 shows a good match between modelling and measured (HSM) values, with insignificant errors in simulating voltages at the time of system separation. This difference will have no impact on the ability to predict conditions resulting in loss of synchronism and whether a viable island can be formed.

Figure 134 Voltage magnitudes at key SA 275 kV substations

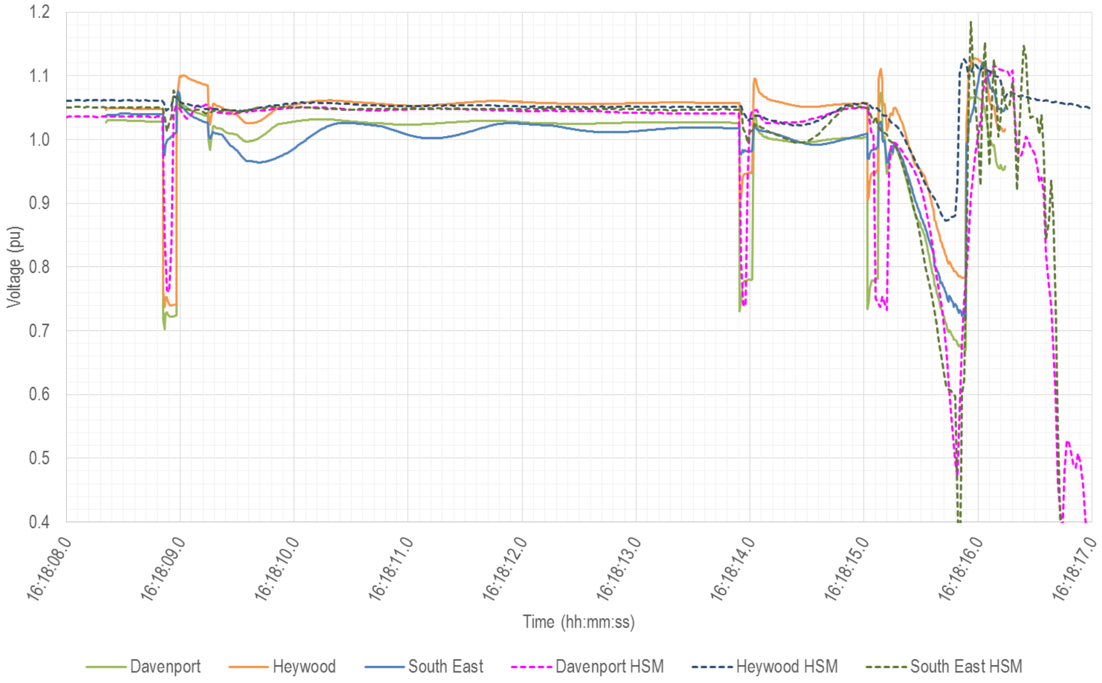


Figure 135 shows a good match between the measured and simulated response of impedance trajectory seen by Heywood LOS relay. Note that the PSS/E impedance trajectory stops earlier than the measured response, because it is not possible to continue the PSS/E dynamic simulation run once the system is separated.

Figure 135 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

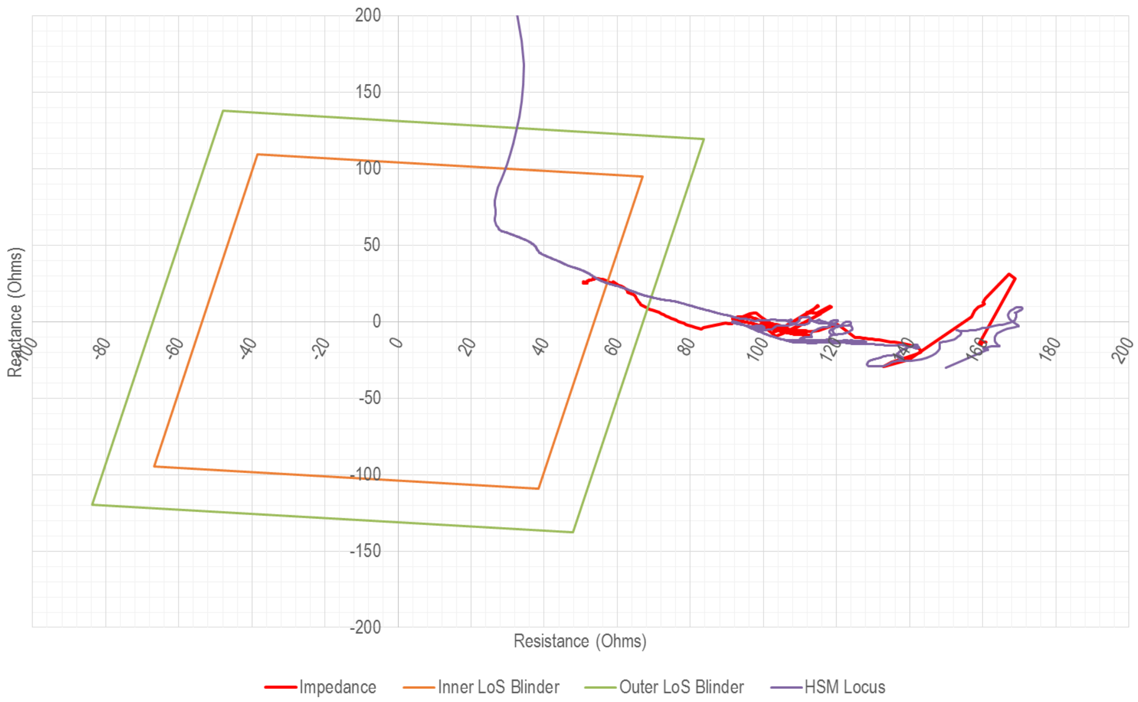
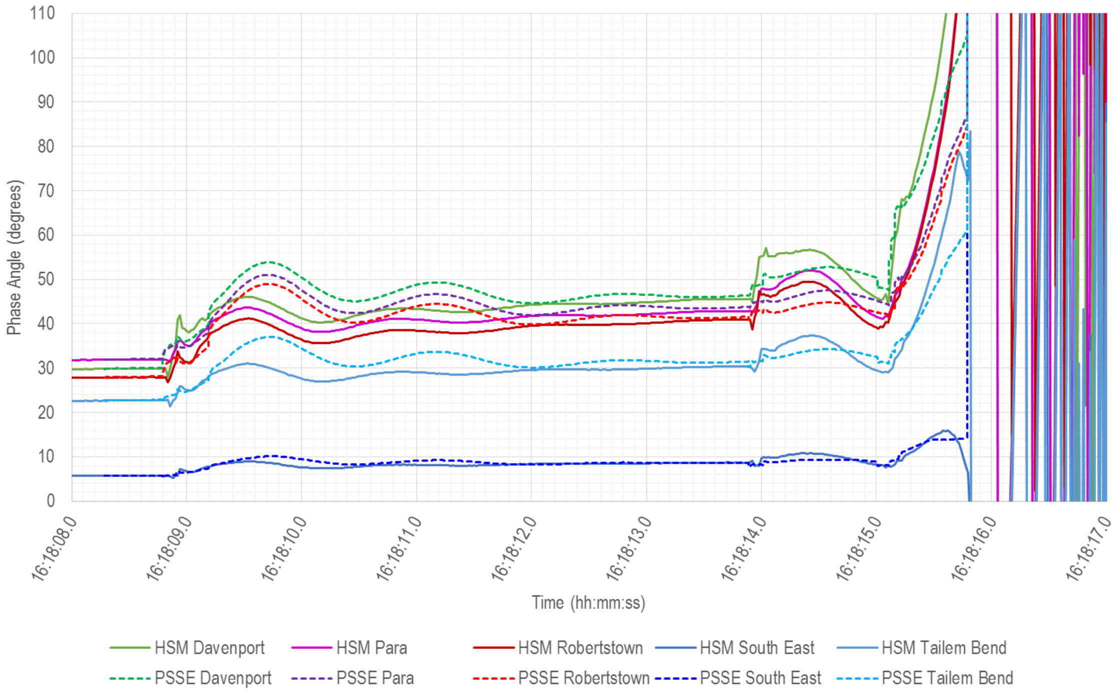


Figure 136 shows a good match between the measured and simulated response of the voltage phase angles up to the point of separation. From this point, all voltage phase angles swing rapidly between -

180 and 180 degrees, due to the overall system's loss of synchronism. Voltage phase angle does not therefore have any practical significance in the last few hundred ms after system separation.

Figure 136 Voltage phase angles relative to HYTS at key SA 275 kV substations



In Figure 137, differences can be observed between the modelled and measured (HSM) values of the Davenport frequency. This stems from the inability of the PSS/E and most other simulation tools to calculate the frequency under extreme operating conditions with abrupt changes in both voltage and frequency. This difference has no material impact on predicting whether loss of synchronism and islanding conditions will occur.

Figure 137 Frequencies at key SA 275 kV substations

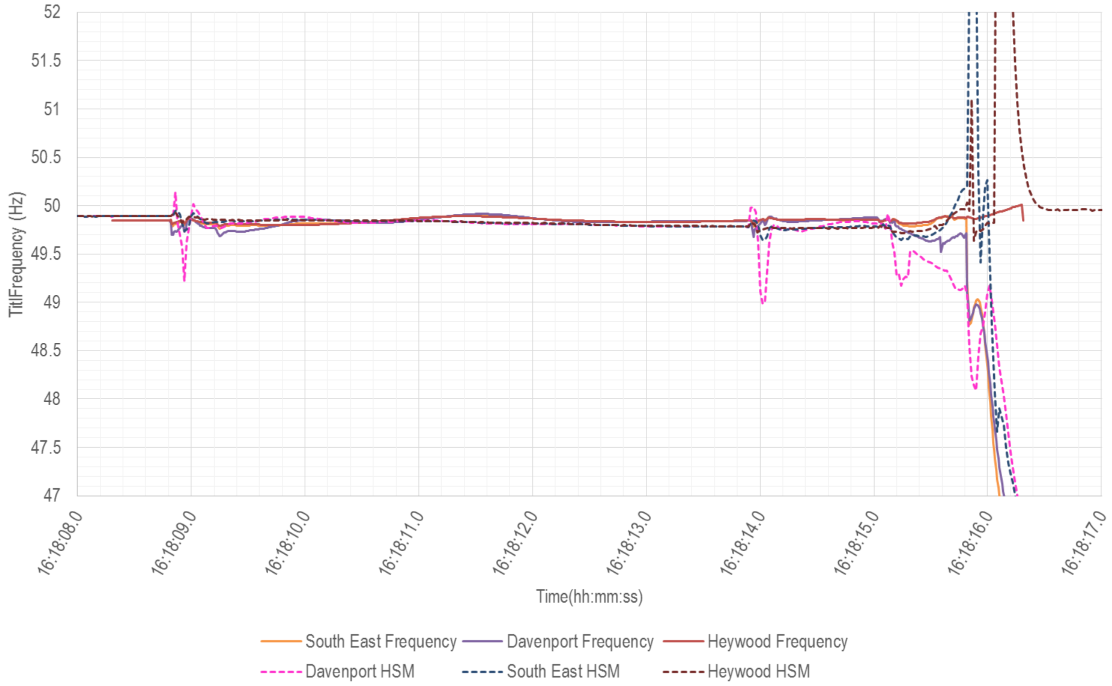
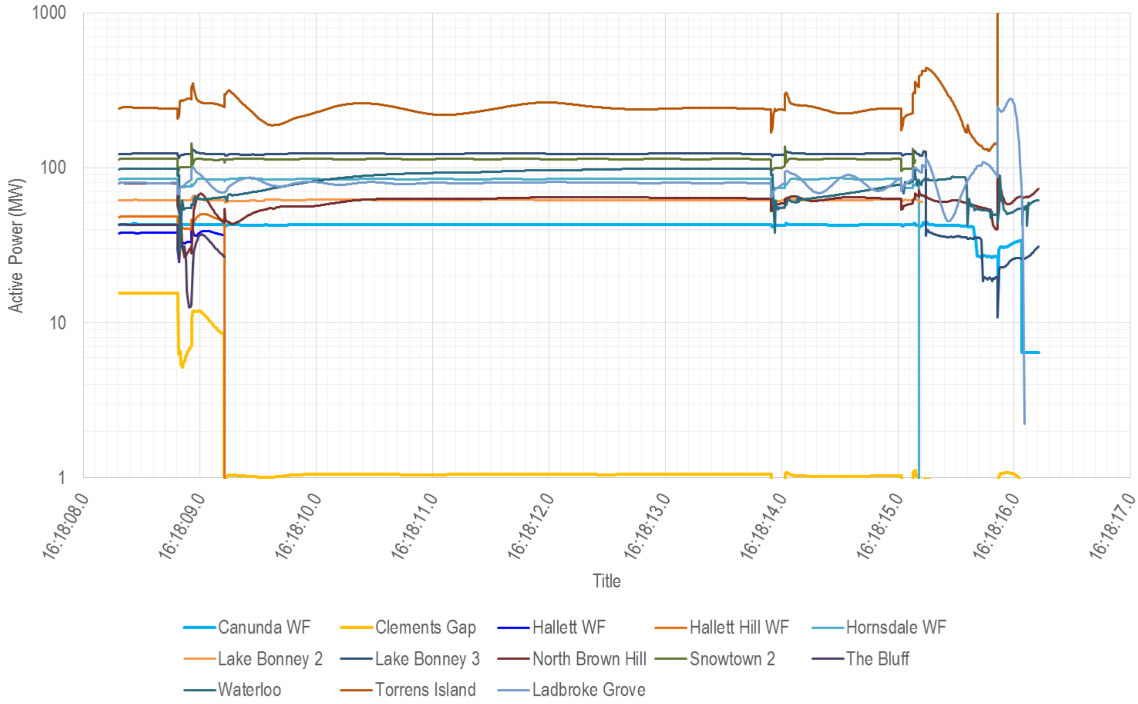


Figure 138 Individual active power output



The measured values for generator active power are shown in Appendix I. Comparisons of measured and simulated response of each generating system are presented in Figure 122 to Figure 131. Note that PSS/E dynamic simulation could not be continued after 16:18:16, due to inability of the dynamic simulation solver to deal with rapidly changing dynamics.

W.3.3 PSCAD simulation

Figure 139 shows a good match between modelling and measured (HSM) values, with an insignificant mismatch in reactive power flow immediately before system separation. This difference has no material impact on predicting whether loss of synchronism and islanding conditions will occur, as this is determined by the impedance trajectory (shown in Figure 140). Comparing Figure 139 and Figure 133 indicates more accurate simulation of peak values of active and reactive power flows in PSCAD immediately after the clearance of each voltage disturbance.

Figure 139 Active and reactive power transfer at Heywood Interconnector

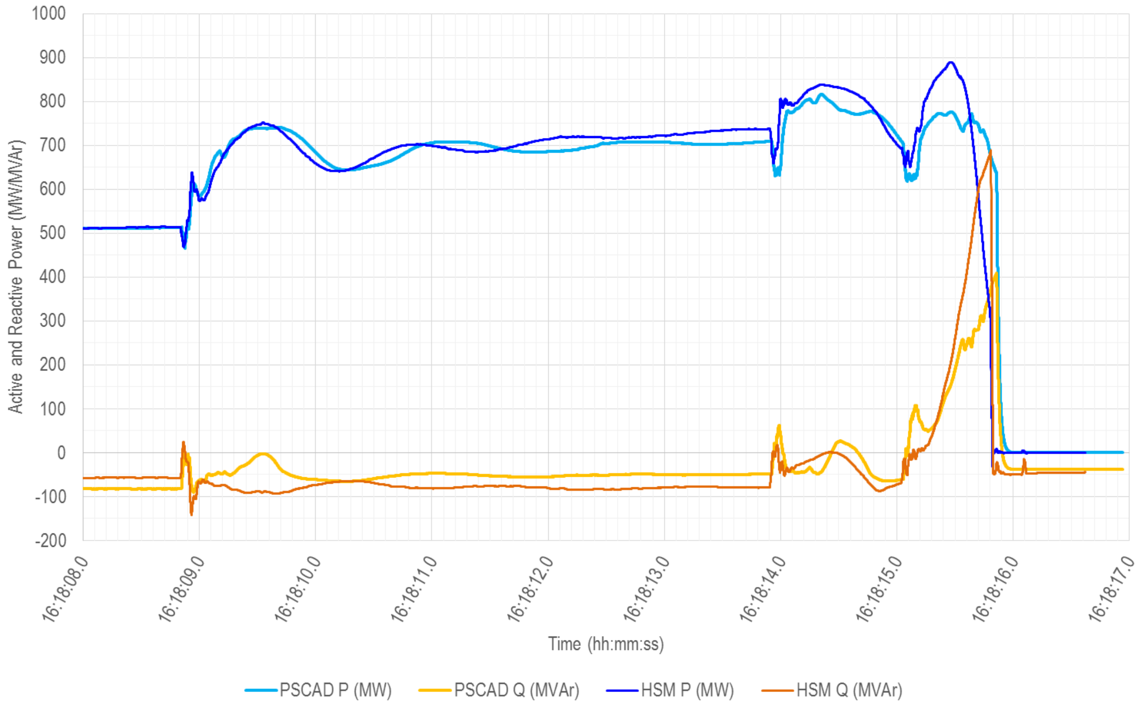


Figure 140 shows a good match between modelling and measured (HSM) values where both the measured and simulated impedance trajectories enter the inner blinder of the Heywood LOS relay, confirming correct and intended operation of this relay.

Figure 140 PSCAD impedance trajectory at Heywood Interconnector against relay characteristic area

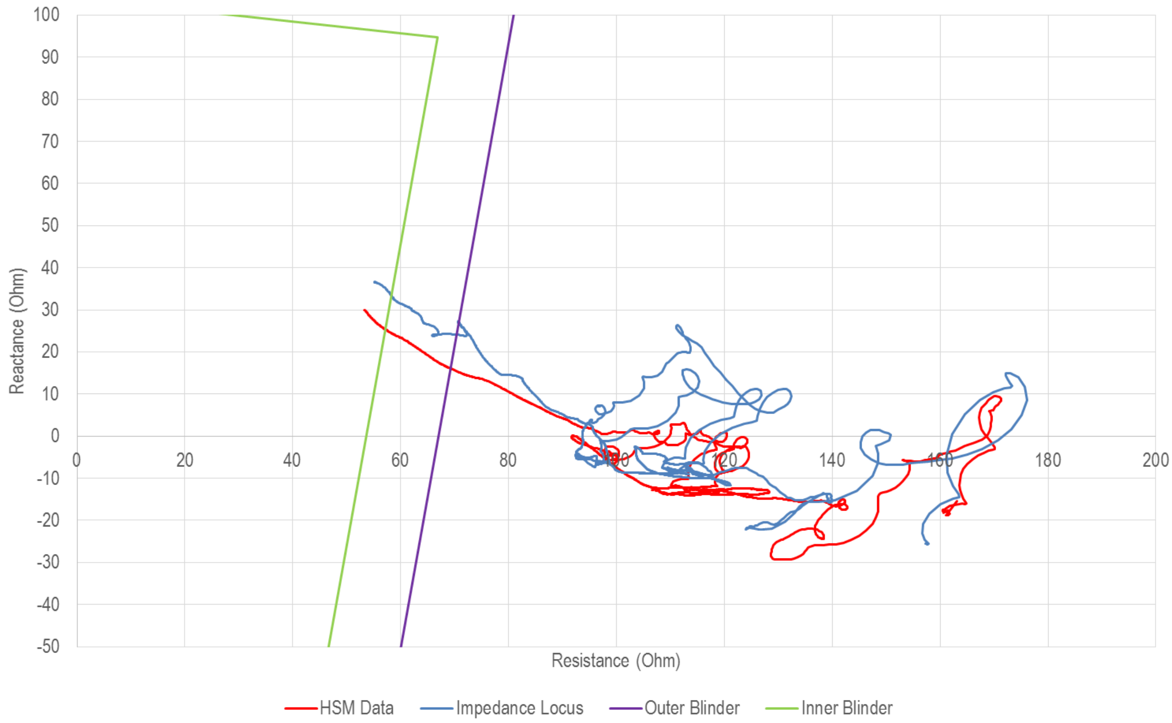


Figure 141 shows a good match between modelling and measured (HSM) values up to the point of system separation.

Figure 141 Voltage magnitudes at key SA 275 kV substations

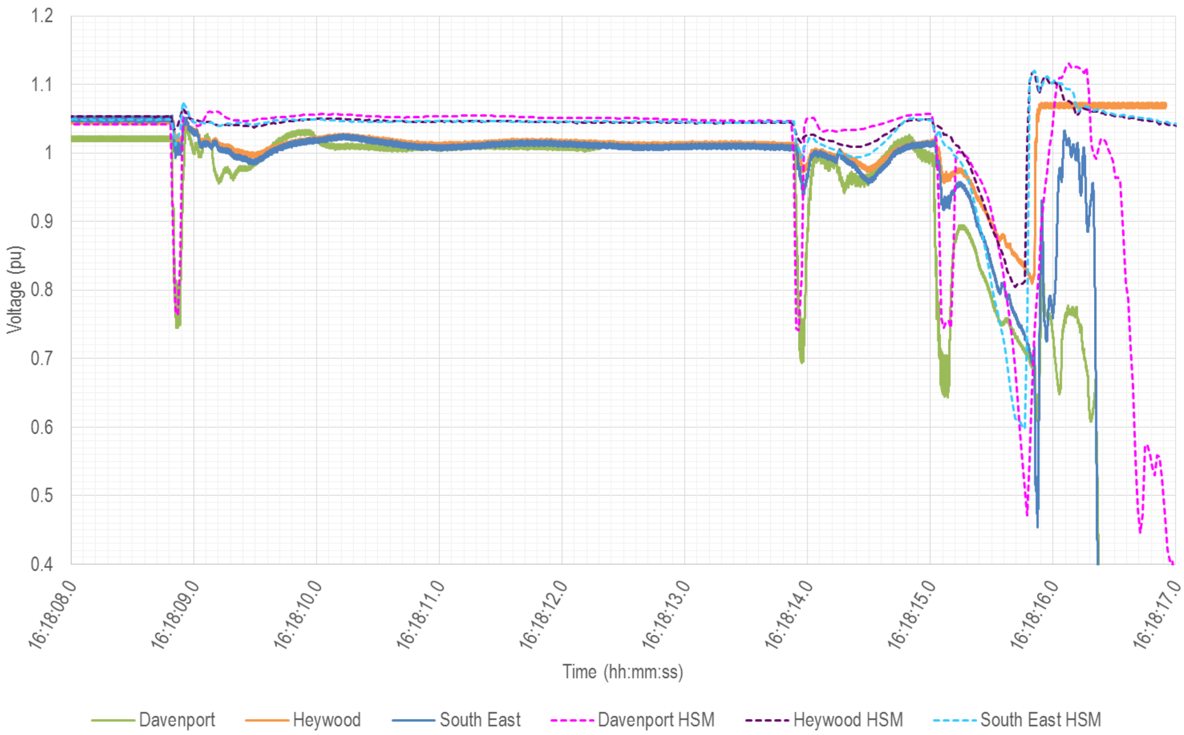


Figure 142 shows a good match between the measured and simulated response of the voltage phase angles up to the point of separation. Comparing Figure 142 and Figure 136 indicates that the peak voltage phase angles at 16:18:09 and 16:18:14 are more accurately represented in the PSCAD than in the PSS/E.

Figure 142 Voltage phase angles relative to HYTS at key SA 275 kV substations

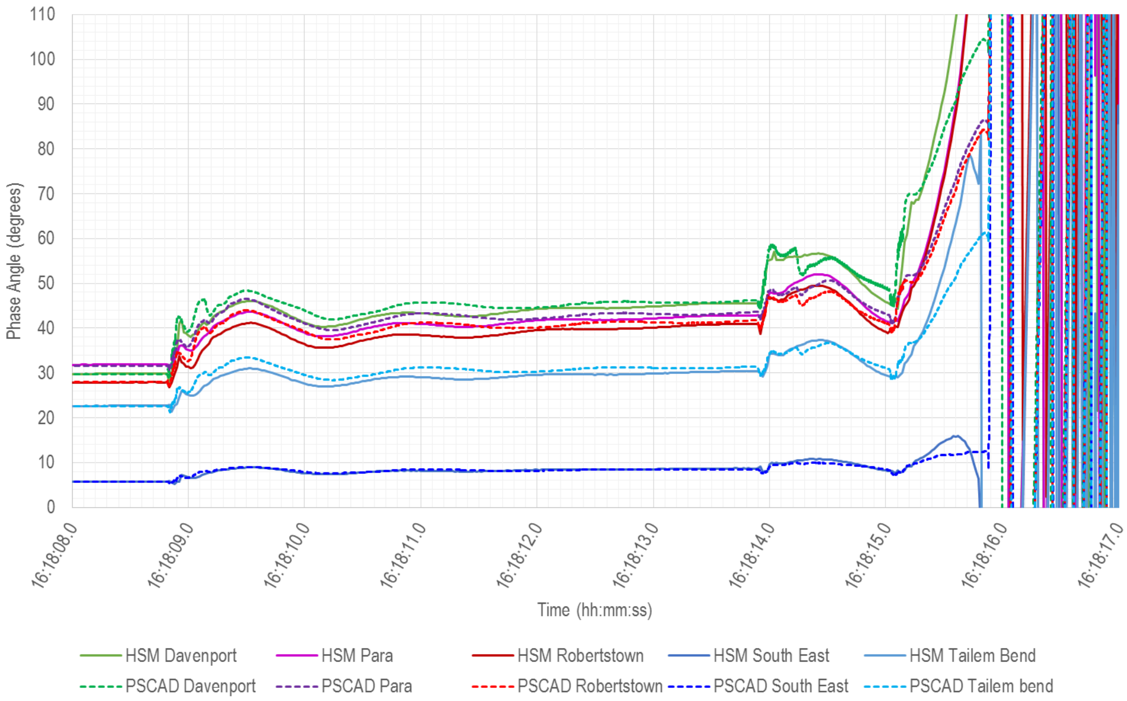


Figure 143 shows mismatches between the measured and simulated frequency for each of the three voltage disturbances. However, this is not relevant to predicting whether loss of synchronism and islanding conditions will occur. The reason for this inaccuracy has been already discussed in Appendix W.3.1 and W.3.2.

Comparing Figure 143 and Figure 137 it can be seen that, unlike the PSS/E which shows smaller frequency nadirs than the measured vales for the three voltage disturbances, corresponding PSCAD results indicate larger nadirs than the measured responses. This difference stems from different approaches used by the PSS/E and PSCAD for calculating the frequency.

Figure 144 depicts responses of individual generating systems. Unlike the PSS/E, the PSCAD dynamic studies can be successfully run up to 16:18:17. The measured values for generator active power are shown in Appendix I. Comparisons of the measured and simulated response of each generating system are presented in Figure 122 to Figure 131.

Figure 143 Frequencies at key SA 275 kV substations

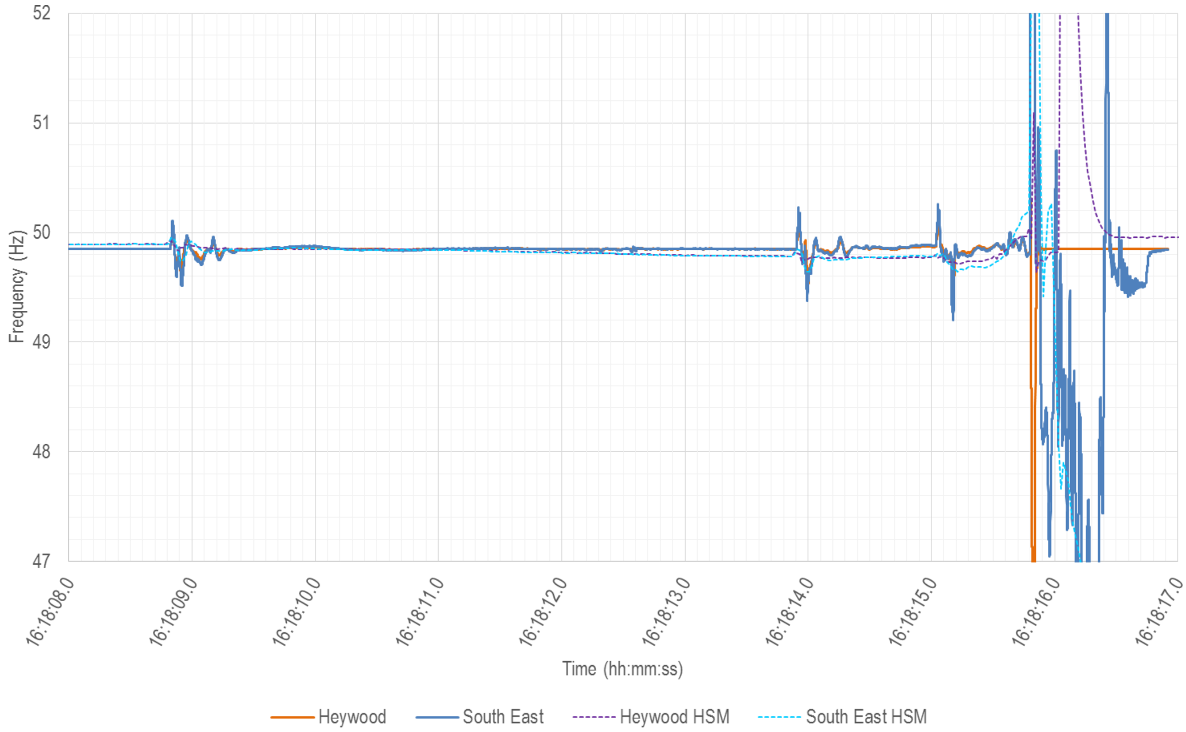
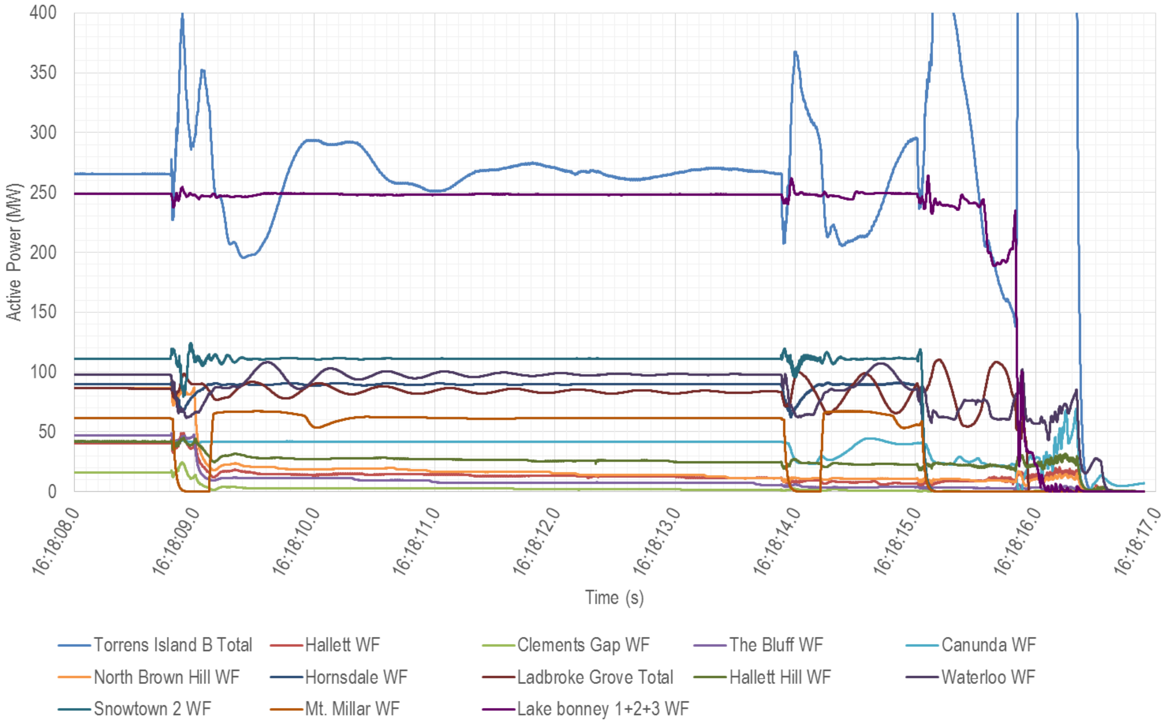


Figure 144 Individual generators' active power



The measured values for generator active power are shown in Appendix I. Comparisons of the measured and simulated response of each generating system are presented in Figure 122 to Figure 131.

W.4 Comparison of PSS/E and PSCAD simulation models

Figure 145 shows a good match between modelling and measured (HSM) values up to separation.

The model performance post separation is not relevant to predicting whether loss of synchronism and islanding conditions will occur. Note that PSS/E simulation stops immediately after system separation, due to the inability of the dynamic solution engine to deal with rapid and substantial changes in voltages and frequencies. A sharp peak of 1.25 pu is observable in the PSCAD response immediately after the separation. The actual measured response exhibits smaller over voltages, likely to be due to over voltage clamping behaviour of network transformers in the saturated region.

Figure 145 Voltages at Heywood Interconnector

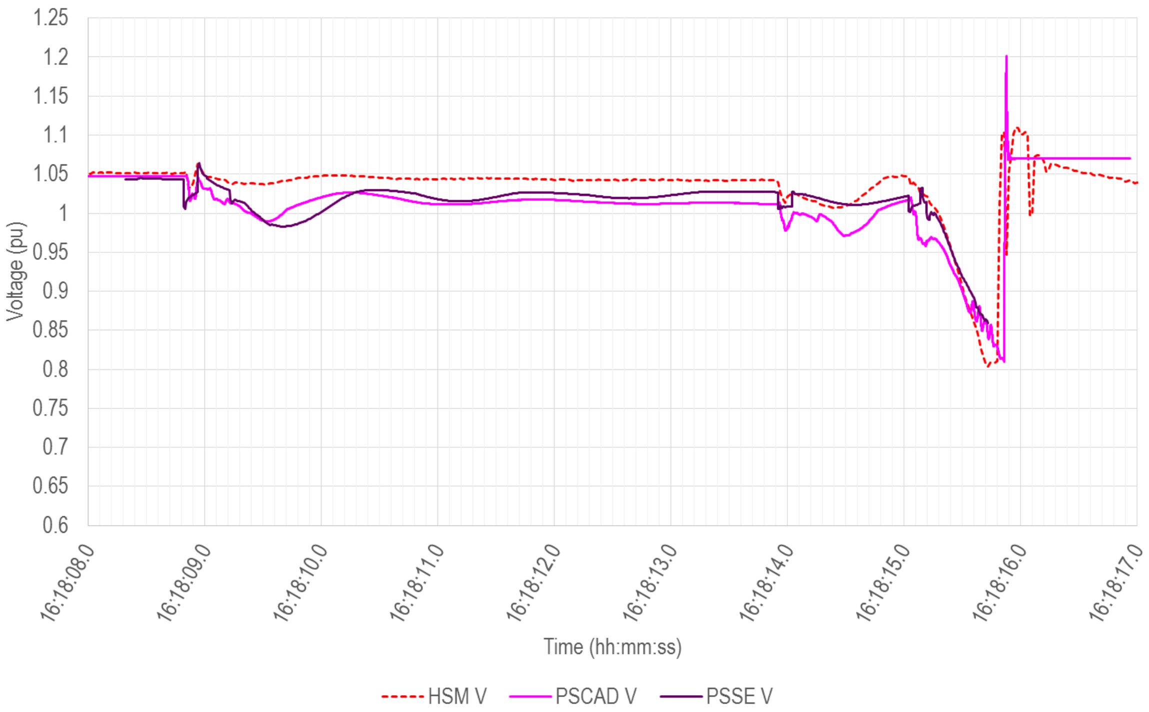


Figure 146 shows a good match between modelling and measured (HSM) values, except for the PSS/E result for peak power flow. This difference has no material impact on predicting whether loss of synchronism and islanding conditions will occur, as this is determined by the impedance trajectory.

In Figure 135 and Figure 140, close alignment between the measured and simulated impedance trajectories can be observed.

Figure 146 Active power transfer at Heywood Interconnector

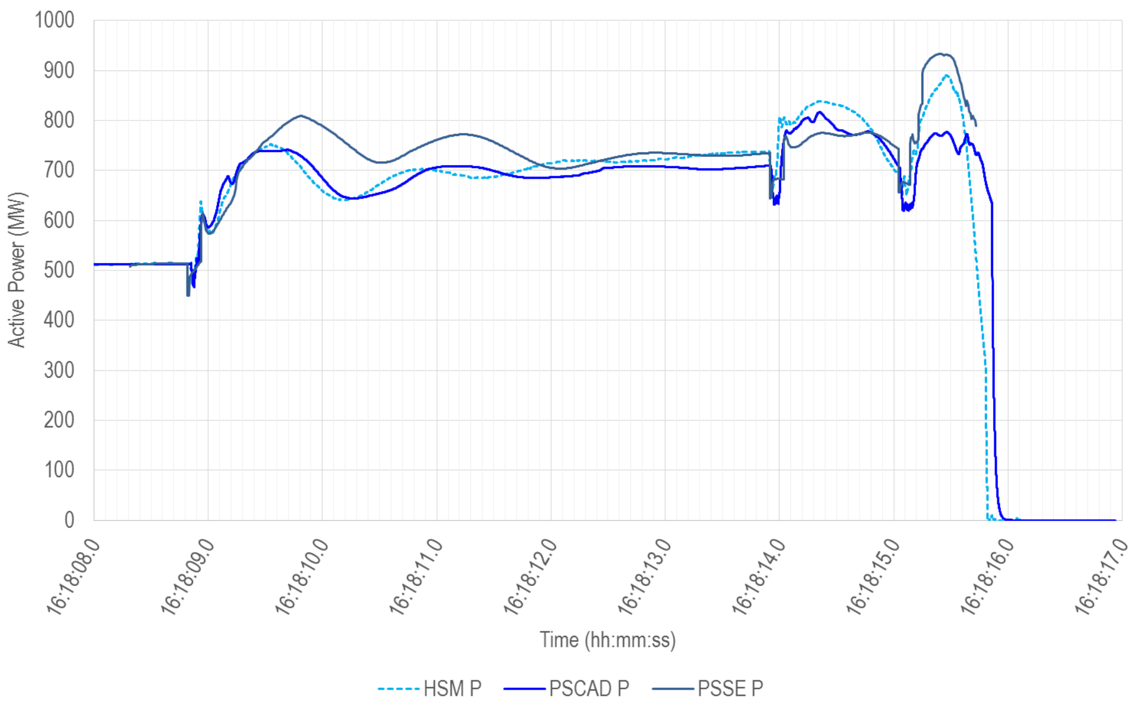
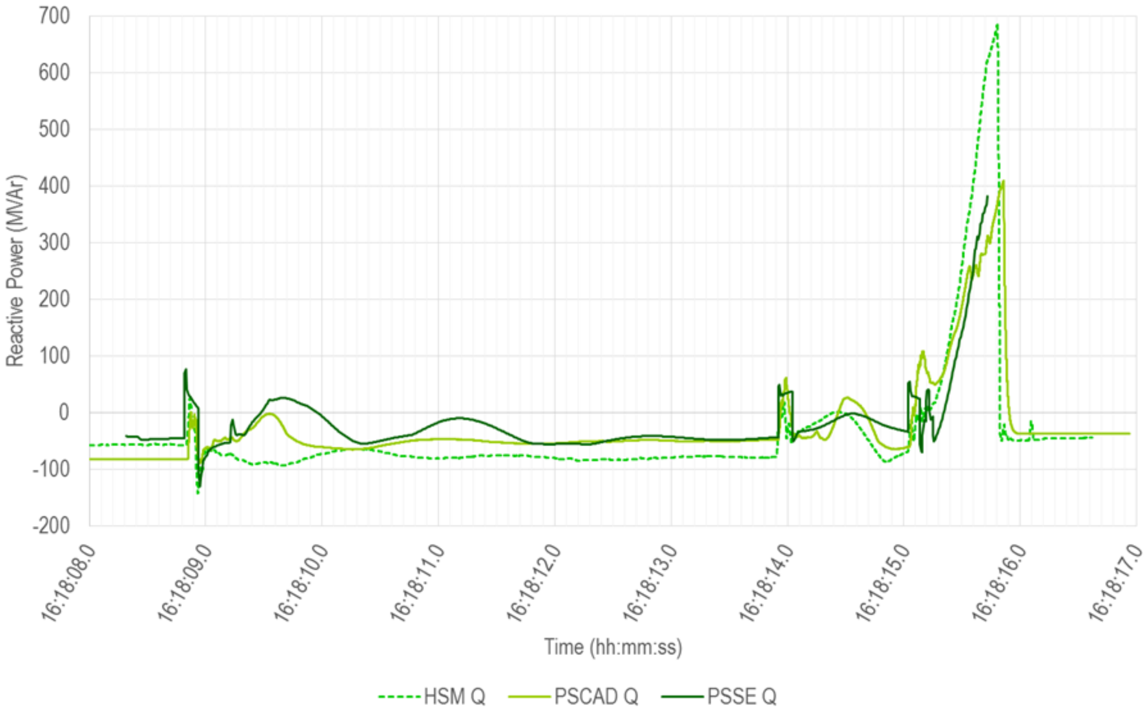


Figure 147 shows that modelling values for peak reactive power flow at 16:18:15.8 is less than the measured (HSM) value. Good correlation can be observed for remainder of the response. One contributor to this difference is load shake off and disconnection during the actual incident which could not be accounted for in the simulation models, even with detailed load models. This difference has no material impact on predicting whether loss of synchronism and islanding conditions will occur, as this is determined by the impedance trajectory (shown in Figure 135 and Figure 140).

Figure 147 Reactive power transfer at Heywood Interconnector



APPENDIX X. ASSESSMENT OF ADDITIONAL RISKS FOR SYSTEM SECURITY IN SOUTH AUSTRALIA

This Appendix has been added to this final report.

X.1 Risk of transient wind farm reduction due to a single credible fault

This sub-section investigates the impact of a single credible contingency fault in the SA transmission network on the Heywood Interconnector transfer capability, and hence the risk of loss of synchronism and islanding conditions.

X.1.1 Summary

Operating conditions

PSS/E and PSCAD simulation studies were conducted considering the following key operating conditions:

- A two-phase-to-ground fault was applied for all scenarios studies.
- Fault clearance times of 100 ms and 120 ms were assumed for the close and remote ends of the lines, in accordance with the fault clearance times specified in the System Standards under NER schedule S5.1a, and consistent with ElectraNet's practices.
- A fault at Snowtown 2 Wind Farm's connection point, resulting in loss of 270 MW of wind generation, was determined to have the highest impact on Heywood Interconnector stability.[136] Studies reported in this section therefore focus on a two-phase-to-ground fault at Snowtown 2 Wind Farm only.

  Such a fault would also result in the voltage at the LV terminals of wind turbines at Mt Millar Wind Farm dropping below their LVRT activation threshold of 0.8 pu, instigating zero power mode of operation.
- All scenarios were conducted with five high-inertia synchronous generating units being on-line, to meet the 3 Hz/s RoCoF for which the UFLS scheme is demonstrated to succeed with a high confidence. This includes three TIPS B units, and two Pelican Point CCGT generating units. Table 26 shows the active power output of all wind farms and synchronous generators for all scenarios discussed in Appendix X, and compares them against the pre-event generation dispatch.
- Hornsdale 2 Wind Farm was assumed to be operational and generating at its full capacity. No other new wind or solar farms were included in the integrated models.
- The revised LOS relay settings implemented in October 2016 have been used in the scenario analysis.
- Minor differences exist between the dispatch levels of the five on-line synchronous machines for the three import levels studied.

Table 26 Comparison of on-line generators for the event and scenario analysis

Generator	Output during the event (MW)	Output for scenario analysis (MW)
The Bluff Wind Farm	43	52.5
Clements Gap WF	14	57
Canunda WF	43	39
Cathedral Rocks	0	50
Hallett WF	38	94.5

[136] Note that a fault resulting in disconnection of Lake Bonney 1, 2, and 3 wind farms would not activate zero power mode at Mt Millar wind farm, leading to a smaller sustained power reduction across the SA wind farms.

Generator	Output during the event (MW)	Output for scenario analysis (MW)
Hallett Hill WF	42	71
Hornsdale 1 WF	86	102
Hornsdale 2 WF	N/A	102
Lake Bonney 1 WF	77	45
Lake Bonney 2 WF	149	125
Lake Bonney 3 WF	35	20
Mt Millar WF	67	62
North Brown Hill WF	85	110
Snowtown WF	0	98
Snowtown North WF	44	144
Snowtown South WF	65	126
Starfish Hill WF	0	0
Waterloo I WF	95	111
Waterloo II WF	N/A	20
Wattle Point WF	0	0
Total Wind Generation (MW)	**883**	**1437**
Ladbroke Grove Unit 1	42	0
Ladbroke Grove Unit 2	40	0
Pelican Point GT	0	87
Pelican Point ST	0	56
Torrens Island B PS Unit 1	82	54
Torrens Island B PS Unit 3	84	50
Torrens Island B PS Unit 4	82	50
Total synchronous generation (MW)	**330**	**297**

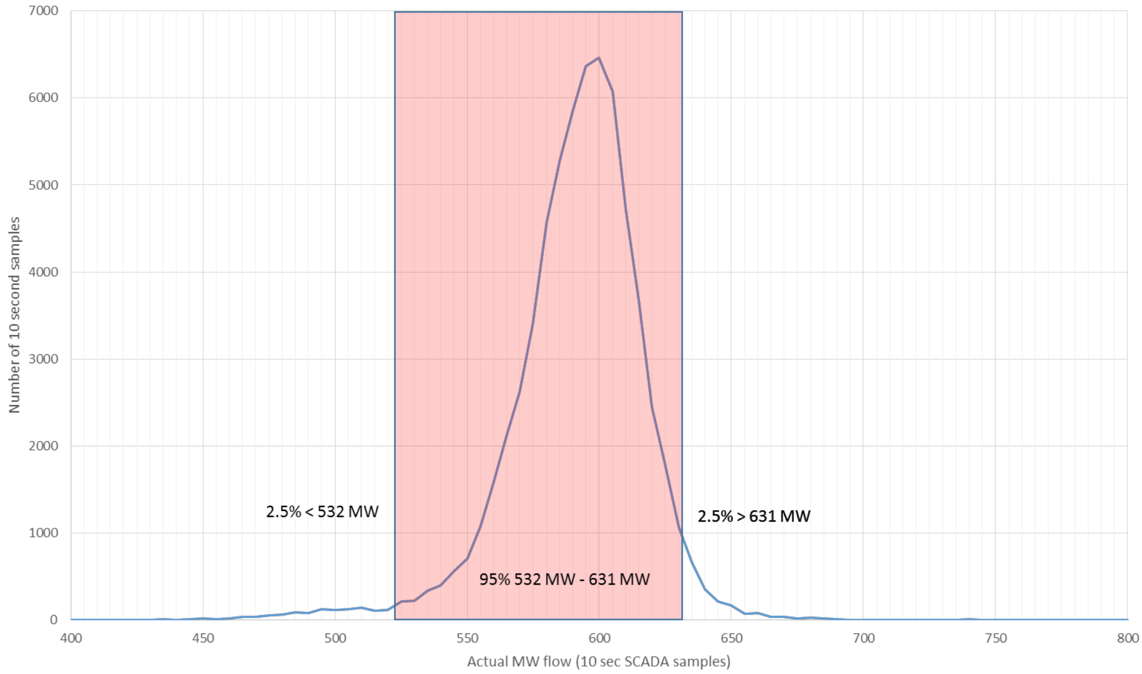
Studies documented in Appendix X considered three import dispatch levels for the Heywood Interconnector, of 650 MW (planned import limit), 600 MW (current import limit), and 550 MW.

However, historical analysis of import variations at the Heywood Interconnector for a dispatch target of 600 MW indicates that a 95% confidence level within a 5-minute dispatch interval could result in the actual flows reaching 630 MW for the same dispatch period, as clearly highlighted in Figure 148.

Data was collected for this analysis when the actual target for Heywood Interconnector was between 595 MW and 600 MW relative to the current maximum target of 600 MW. Figure 148 is based on the actual 10-second SCADA MW, and distribution of these actual SCADA flows.

Note that the distribution is skewed to flow below 600 MW, due to the use of a dynamic operating margin to manage the 600 MW limit. When actual flow exceeds 600 MW, the operating margin is increased for the next 5-minute period.

Figure 148 Actual Heywood Interconnector flows with a dispatch target of 600 MW



This analysis confirmed a drift of up to 30 MW in the actual flows, compared to the target flows.

To account for this natural drift, the three import levels stated above were each increased by 30 MW. The three import levels analysed by the PSS/E and PSCAD simulation were, therefore, 680 MW, 630 MW, and 580 MW.

Results

PSS/E studies were carried out for all three import levels of 680 MW, 630 MW, and 580 MW. These studies indicate that loss of synchronism and system separation can occur for a single credible fault in the SA transmission system for the 680 MW and 630 MW import levels, but not for the 580 MW level, even when the 3 Hz/s RoCoF constraint is binding.

These conclusions were corroborated by PSCAD simulation studies for the 680 MW and 630 MW import levels. Consistent results from two independent simulation platforms provide high confidence in the veracity of these conclusions.

Note that PSCAD results are presented with the Interconnector opening 50 ms after the impedance trajectory crosses the inner blinder of the loss of synchronism relay. However, PSS/E simulation would have stopped immediately after islanding. For this reason PSS/E simulation results are presented with the Interconnector closed, however, system instability is still observable.

The following key traits can be consistently seen in both the PSS/E and PSCAD studies[137]:

- Loss of synchronism events due to sustained reduction of several hundred MW of generation manifest themselves with declining voltage magnitudes and increasing voltage phase angles beyond 90 degrees across the SA power system.

  This can be seen from Figure 151, Figure 156, Figure 161, and Figure 166 (which show PSS/E and PSCAD simulations of system voltage magnitudes for the 680 MW and 630 MW import levels), as well as Figure 152, Figure 157, Figure 162, and Figure 167 (which highlight system voltage phase angles).
- The loss of synchronism events when operating at 680 MW and 630 MW import levels evolve approximately three times slower than those which occurred in the time between the fault

[137] PSS/E simulation studies are conducted for the 680, 630, and 580 MW import levels. PSCAD studies are used to verify the PSS/E results for the two unstable import levels of 680 MW and 630 MW.

clearance and the Heywood Interconnector opening. This is evident from Figure 149, Figure 154, Figure 159, and Figure 164, which show active and reactive power transfer across the Heywood Interconnector.

- Figure 150, Figure 155, Figure 160, and Figure 165 indicate that the loss of synchronism relay correctly operates for unstable power swings for the 680 MW and 630 MW import levels, and blocks operation for stable power swings at 580 MW import level. The relay, therefore, operates where it should and does not operate where it should not.
- The frequency variations prior to the system separation are not sufficient to activate the UFLS scheme (see Figure 153, Figure 158, Figure 163, and Figure 168).

The study results and conclusions presented in this report are based on five high-inertia synchronous generators being on-line in SA. AEMO has not carried out any studies to determine the extent to which operating with a larger number of on-line synchronous generators would assist in the stable and secure operation of the Heywood Interconnector, above the 550 MW dispatch level demonstrated to be a stable operating point.

X.1.2 Simulation results

Appendix X.1.2 presents the following simulation case studies:

- PSS/E simulation for the 680 MW, 630 MW, and 580 MW Heywood Interconnector import levels.
- PSCAD simulation for the 680 MW and 630 MW import levels.

For each of the five simulation studies, the following quantities were used to determine system stability or otherwise for a single credible fault:

- Heywood active and reactive power flow.
- Heywood impedance trajectory.
- System voltage magnitudes.
- System voltage phase angles.
- System frequencies.

680 MW import level

PSS/E simulation studies

Figure 149 Active and reactive power transfer at Heywood Interconnector

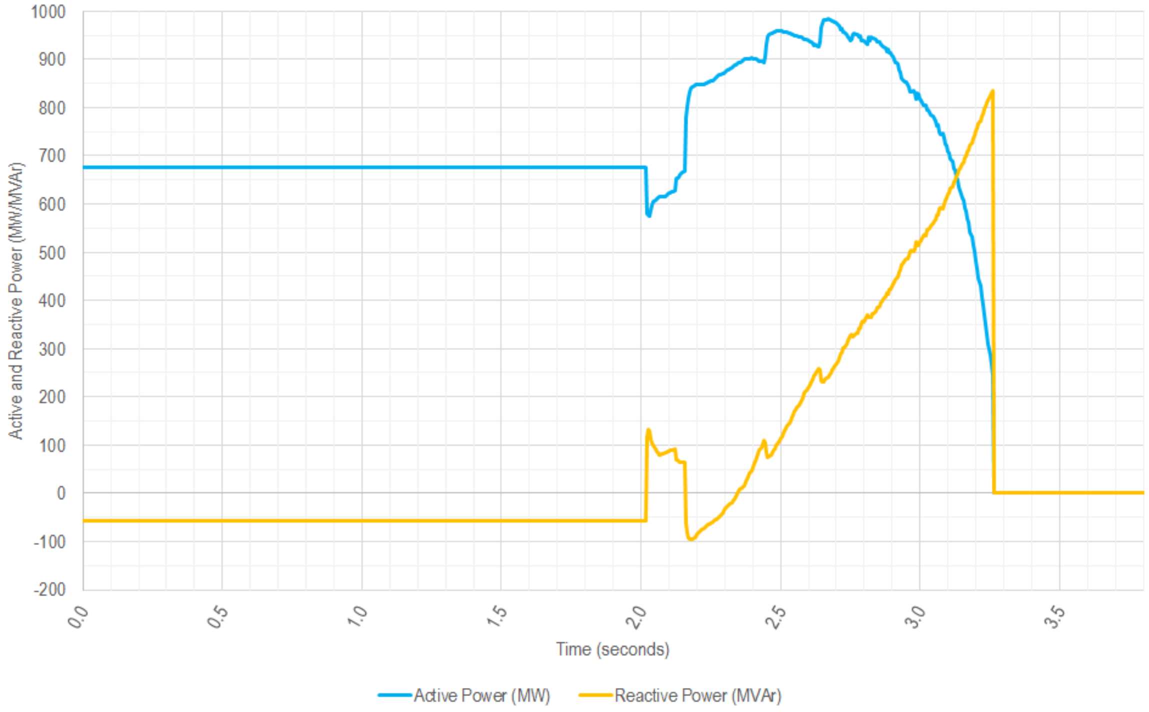


Figure 150 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

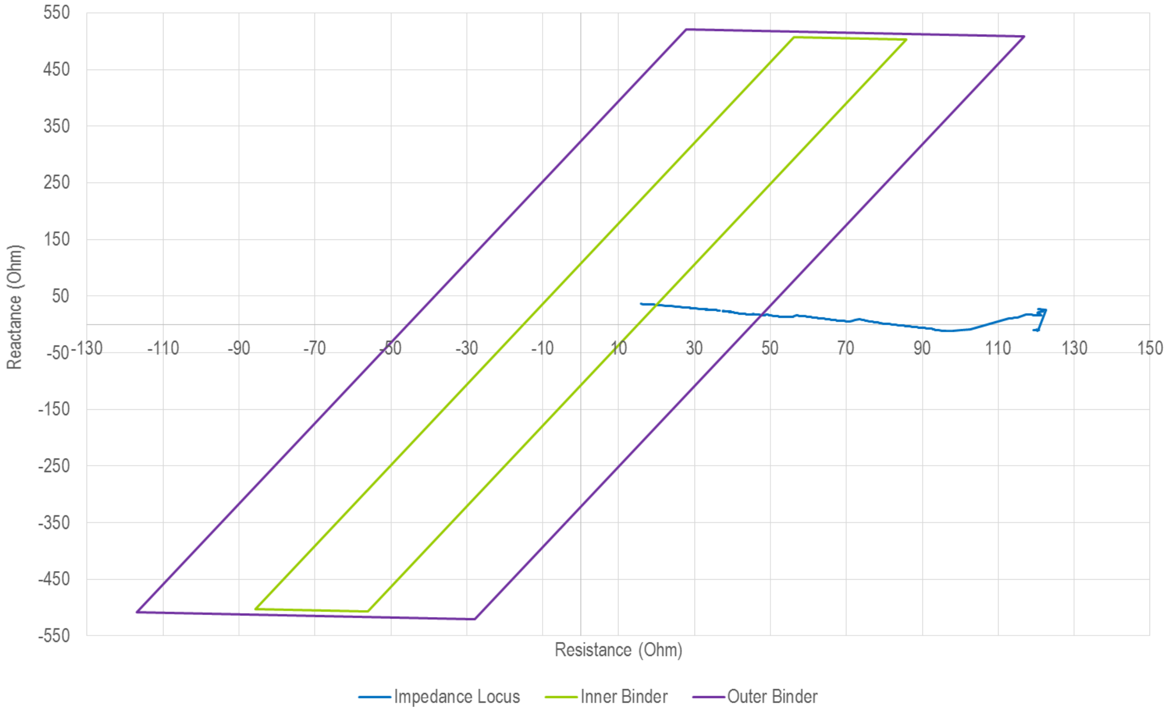


Figure 151 Voltage magnitudes at key SA 275 kV substations

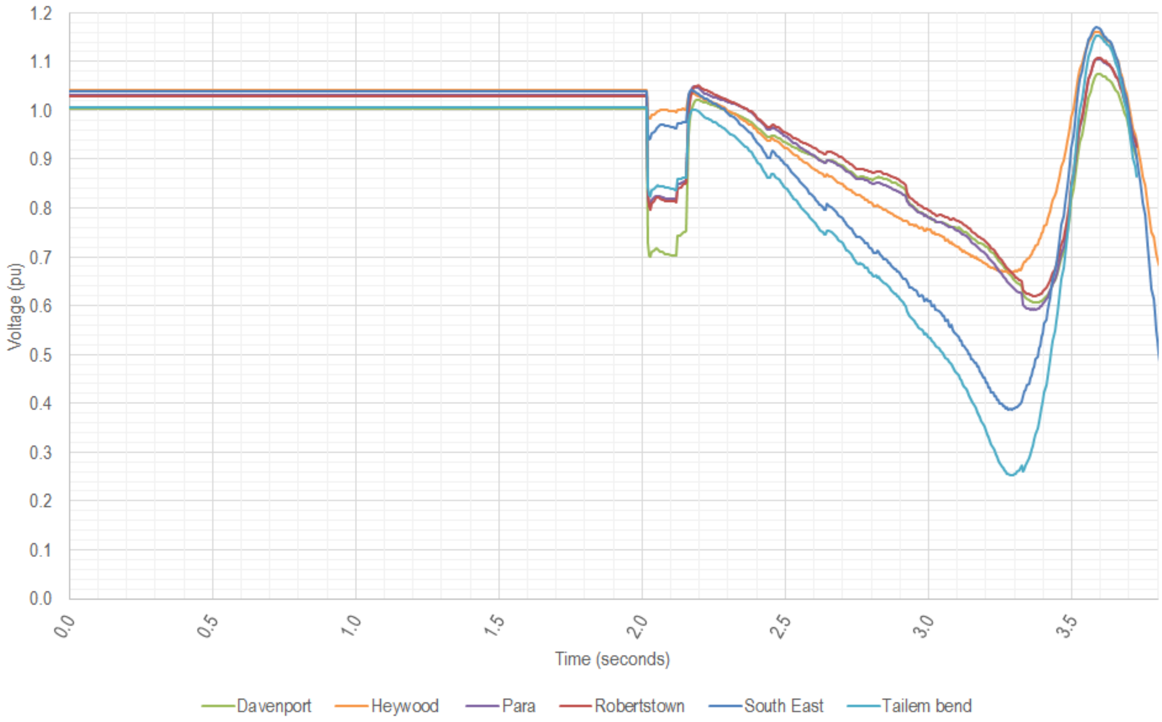


Figure 152 Voltage phase angles relative to HYTS at key SA 275 kV substations

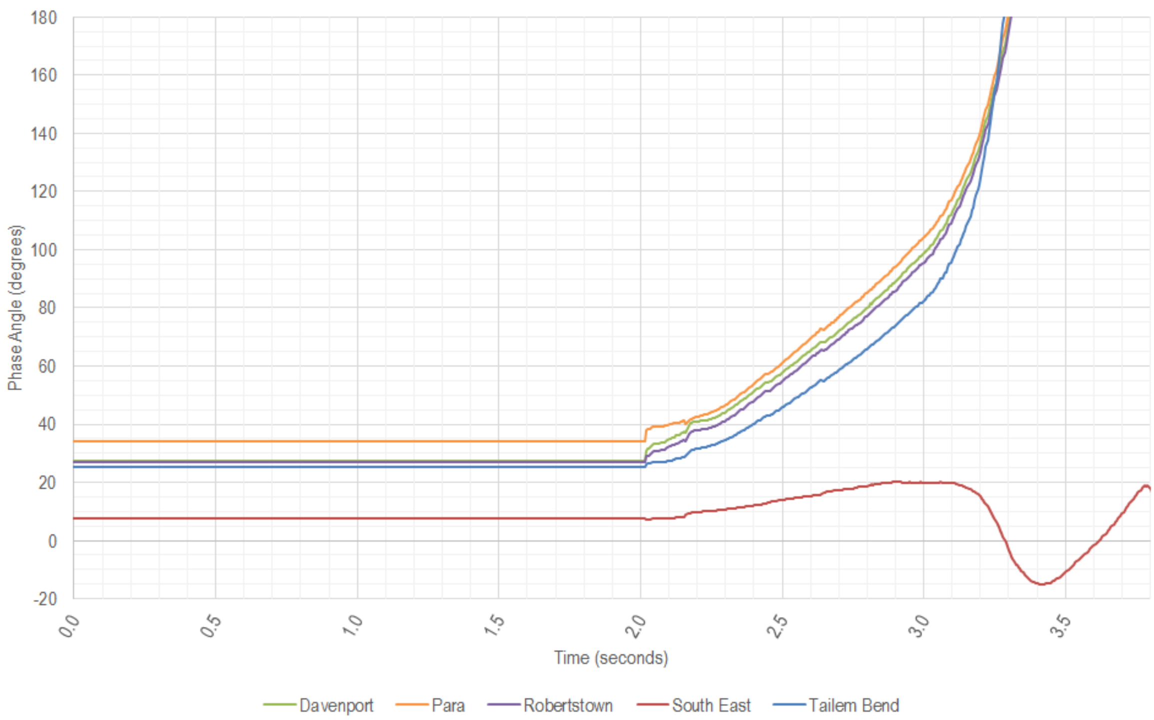
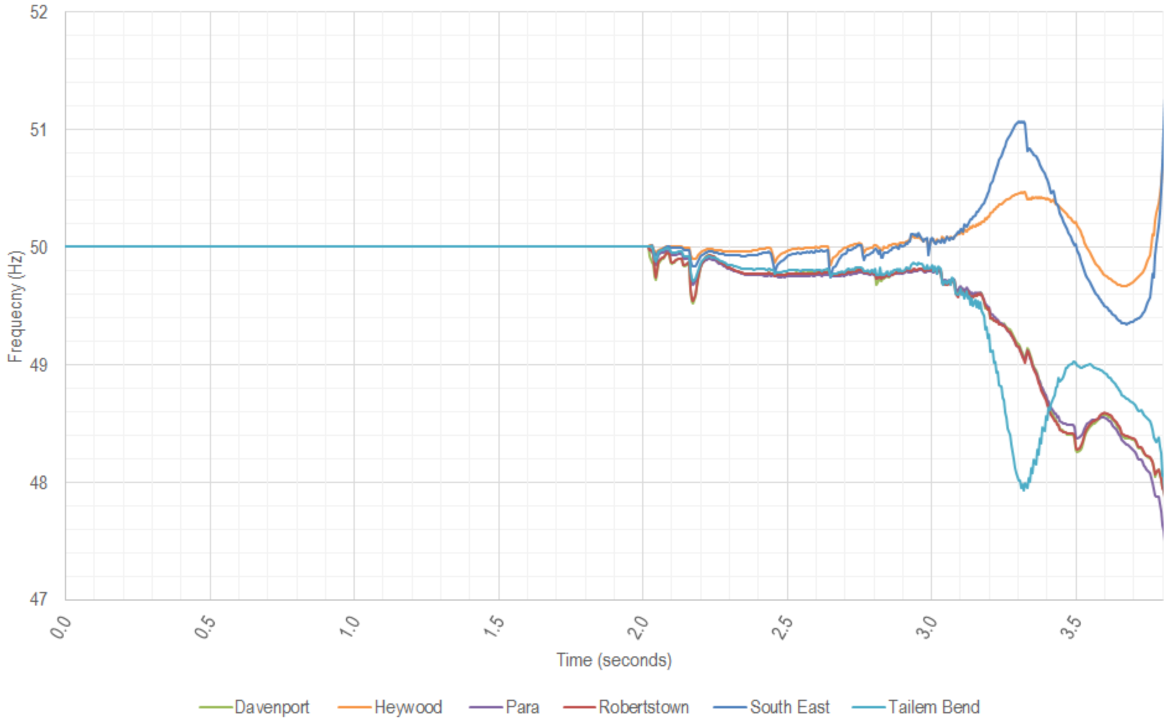


Figure 153 Frequencies at key SA 275 kV substations



PSCAD simulation studies

Figure 154 Active and reactive power transfer at Heywood Interconnector

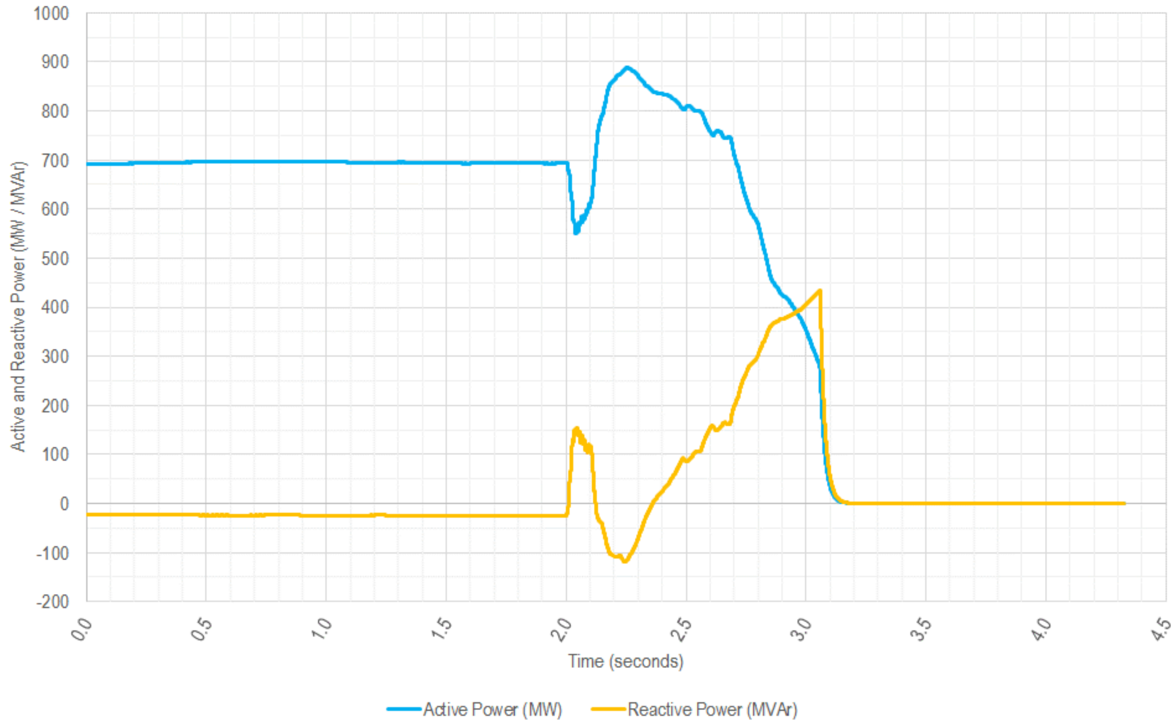


Figure 155 PSCAD Impedance trajectory at Heywood Interconnector against relay characteristic area

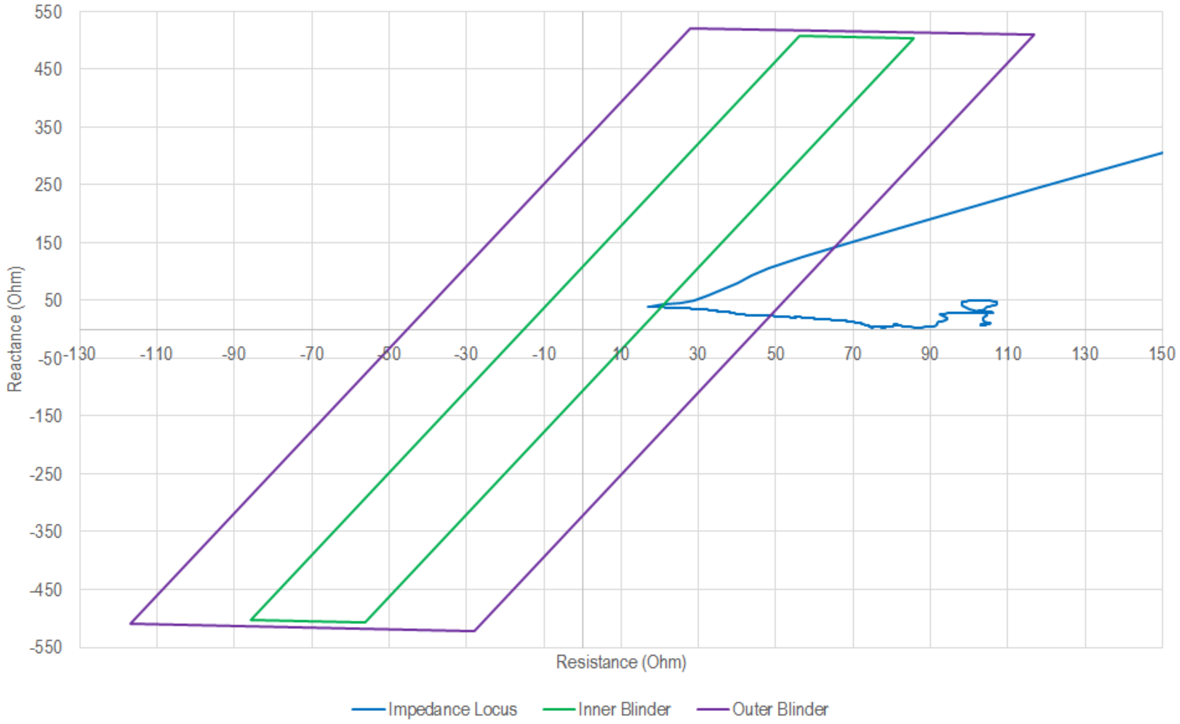


Figure 156 Voltage magnitudes at key SA 275 kV substations

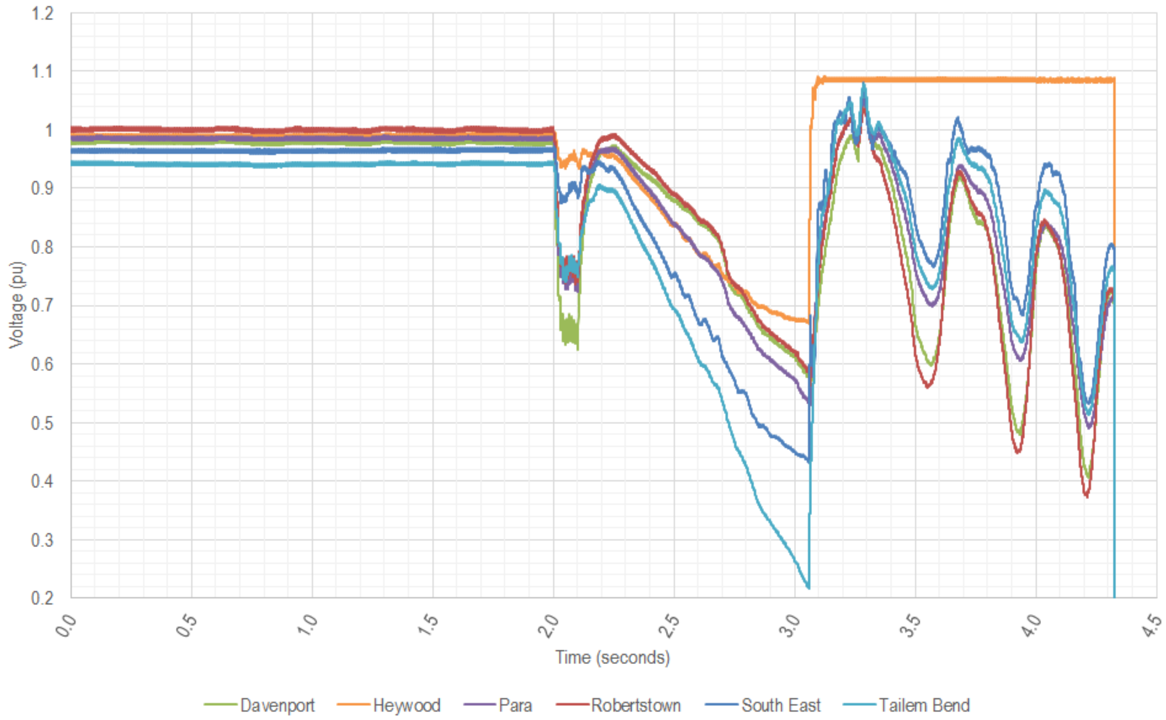
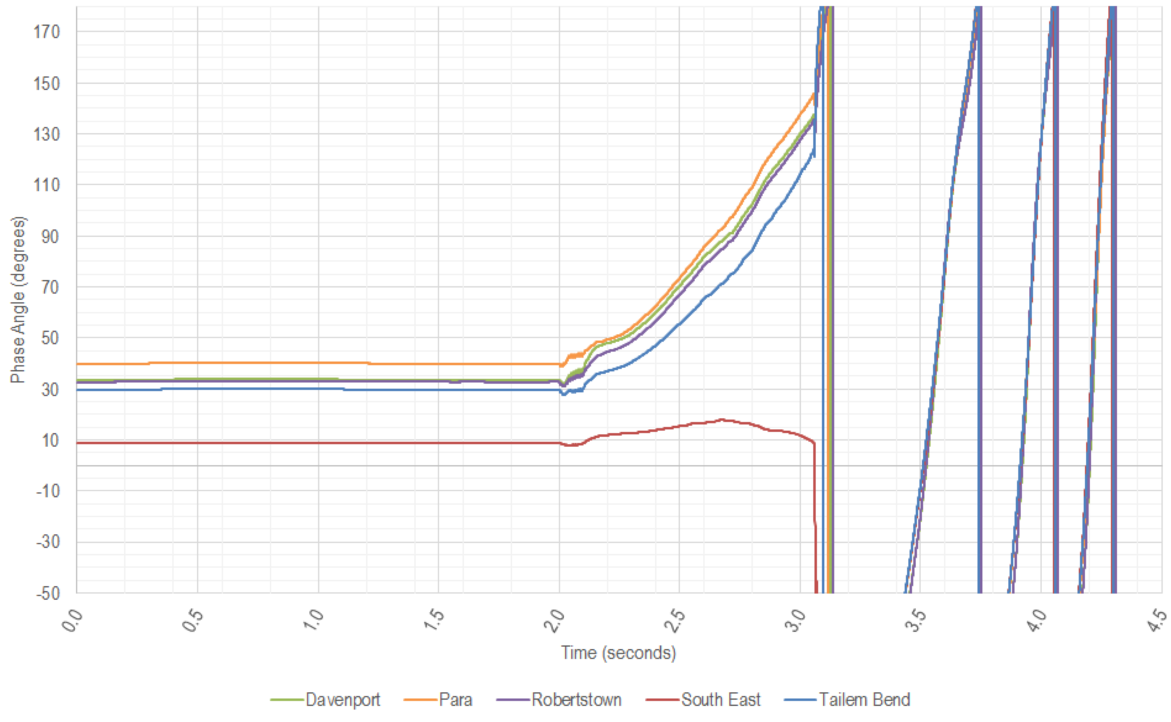
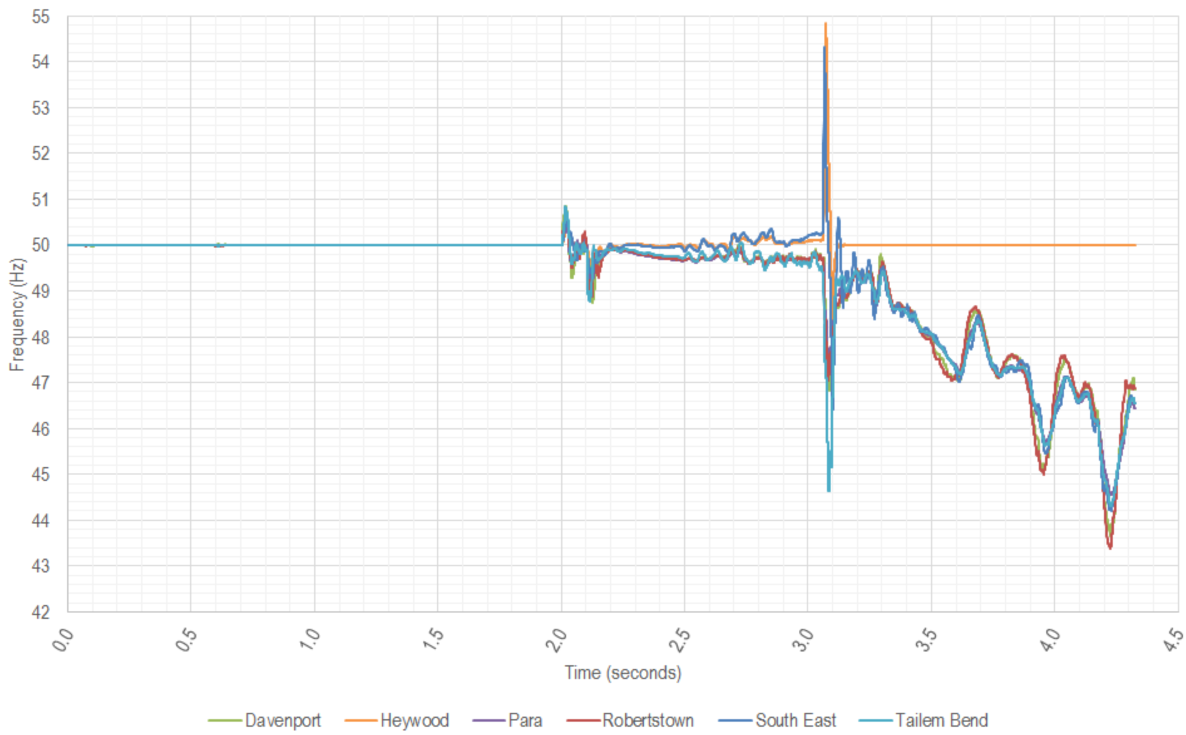


Figure 157 Voltage phase angles relative to HYTS at key SA 275 kV substations



Note that large spikes seen at 3.1 seconds in Figure 158 stem from the inherent inability of simulation tools to track the abrupt changes in voltage phase angles and RoCoF.

Figure 158 Frequencies at key SA 275 kV substations



630 MW import level

PSS/E simulation studies

Figure 159 Active and reactive power transfer at Heywood Interconnector

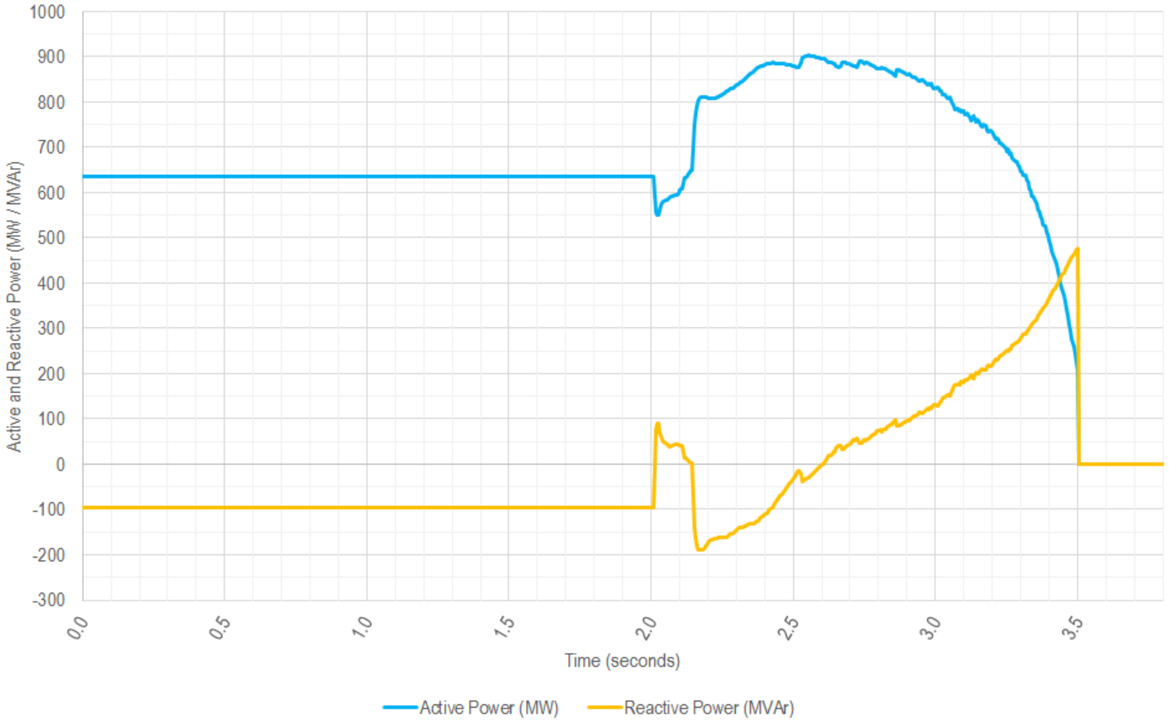


Figure 160 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

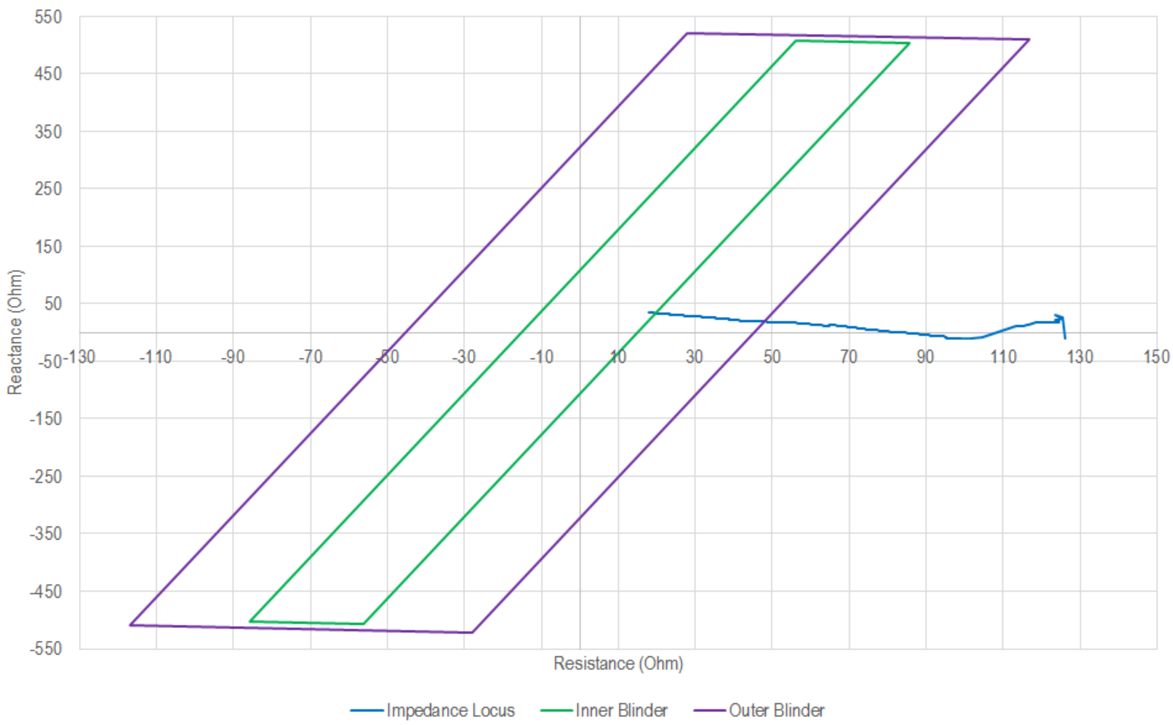


Figure 161 Voltage magnitudes at key SA 275 kV substations

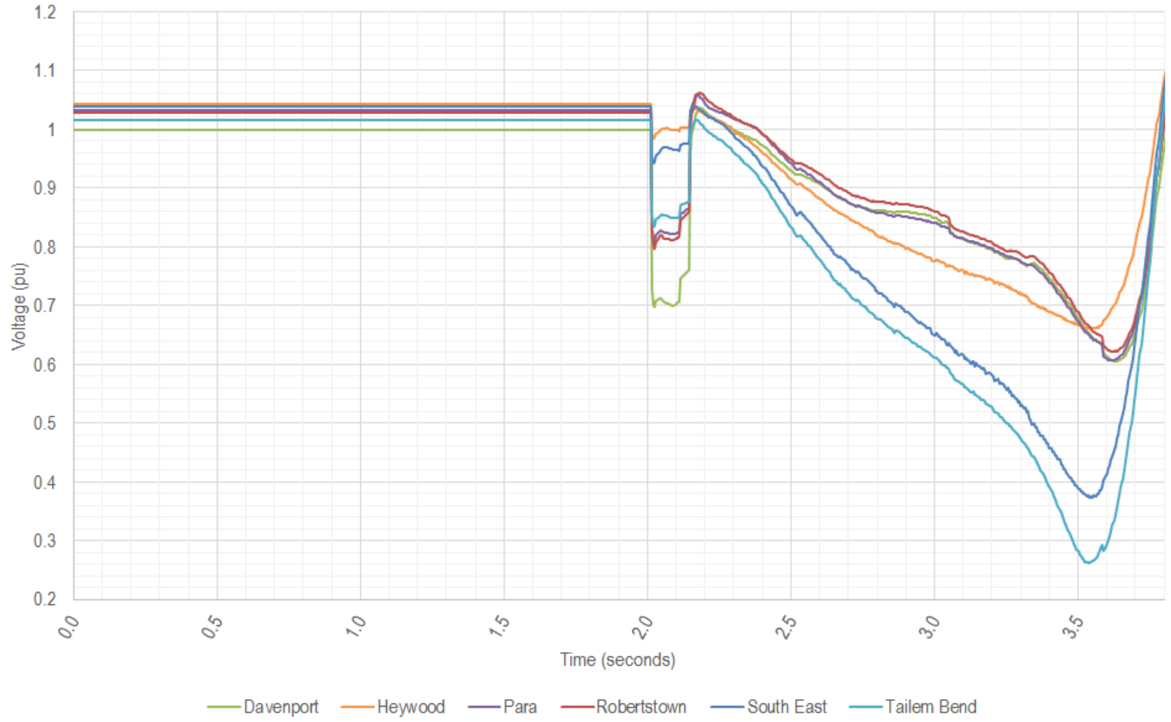


Figure 162 Voltage phase angles relative to HYTS at key SA 275 kV substations

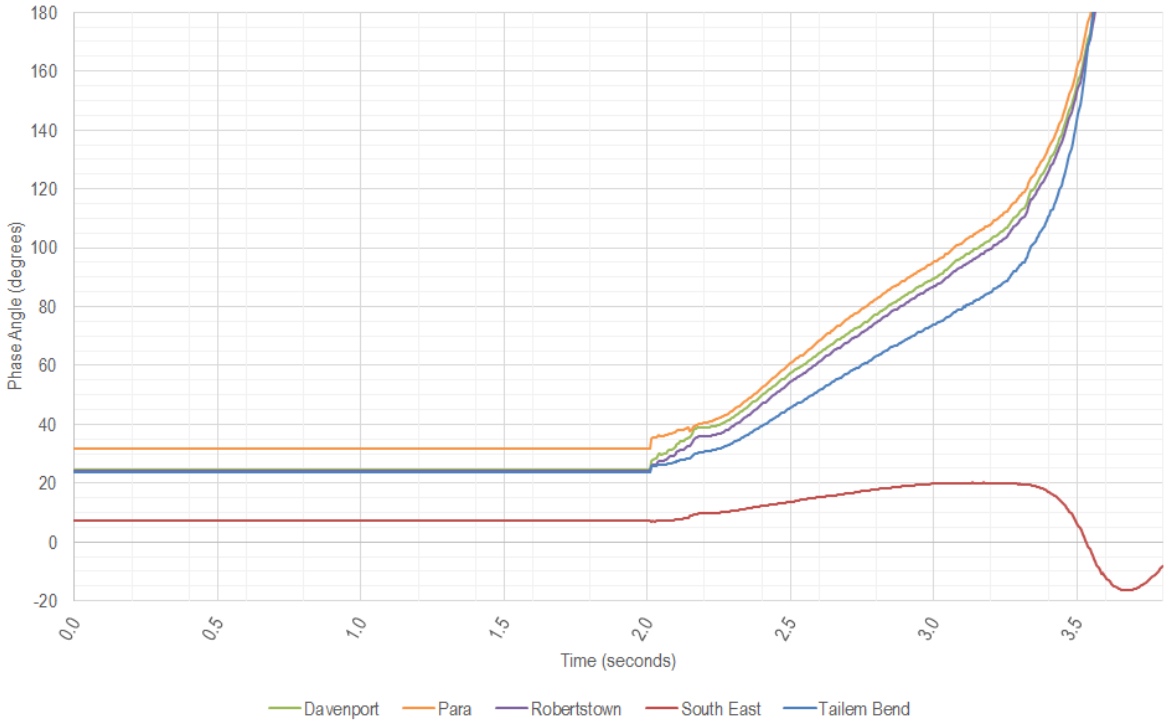
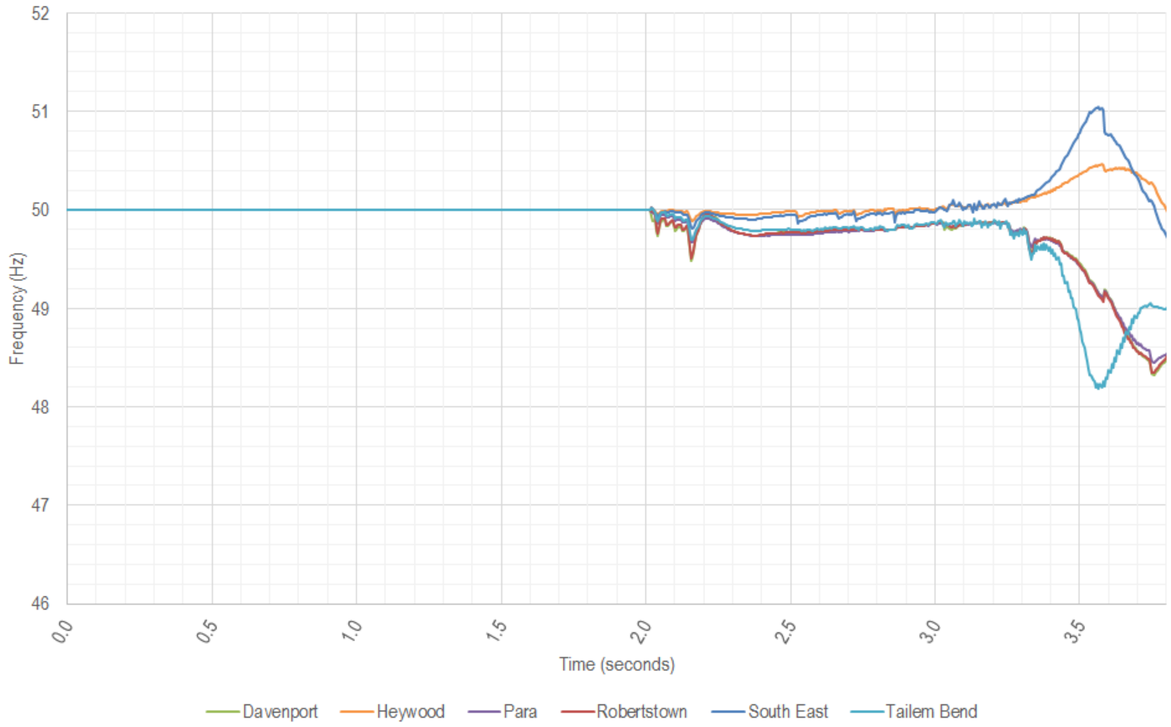


Figure 163 Frequencies at key SA 275 kV substations



PSCAD simulation studies

Figure 164 Active and reactive power transfer at Heywood Interconnector

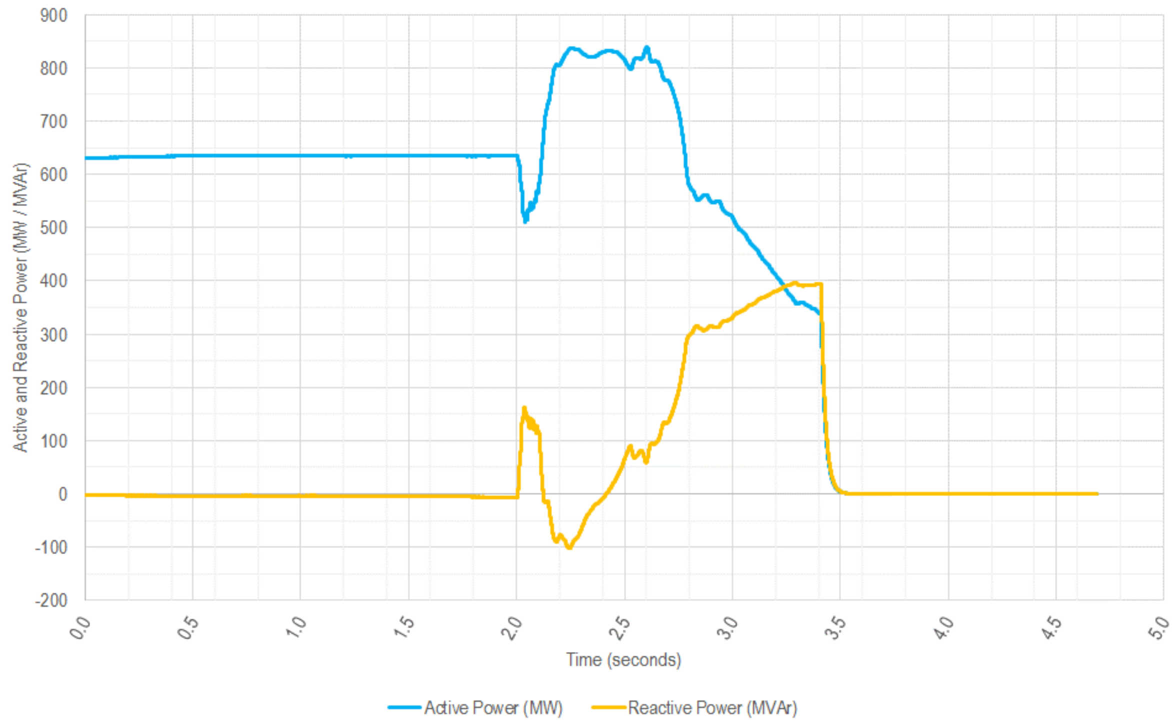


Figure 165 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

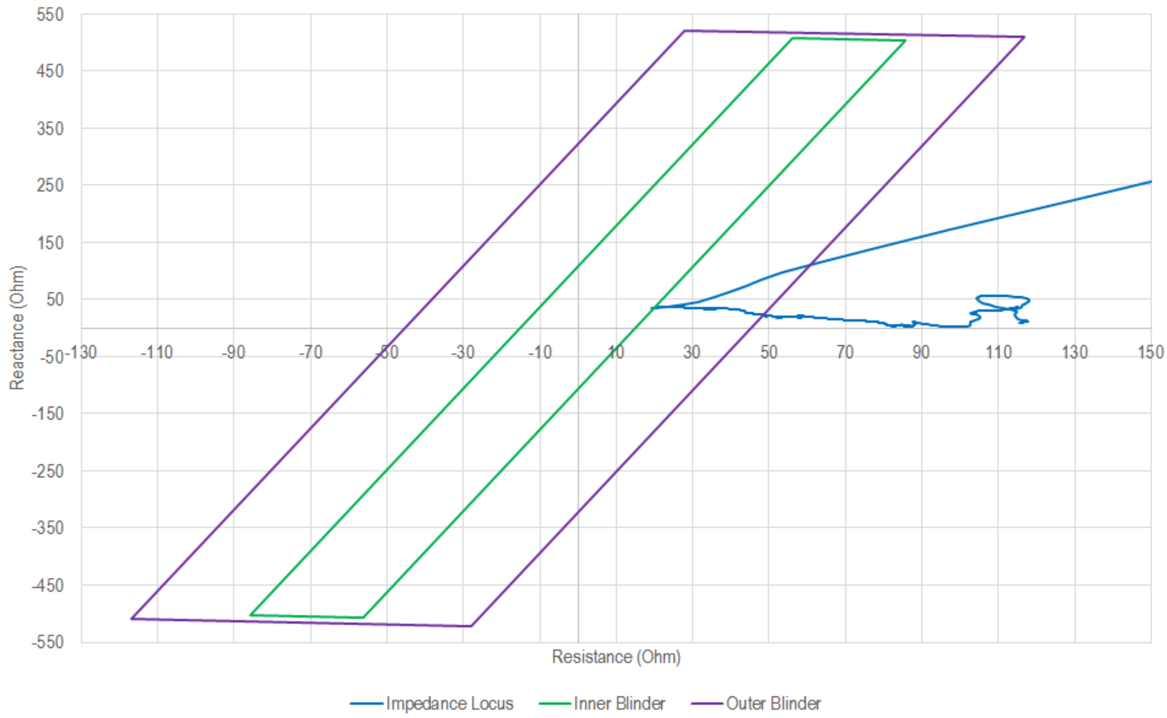


Figure 166 Voltage magnitudes at key SA 275 kV substations

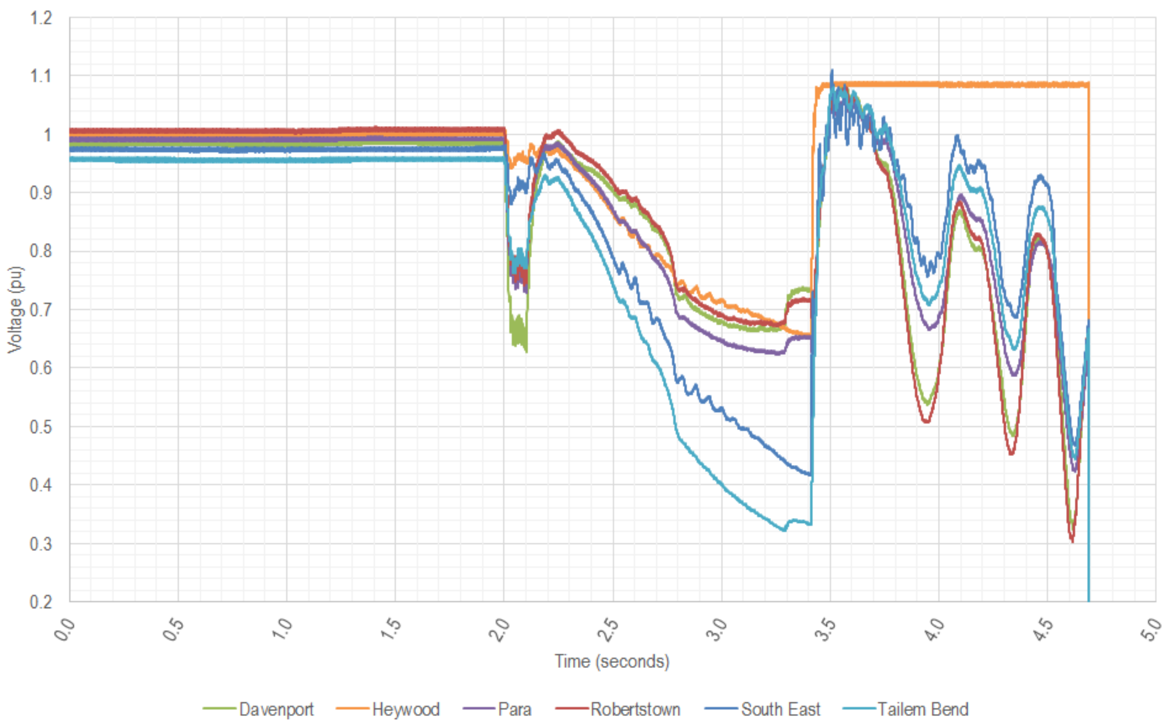


Figure 167 Voltage phase angles relative to HYTS at key SA 275 kV substations

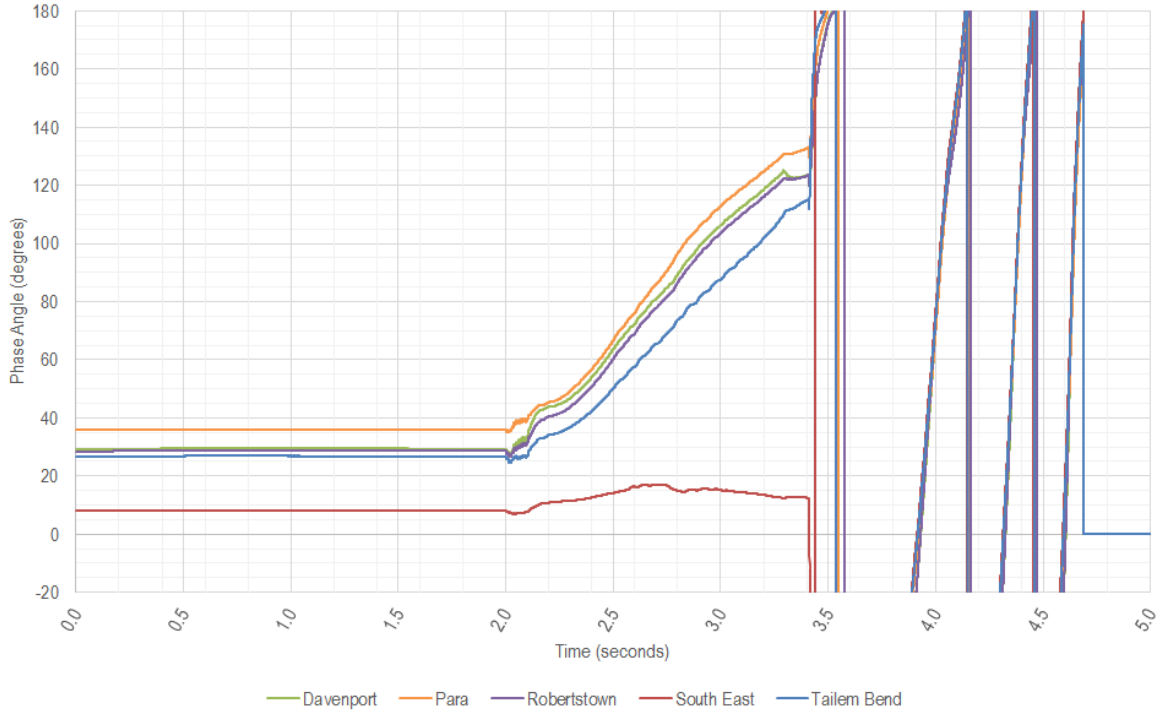
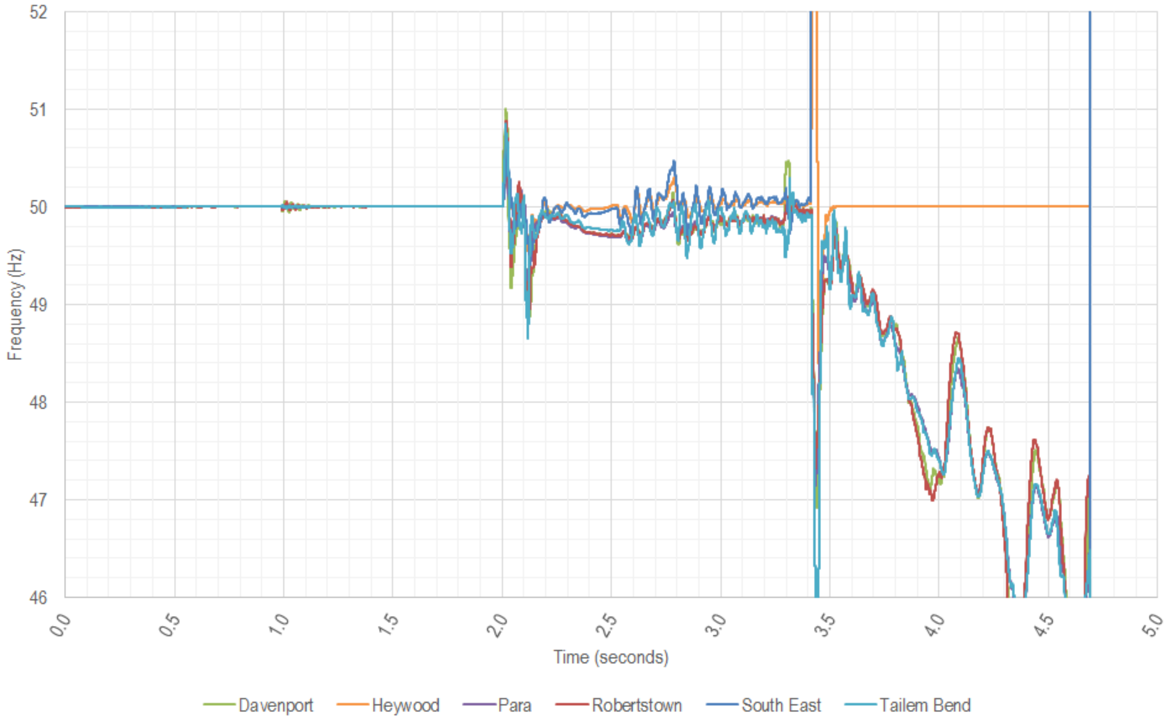


Figure 168 Frequencies at key SA 275 kV substations



580 MW import level

PSS/E simulation studies

Figure 169 Active and reactive power transfer at Heywood Interconnector

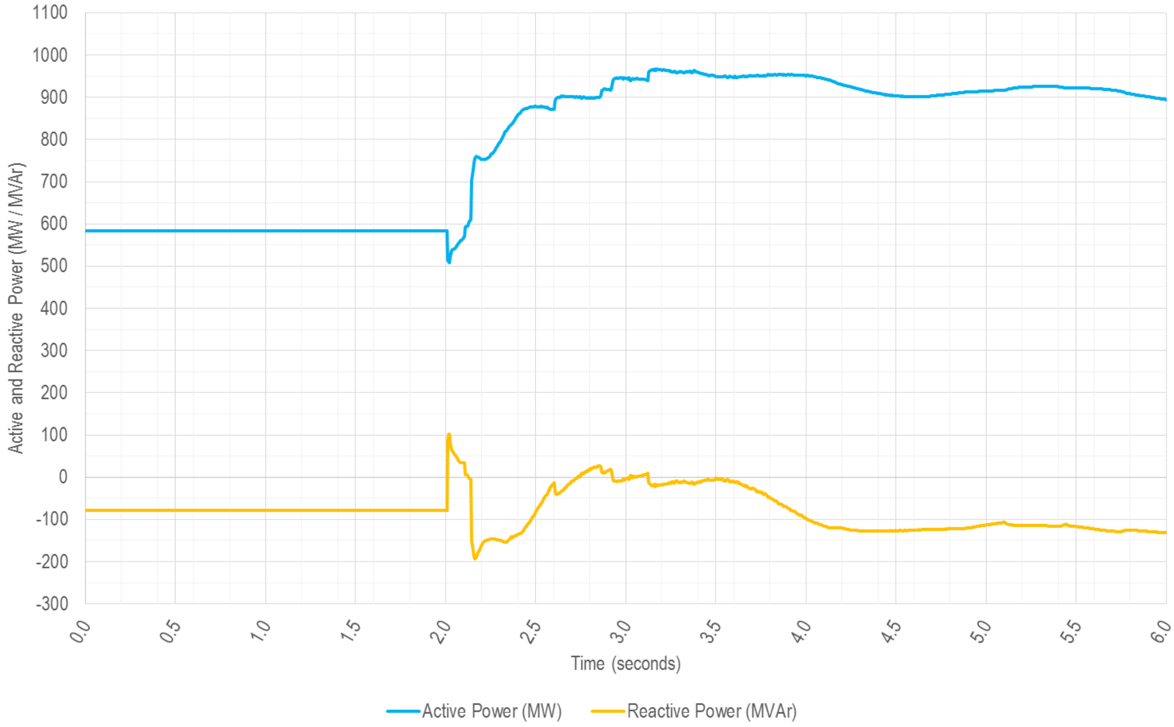


Figure 170 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

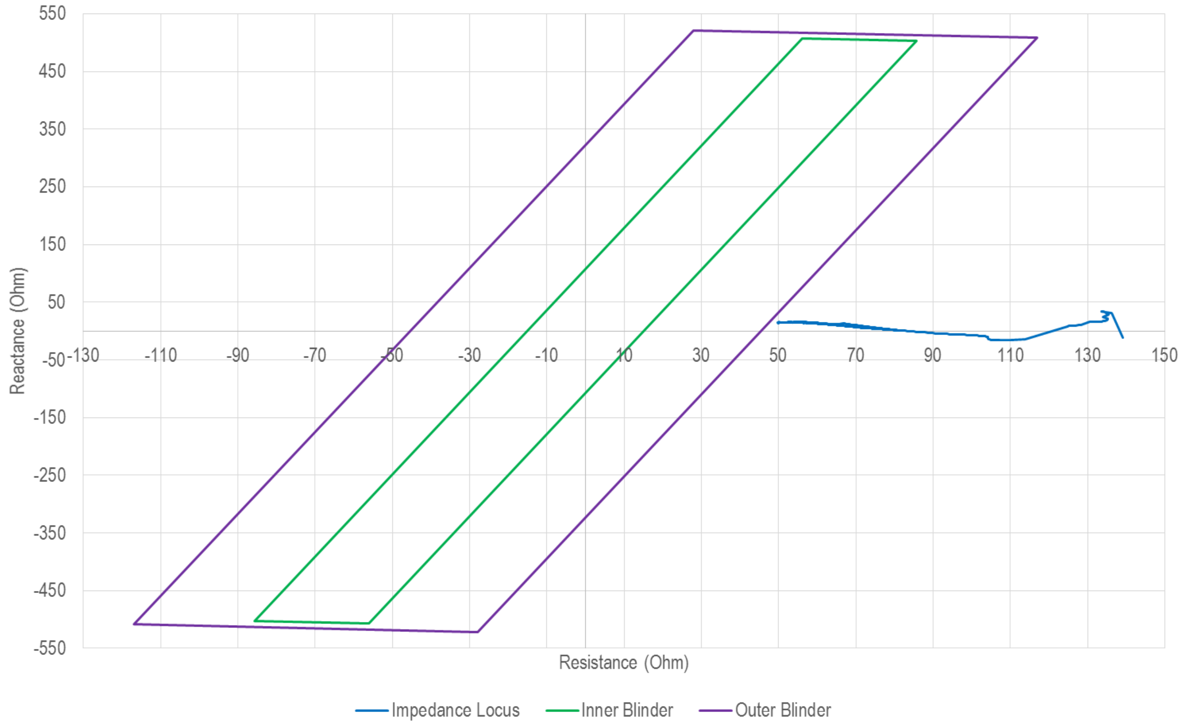


Figure 171 Voltage magnitudes at key SA 275 kV substations

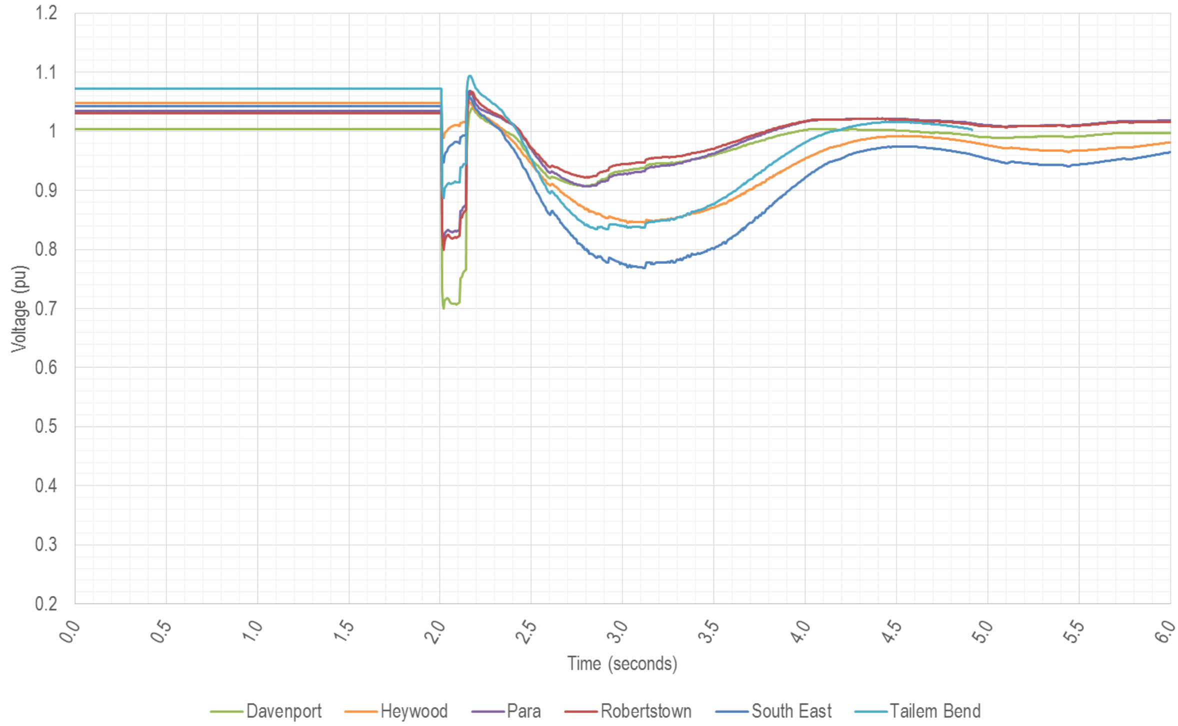


Figure 172 Voltage phase angles relative to HYTS at key SA 275 kV substations

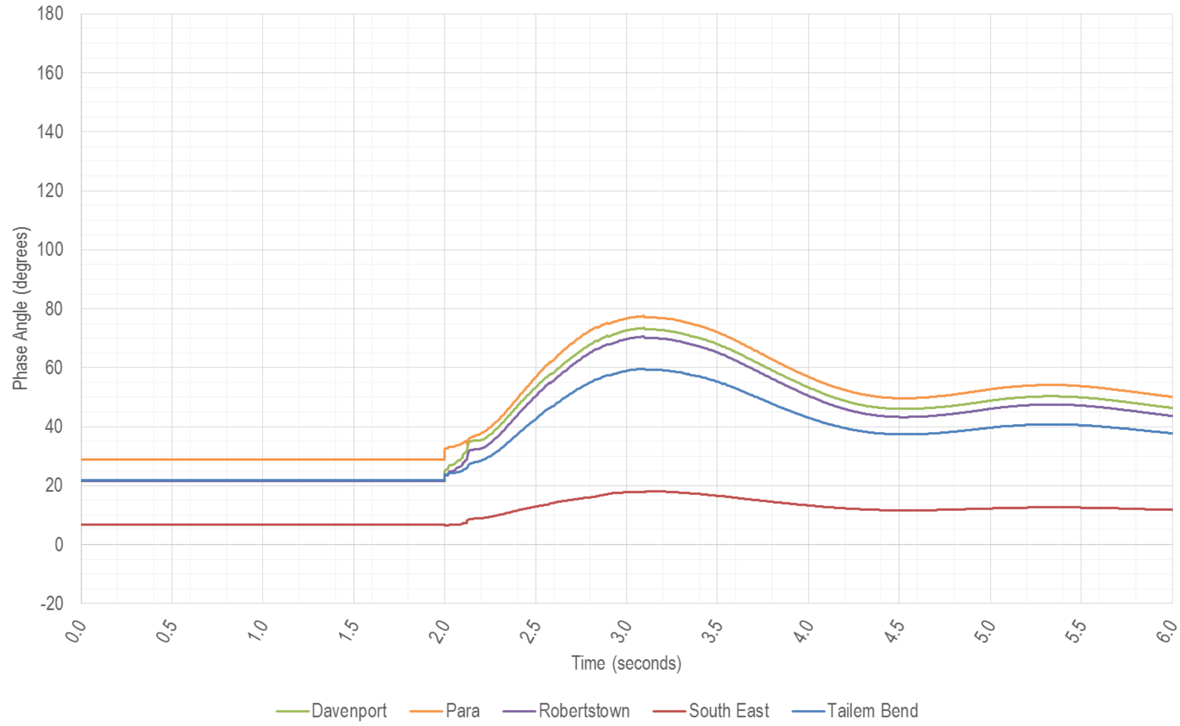
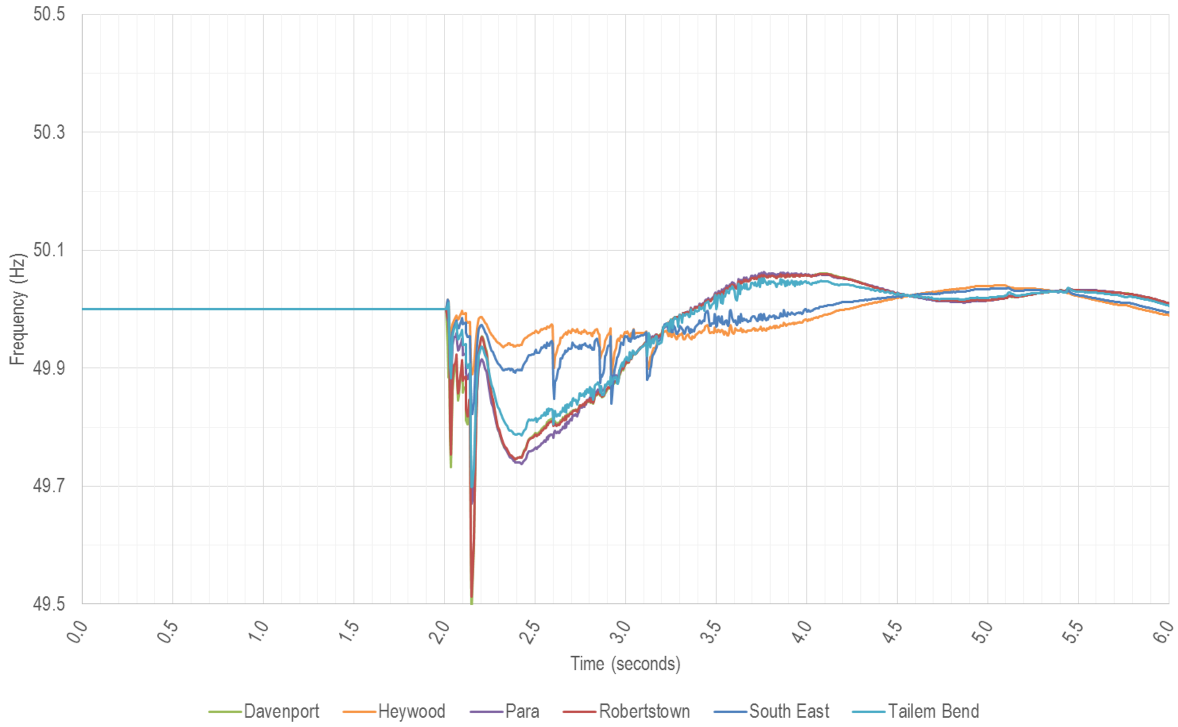


Figure 173 Frequencies at key SA 275 kV substations



X.2 Remaining level of risk of wind farm output reduction due to multiple voltage disturbances

X.2.1 Historical faults in South Australian power system

ElectraNet has analysed power system faults that have occurred over the years 2007 to 2016. The data is based on tripping of ElectraNet transmission assets for events that have been determined to be primary faults. It includes auto-reclosing events, so a trip followed by an unsuccessful reclose is considered as two faults.

Over this period, the maximum number of faults that have occurred within 2, 30, or 120 minutes, consistent with the known capability of various wind turbine types indicated in Table 10, are:

- Within 2 minutes – 5 faults.
- Within 30 minutes – 11 faults.
- Within 120 minutes – 16 faults.

This data considers faults that resulted in ElectraNet assets operating, and excludes faults originated from the SA distribution network, or Victorian transmission network. For example, fault number 1 in Table 7 occurred in the SAPN distribution network only and did not result in the disconnection of any ElectraNet equipment, so is excluded. Including such events would increase the total number of historical faults in each of the time intervals.

This data could indicate a potential risk given the current protection settings of Group D wind turbines allow them to ride through 10 faults within 30 minutes.

AEMO understands that not all the historical faults resulted in the activation of fault ride-through mode by all on-line wind farms. Fault ride-through mode is activated when the wind turbine terminal voltage drops below a certain threshold. The diverse geographical location of these wind farms means that each fault is unlikely to activate fault ride-through mode for all on-line wind farms. It can therefore be concluded that the occurrence of 11 successive faults within 30 minutes is unlikely to result in activation of fault ride-through mode every time for multiple wind farms in this group. Although this does not currently suggest a significant risk from a sustained power reduction perspective, AEMO continues to follow up with the relevant Generators to ensure it has accurate information on the pre-set protection limits of these wind farms on the number of LVRT events within different time periods, and to understand the extent to which these settings can be increased. Of the Group D wind farms, AEMO has not yet received conclusive information on Lake Bonney 1, Starfish Hill, and Wattle Point Wind Farms.

AEMO also notes that a continual increase in the ratio of on-line wind generation to synchronous generation results in a reduction in SA system strength. Operation under reduced system strength scenarios would result in increased severity of the voltage disturbances in terms of the depth, spread, and recovery time following fault clearance for exactly the same voltage disturbance[138], hence a higher likelihood of activating the fault ride-through mode across multiple wind farms.

X.2.2 Simulation results

Simulation case studies were conducted using the PSS/E simulation tool to determine the impact on the Heywood Interconnector's stability, and the risk of islanding, if only one wind farm was unable to ride through multiple faults.

Lake Bonney 1 and Wattle Point Wind Farms were taken as illustrative and plausible examples, due to their unknown capability to ride through multiple faults in quick succession. Simulation case studies were then undertaken with exactly the same conditions set out in Appendix X.1.2 for the 580 MW import level, except the Lake Bonney 1 and Wattle Point Wind Farms were disconnected at the same time as that Snowtown 2 Wind Farms.

Note that scenarios resulting in potential disconnection of any of the SA wind farms due to lack of multiple fault ride-through capability are likely to be caused by non-credible network contingences. However, the resulting voltage disturbances are well within the capability of the wind farms and individual wind turbines, as highlighted in their performance standards.

These studies demonstrate the correct and intended operation of Heywood's loss of synchronism relay due to the loss of more than 400 MW of wind generation and resultant rapidly declining system voltages. This is accompanied by a sharp increase in voltage phase angles relative to HYTS of all major 275 kV substations.

These simulation case studies highlight that it is paramount for all SA wind farms to ride through a sufficient number of voltage disturbances in quick succession, to allow the Heywood Interconnector to stably and securely operate at an import level of 550 MW.

[138] See Figure 34 of AEMO's *2016 National Transmission Network Development Plan*. Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

Disconnection of Lake Bonney 1 wind farm

PSS/E simulation studies

Figure 174 Active and reactive power transfer at Heywood Interconnector

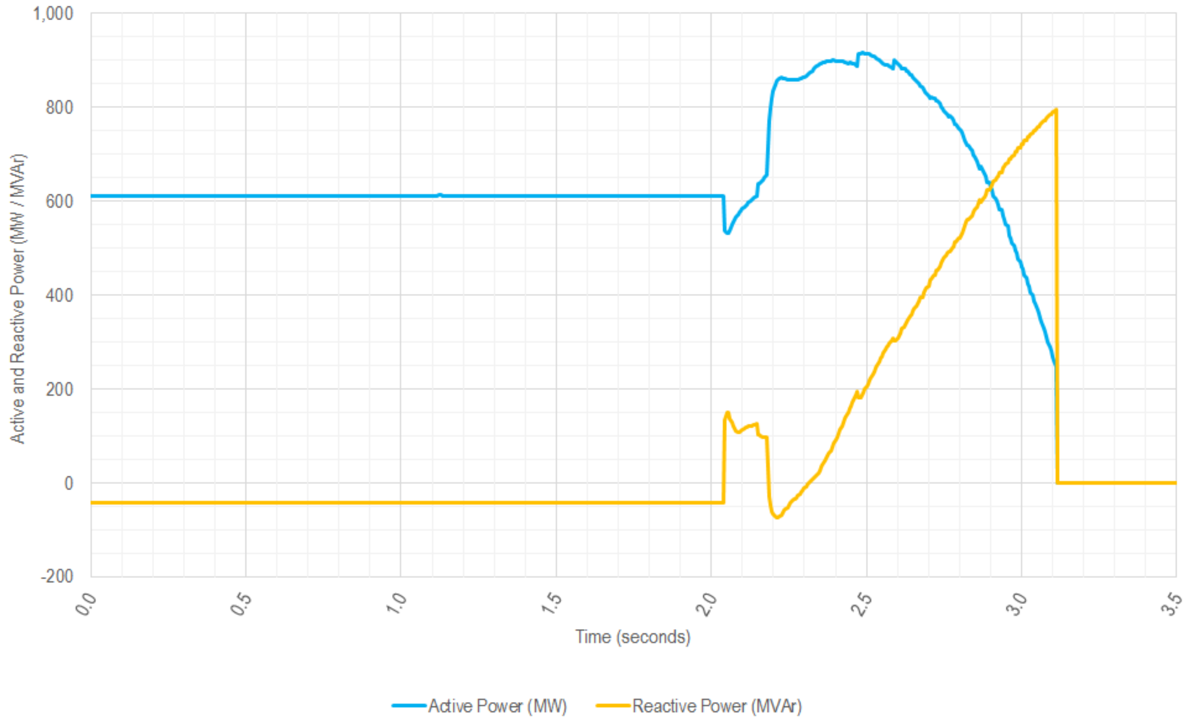


Figure 175 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

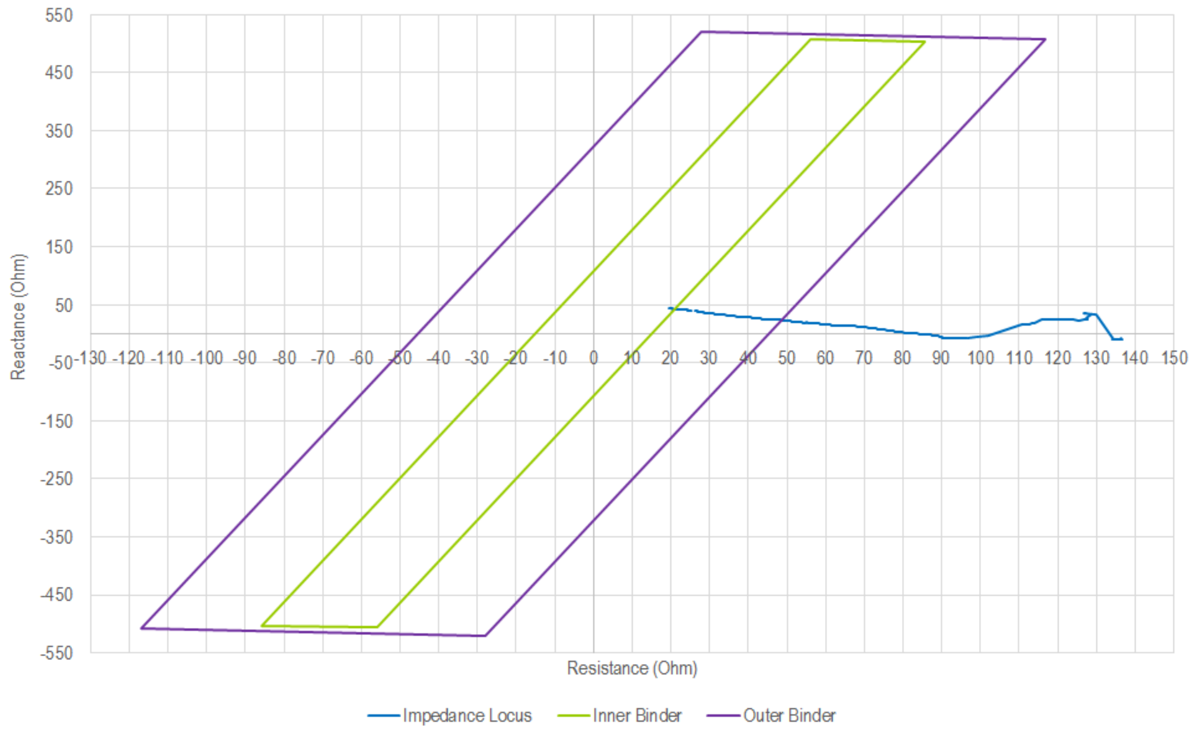


Figure 176 Voltage magnitudes at key SA 275 kV substations

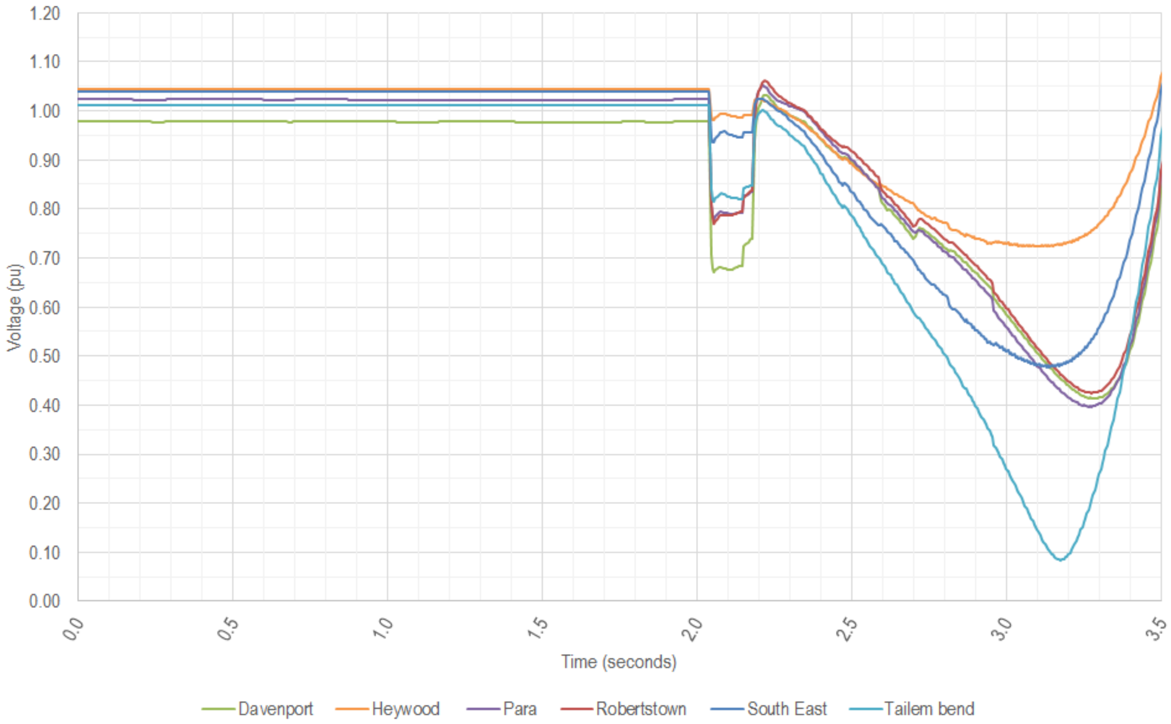


Figure 177 Voltage phase angles relative to HYTS at key SA 275 kV substations

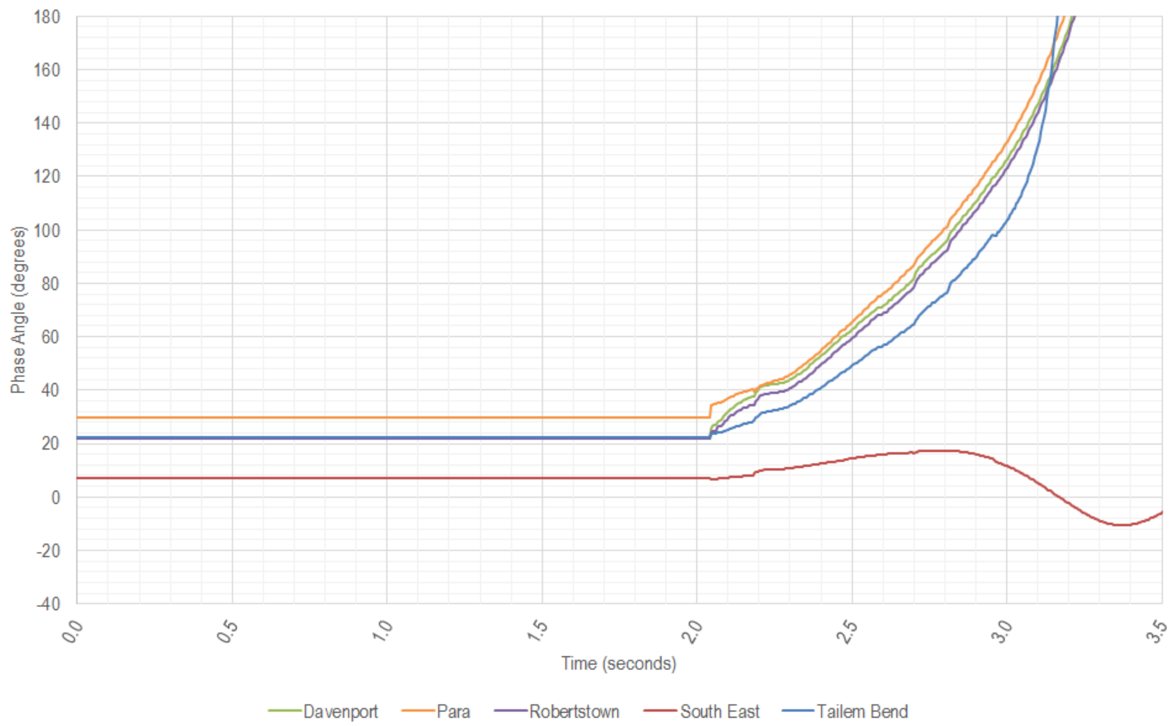
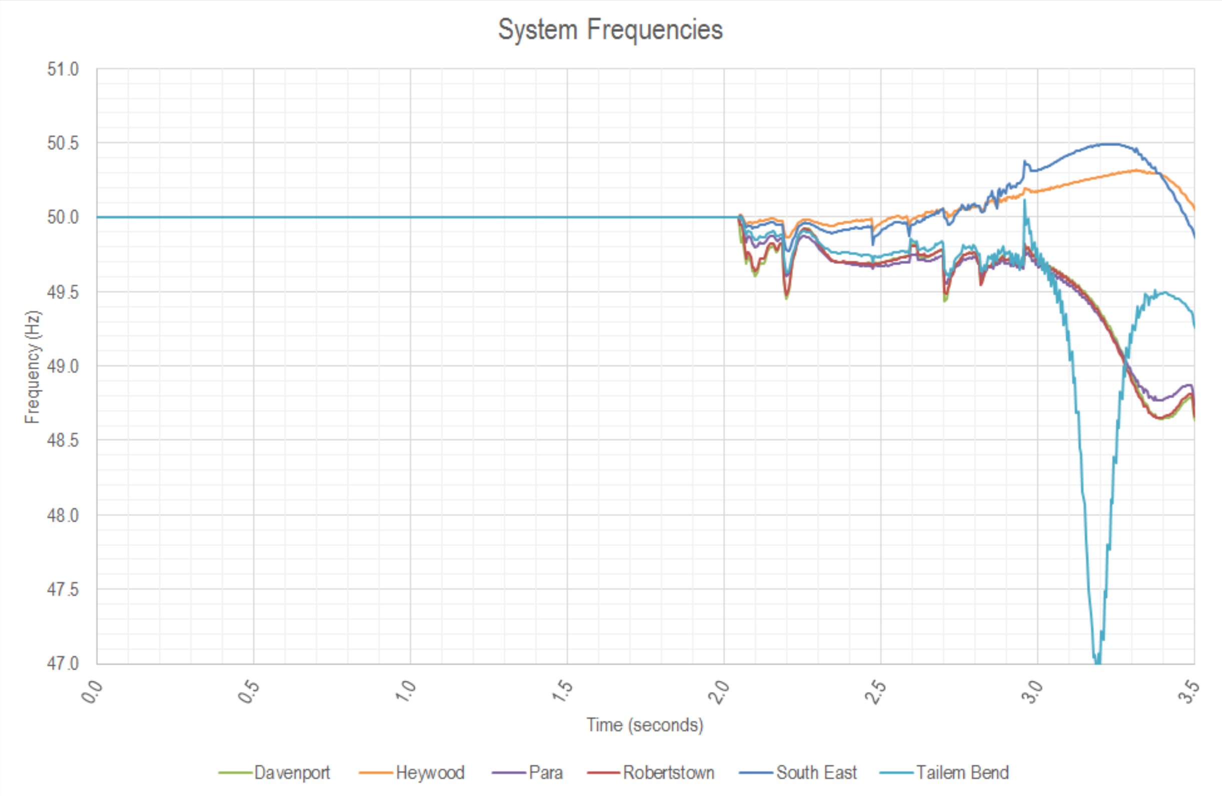


Figure 178 Frequencies at key SA 275 kV substations



Disconnection of Wattle Point wind farm

PSS/E simulation studies

Figure 179 Active and reactive power transfer at Heywood Interconnector

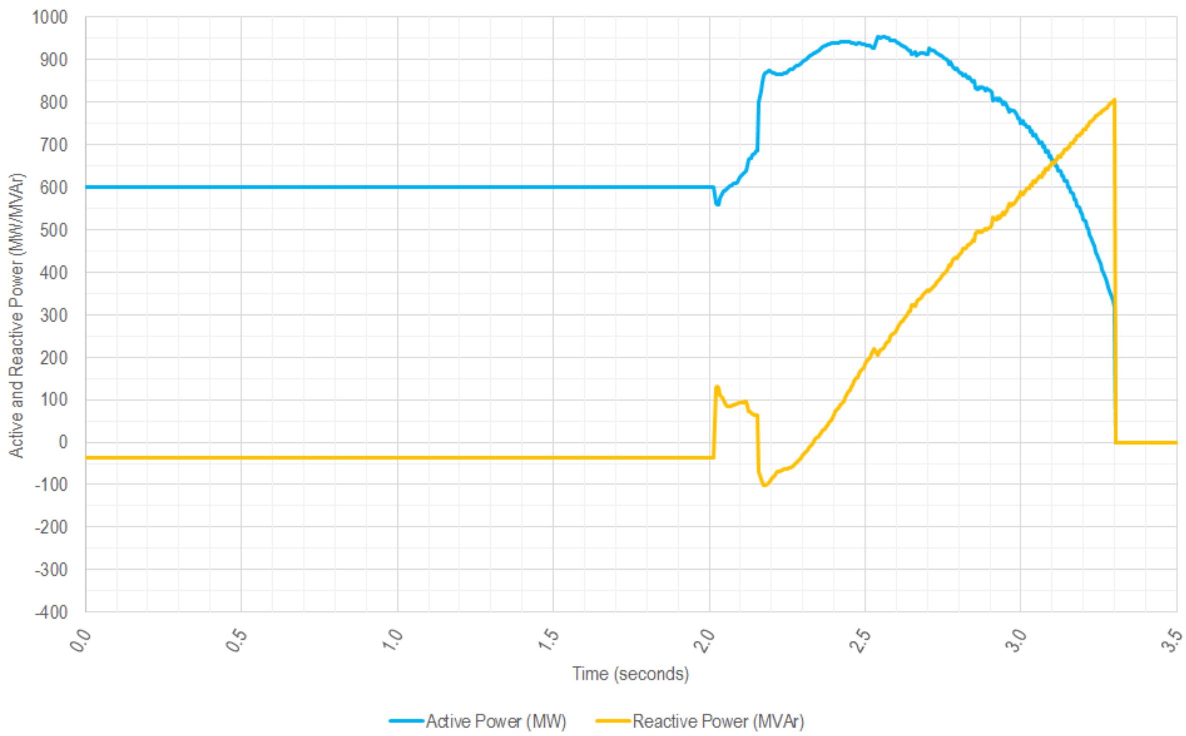


Figure 180 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

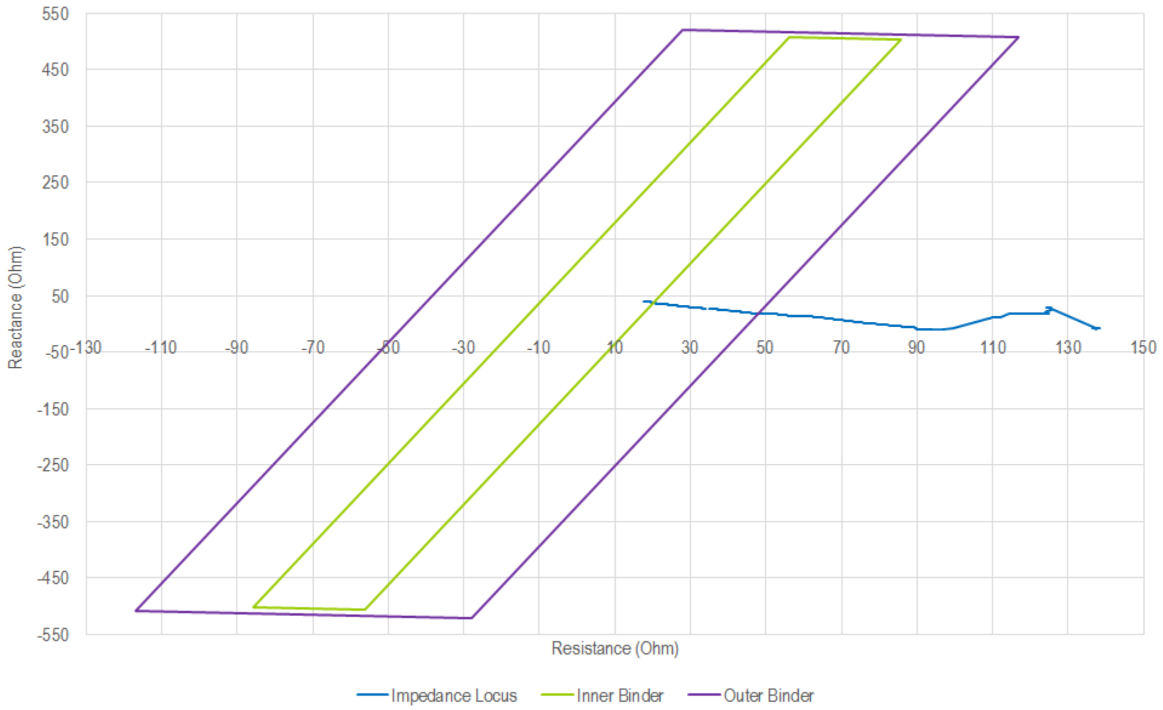


Figure 181 Voltage magnitudes at key SA 275 kV substations

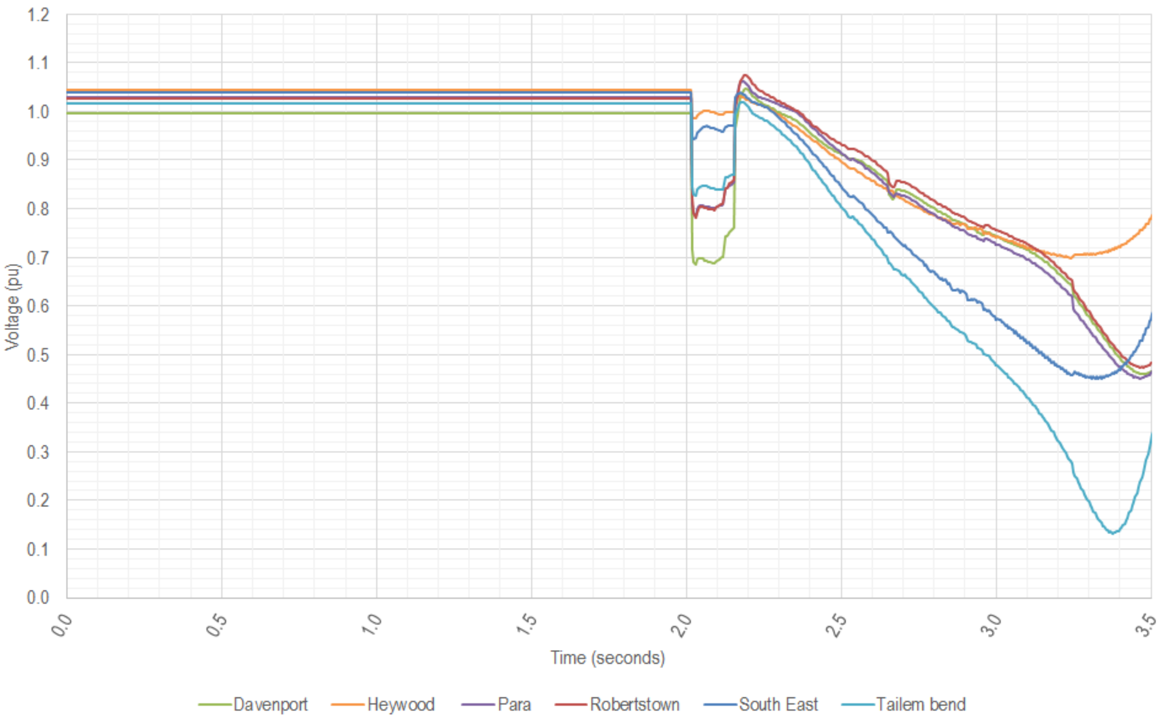


Figure 182 Voltage phase angles relative to HYTS at key SA 275 kV substations

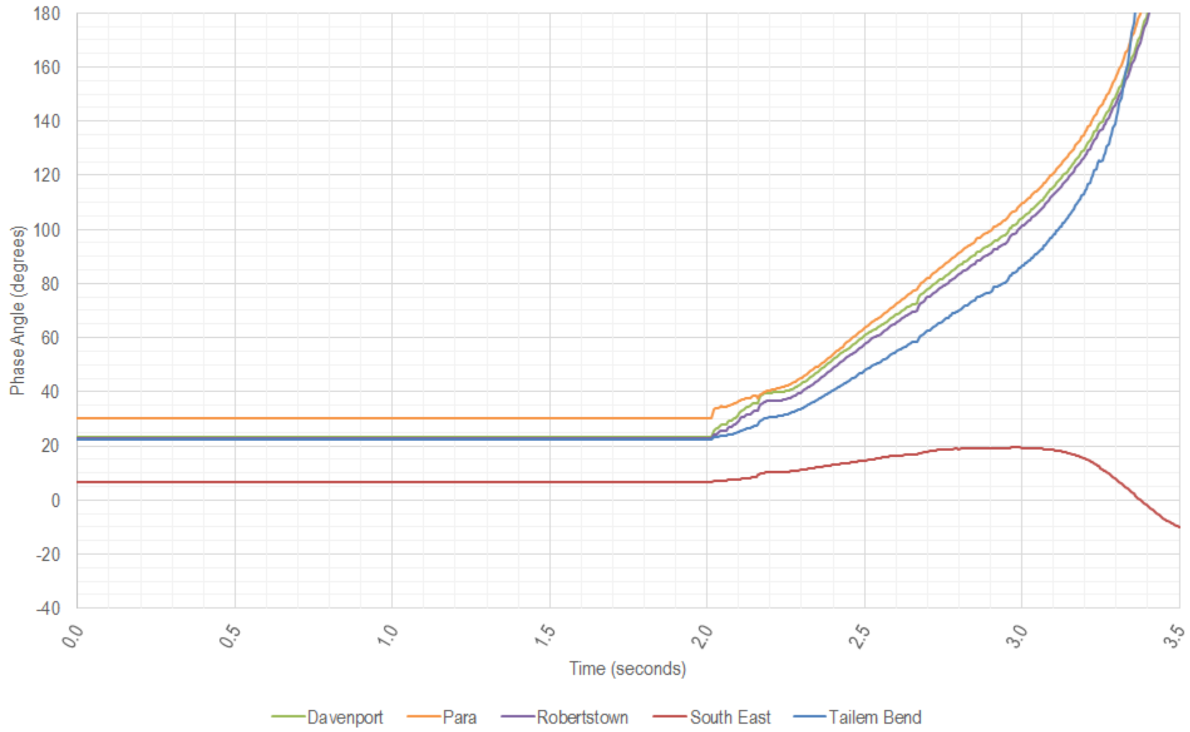
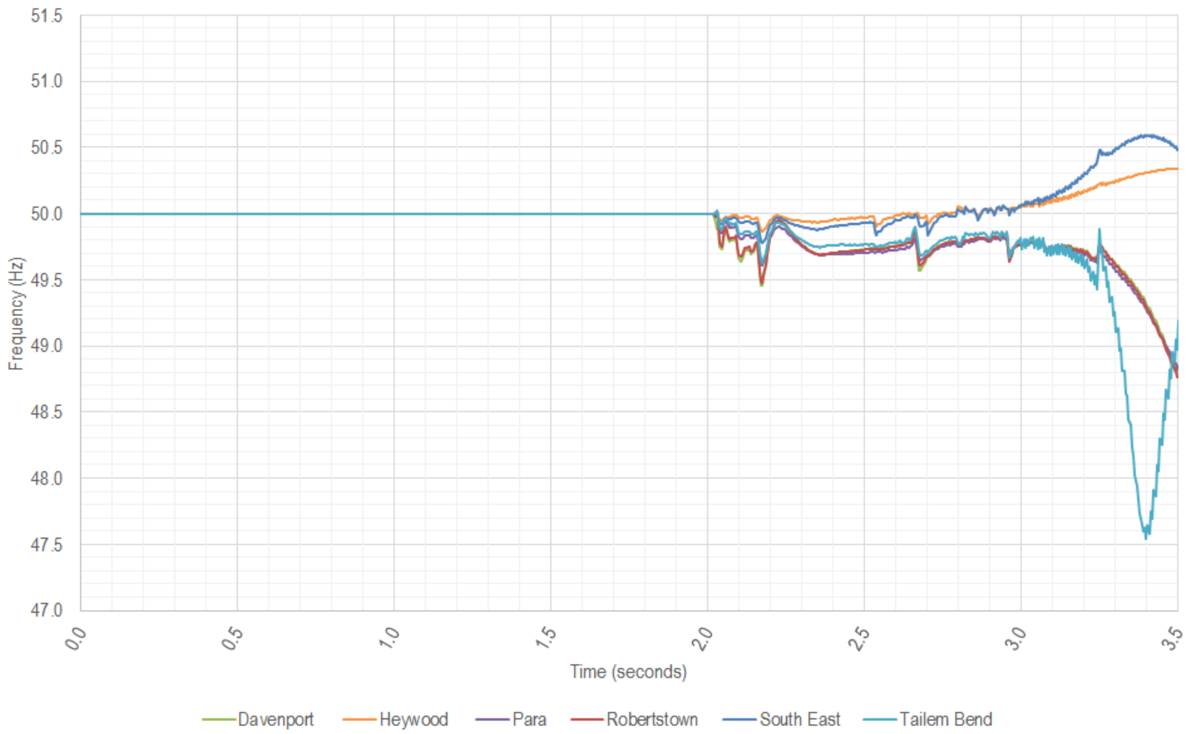


Figure 183 Frequencies at key SA 275 kV substations



X.3 Adequacy of system strength in South Australia during islanded operation

Appendix X.3 evaluates the adequacy of system strength for a number of operating conditions with varying levels of wind and synchronous generation on-line, and during system intact and islanding conditions. The key susceptibility mechanisms investigated include:

- Wind turbines.
- Dynamic reactive power support devices.
- Murraylink HVDC link.
- Protective relays.

X.3.1 Wind turbine generators

Table 27 presents WSCR for all wind farms in SA as a function of:

- Amount of wind generation on-line.
- Combination of synchronous generating units on-line.
- Whether or not the Heywood Interconnector remains connected.

Note that the SA power system currently requires a minimum number of synchronous generating units on-line (equivalent to two TIPS B units). Scenarios studied in Table 27, therefore, reflect higher system strength conditions than the minimum permissible level. However, operation with two synchronous generators can only occur for low Heywood power flow conditions (for example, less than 200 MW), whereas the scenarios discussed in this report primarily focus on high import conditions which necessitate a larger number of on-line synchronous machines.

Appendix X.3.4, which evaluates potential susceptibility of protective relays to low system strength conditions, has accounted for weaker operating conditions with two TIPS B units on-line and loss of the Heywood Interconnector.

Wind farms were grouped based on electrical and geographical proximity to each other as follows:

- Hallett, Hallett Hill, North Brown Hill, and The Bluff Wind Farms.
- Lake Bonney 1, 2, and 3 and Canunda Wind Farm.
- Hornsdale 1 and 2 Wind Farms.
- Cathedral Rocks and Mt Millar Wind Farms.
- Snowtown Wind Farm.
- Snowtown 2 Wind Farms.
- Waterloo Wind Farm.
- Clements Gap Wind Farm.

Starfish Hill and Wattle Point Wind Farms were not considered on-line in the dispatch scenarios studied. These generating systems are located in remote areas and will not be significantly impacted as the SA generation dispatch varies.

Table 27 Short circuit ratio and weighted short circuit ratio calculated for all on-line wind farms

Wind farm	3 TIPS B + Ladbroke Grove (pre-separation)	3 TIPS B + Ladbroke Grove (post-separation)	3 TIPS B + Pelican Point CCGT (pre-separation)	3 TIPS B + Pelican Point CCGT (post-separation)
Clements Gap	10.9	10.8	10.8	10.8
Snowtown	N/A	N/A	6.9	6.9
Snowtown 2	4.3	4.2	2.8	2.8
Waterloo	4.3	4.1	3.9	3.9
Cathedral Rocks	N/A	N/A	1.1	1.1
Mt Millar	2.1	2.1	1.1	1.1

Wind farm	3 TIPS B + Ladbroke Grove (pre-separation)	3 TIPS B + Ladbroke Grove (post-separation)	3 TIPS B + Pelican Point CCGT (pre-separation)	3 TIPS B + Pelican Point CCGT (post-separation)
Hornsdale 1	8.5	8.1	5.4	5.4
Hornsdale 2	N/A	N/A	5.4	5.4
Hallett	3.7	3.5	2.4	2.3
Hallett Hill	3.4	3.3	2.3	2.3
North Brown Hill	3.5	3.3	2.3	2.3
The Bluff	3.7	3.5	2.4	2.4
Canunda	2.6	2.1	1.9	1.6
Lake Bonney 1,2,3	2.6	1.7	1.6	1.4

Comparison of these calculations with the minimum SCR withstand capability of wind turbines, as confirmed by each OEM to AEMO, demonstrates that during the islanding conditions wind turbines installed at the following wind farms would operate below the minimum SCR for which they were designed.

- Canunda.
- Cathedral Rocks.
- Lake Bonney 1, 2, and 3.
- Mt Millar.

Cathedral Rocks and Mt Millar Wind Farms are located in remote areas, and far from any baseload synchronous generation. The combined level of system strength as measured by the WSCR for these two wind farms is generally low, even when the Heywood Interconnector remains connected. To maintain the sufficient level of system strength required for stable operation of these wind farms, it may be necessary to limit their combined output power below that required by ElectraNet's Generation Dispatch Limit (GDL). Further detailed power system studies are required to determine the maximum permissible total output power of these wind farms.

X.3.2 Static Var Compensators

A reduction in system strength can cause oscillations in the SVC reactive power output, due to a voltage regulator gain too high for the reduced system strength.

The following controls currently apply to Para and South East SVCs when operating with reduced system strength conditions:

- Para SVCs:
  - **Gain supervision**: Para SVCs are equipped with an automatic gain supervision feature that ensures stability in the closed-loop voltage control under low system strength conditions. This function reduces the SVC integral gain to 20% of the original value as soon as the fault level at Para Substation drops below 800 MVA as measured at Para Substation.
  - **Gain reduction**: To avoid large voltage oscillations before the gain supervision takes effect, the operator can reduce the gain with a push button. The function is referred to as the 'Black Start Gain' and the gain can be changed between 10% and 90% of the nominal gain.
- South East SVCs:
  - South East SVCs are currently enabled with manual gain reduction capability, which reduces the normal gain by half when enabled by the operator. Automatic gain supervision requiring a further decrease in the gain could be achieved with a software upgrade.
- The minimum design SCR for stable operation of each of the SVCs is 3.

Table 28 shows the calculated SCR at the 275 kV terminals of the Para and South East SVCs, with each of the 2x80 MVAr SVCs bundled as a single SVC. These studies indicate that the available system strength, as measured by the SCR for both the Para and South East SVCs, is well above their minimum design limit, before and after system separation.

The quantity of synchronous generation considered is:

- Three TIPS B + two Ladbroke Grove generating units.
- Three TIPS B + two Pelican Point CCGT generating units.

Table 28 Short circuit ratio calculated for Para and South East SVCs

SVC	3 TIPS B + Ladbroke Grove (pre-separation)	3 TIPS B + Ladbroke Grove (post-separation)	3 TIPS B + Pelican Point CCGT (pre-separation)	3 TIPS B + Pelican Point CCGT (pre-separation)
Para 1+2	16.7	13	23	19.6
South East 1+2	17.8	6.7	17.5	7.38

X.3.3 Murraylink HVDC link

Murraylink HVDC link is located in a remote area, and far from synchronous generation in both SA and Victoria. Because of this remoteness, it has been designed to operate at SCR values down to approximately 1.

For this reason, operation of Murraylink HVDC link is not significantly influenced by the generation dispatch pattern in SA, as shown in Table 29. Operation of the SA power system with low levels of synchronous generation is not, therefore, expected to compromise Murraylink's stability.

Table 29 Short circuit ratio calculated for Murraylink HVDC link

Plant	3 TIPS B + Ladbroke Grove (pre-separation)	3 TIPS B + Ladbroke Grove (post-separation)	3 TIPS B + Pelican Point CCGT (pre-separation)	3 TIPS B + Pelican Point CCGT (pre-separation)
Murraylink	13.1	13.1	6.2	6.3

The reason for a lower SCR for the 3 TIPS B + Pelican Point CCGT dispatch scenario is that the full capacity of 220 MW is used for the calculations, as opposed to 114 MW import level during the Black System. Additionally, Table 29 indicates a slightly higher SCR for this dispatch scenario following system separation, due to the development of temporary over voltages following system separation.

X.3.4 Protective relays

Introduction

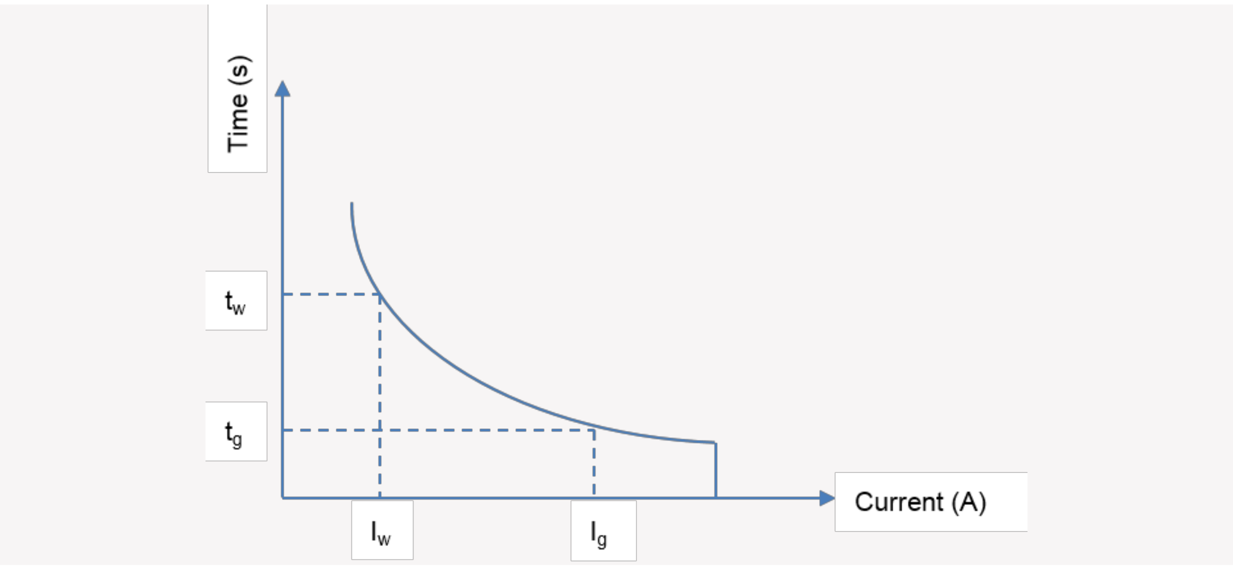
This section:

- Provides general guidance on issues that might be experienced when operating protective relays with lower fault levels than those they are originally designed for.
- Evaluates the mechanisms by which lack of system strength can result in spurious tripping or failure to operate protective relays, and confirms these discussions by performing PSCAD simulation studies for example relays investigated.
- Outlines the fault current calculation studies which were conducted. These studies determine available fault level at all 275 kV and 132 kV transmission lines and busbars, and highlight relays/locations of potential susceptibility.

Over current relays

Figure 184 illustrates the mechanism by which the operation of over-current relays can be adversely impacted as system strength declines. It shows that a lower fault current in weak grids, I_w , would result in a trip delay of t_w, relative to faster time delay of t_g associated with a stronger power system. Prolonged fault clearance under weak grid conditions could result in operation of protective relays in non-faulted zones of protection resulting in excessive disconnection of network and generation elements, or both.

Figure 184 Impact of weak grids on operation of over current relays



Transmission line distance relays

Faults on transmission lines are commonly detected by protective relays, which measure and respond to one or another form of the ratio of voltage to current. This ratio is impedance, or a component of impedance. These relays are called ‘distance relays’ because the measured impedance is proportional to the distance along the line from the relay location to the fault.

A change in the detected impedance is used to determine if a fault has occurred, and also if the fault is in its zone of protection or is elsewhere on the system. This is accomplished by limiting the operation of the relay to a certain range of the observed impedance, commonly called ‘reach’. When a fault occurs within the protected zone of a distance relay, only the faulted transmission line is isolated.

The operating characteristics of these relays are expressed in terms of impedance, or its components, resistance and reactance. Plotted on a rectangular coordinate system (using resistance, R, as the abscissa and reactance, X, as the ordinate), the characteristics usually form simple geometric figures. As an example, the black and red lines in Figure 185 show the characteristics of a commonly used distance relay with two zones of protection.

Distance relays often employ a ‘directional’ element to determine whether each end of the line sees the fault as forward or reverse depending on the function of current flow. This scheme requires information on currents and voltages at both ends of the line. They often use both phase-distance and ground-distance elements, and operate on measurements of zero- and negative-sequence components.

To ascertain the security of distance relays, modern relays are often equipped with an over current pick, whereby current measurements lower than a pre-determined threshold does not result in relay operation.

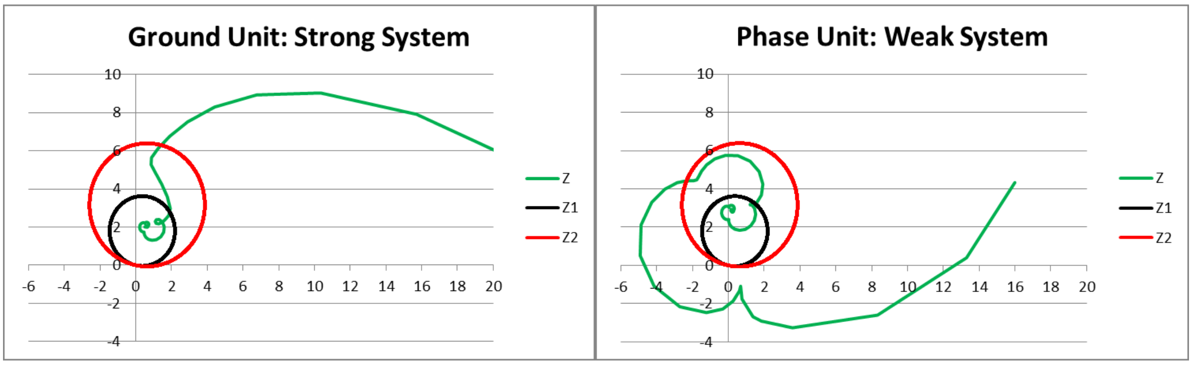
Correct operation of the distance relay would therefore require meeting all three criteria of (i) impedance reach, (ii) fault direction, and (iii) current pick-up (relay operation would be blocked if any of these criteria is not met).

As an example, Figure 185 to Figure 187 demonstrate the impact of system strength on each of these three criteria for a two-phase-to-ground fault.

- **Impedance reach:** System impedance trajectory during fault conditions enters one or both zones of protection (see Figure 185). As an example, Figure 185 shows the ground impedance trajectory for weak and strong network conditions. It can be seen that the end of point of impedance trajectory is located at two different points for weak and strong network conditions. In this case, study fault location is set to 60% of the line distance and Zone 1 reach is set to 80%. Closer inspection reveals that the end point of impedance trajectory in the weak grid exceeds the Zone 1 reach, hence the relay will see the fault in Zone 2 rather Zone 1.

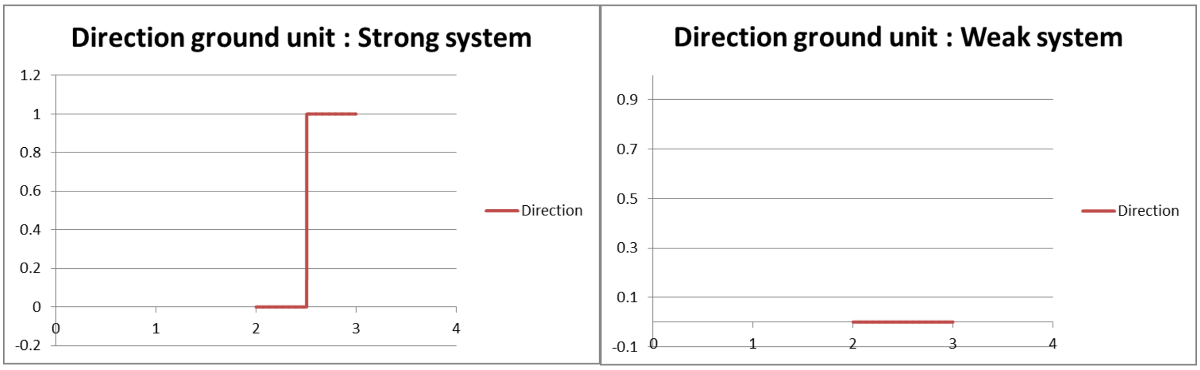
- **Fault direction:** The distance relay directional logic is configured for forward faults in the simulation case studies conducted. This implies that the directional component should give logic "1" for forward faults and logic "0" for reverse faults. Therefore, if the relay identifies a fault as a reverse fault (logic 0), it should block operation for that particular fault. Figure 186 shows when operating in strong grid conditions the correct forward fault direction is detected by the relay. However, weak grid conditions give rise to incorrect reverse fault direction for which relay operation is blocked.
- **Current pick-up:** Current measured by the relay should exceed the pre-determined threshold to ascertain correct operation. Figure 187 indicates operation in a strong network causes the fault current to exceed the threshold. However, operation of the distance relay would be blocked in a weak grid, due to the lack of fault current and inability of the distance relay to detect the fault.

Figure 185 Impact of system strength on impedance trajectory seen by the distance relay during fault conditions



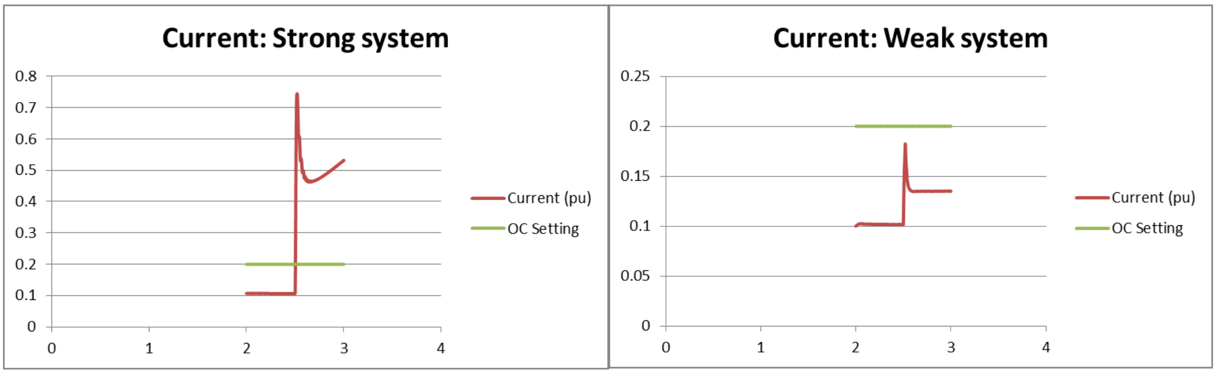
(a) Strong grid (b) weak grid

Figure 186 Impact of system strength on fault direction seen by the distance relay



(b) Strong grid (b) weak grid

Figure 187 Impact of system strength on current level seen by the distance relay



(a) Strong grid (b) weak grid

Fault current calculations

Power system studies were carried out to investigate the impact on the performance of transmission system relays of various generation dispatch scenarios in SA, with and without the Heywood Interconnector.

The following four generation dispatch scenarios have been investigated:

- Scenario 1: Two Torrens Island B generating units.
- Scenario 2: Two Torrens Island B generating units, Heywood Interconnector out of service.
- Scenario 3: Three Torrens Island B generating units, and two Pelican Point CCGT units.
- Scenario 4: Three Torrens Island B generating units, and two Pelican Point CCGT units, Heywood Interconnector out of service.

Figure 188 shows that when the Heywood Interconnector is in service, and with dispatch of five large synchronous generators, 95% of the SA transmission lines would be operating with fault currents greater than 1 pu (winter rating of the lines is considered as the base for per-unitisation).

The following types of transmission system protective relays require a minimum fault current for satisfactory operation[139]:

- Distance protection with over current security function, as described earlier in Appendix X.3.4.
- Busbar protection.

The likelihood of satisfactory operation decreases dramatically where the available fault current drops below 1 pu.

This analysis indicates that with SA islanded, even with three TIPS B and Pelican Point CCGT on-line, there might be a risk to power system security due to potential cascaded tripping, as well as concerns on public safety due to potentially uncleared faults, if the risk is not appropriately mitigated.

Figure 188 also shows that the number of on-line synchronous generators has a marginal impact on the results. This is because the relays with most susceptibility are located in remote areas, and far from the metropolitan region where all the studied synchronous generators are located.

These calculations indicate that with the loss of the Heywood Interconnector there is at least 10% likelihood of an unexpected response of protective relays that could result in cascaded tripping across the system. During islanding conditions, the number of synchronous machines on-line would have a marginal impact on the available fault currents.

AEMO is working with ElectraNet to determine:

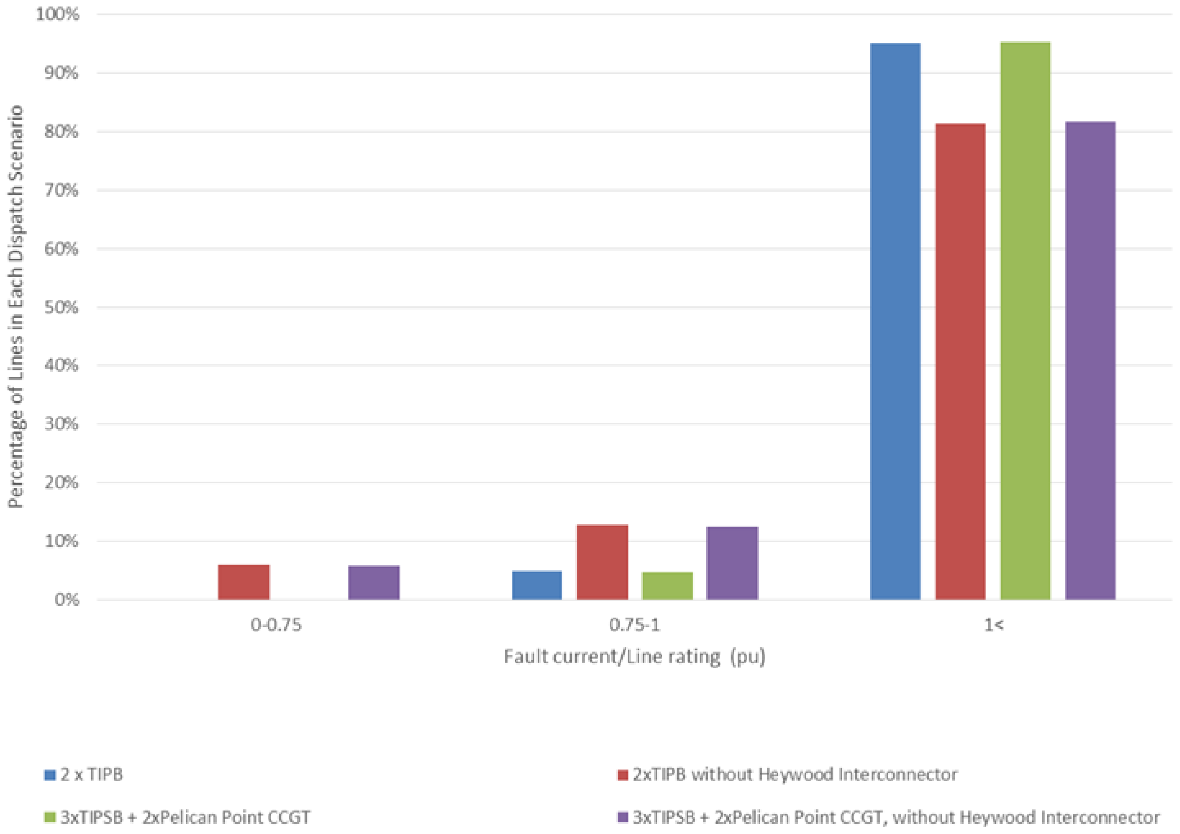
- The precise over current settings of transmission system relays in locations identified as being potentially susceptible.

[139] This infers that the relay operates where it should and does not operate where it should not.

- The extent to which relay settings can be changed without compromising any other aspects of relay performance.

AEMO will conduct further power system studies to determine the extent of residual risk.

Figure 188 Normalised fault currents across SA tranmission lines



X.4 Assessment of the need for changes in technical performance requirements

X.4.1 Ability to ride through sufficient number of voltage disturbances in quick succession

AEMO concludes that the cause of the six voltage disturbances on 28 September 2016 was a non-credible contingency event.

In relation to generator performance standards, however, it is irrelevant whether the event – or the resulting number of faults – were credible or not.

The performance standards applicable to generation in the NEM are developed between the Generator, the connecting NSP, and, in certain circumstances, AEMO.

Schedule 5.2 of the NER contains the criteria used to derive those performance standards. At a high level, Schedule 5.2 details a number of capabilities that generating units and generating systems must demonstrate to effect connection to the network.

There are three levels of capability on which a Generator may seek connection, and they are referred to as ‘access standards’:

- Automatic access standards.
- Minimum access standards.
- Negotiated access standards.

Once they are agreed between all parties, these become the performance standards to which a generating system (or individual generating units, as applicable) must adhere.

Only a few of these performance standards are relevant to the fault ride-through capability.

It is acknowledged that the interpretation of clause S5.2.5.4 in relation to multiple successive voltage disturbances is uncertain, and more problematic in light of the physical operational response of inverter-connected technology compared with thermal synchronous generation.

The performance standard is silent on how many successive disturbances must be ridden through, or how much time can be allowed between each disturbance while maintaining the ride-through capability.

Clause S5.2.5.8 (d) of the NER requires that the conditions be specified for which a generating system or generating unit must trip and must not trip. Inclusion of any limitation to withstand numerous successive disturbance could be included here.

X.4.2 Reactive current injection during voltage disturbances

Introduction

Close inspection of measured responses of wind farms during the Black System, presented in Appendix I.1, indicates unexpected reactive power responses for the following wind farms during fault conditions:

- Hornsdale.
- North Brown Hill and The Bluff.

Typical behaviour of a synchronous generator is that a voltage dip will result in active power reduction, however, reactive power increases to support the voltage during a fault. This is specifically addressed by the automatic access standard in clause S5.2.5.5 (b)(2)(i), which effectively requires capacitive current (reactive power) injection during the fault.

This is not required for either the minimum or negotiated access standard, and a requirement is not specified in the performance standards of the wind farms of concern.

Several international Grid Codes[140] have specific requirements on the reactive power response of non-synchronous generation during and after the faults that require the generating system to inject reactive current into the grid during the fault, irrespective of the control mode in which it was operating before the fault. These requirements also apply to the rise time and response time for the reactive current injection that prevents significant variations in reactive power several hundred milliseconds after the fault.

The performance standards only specify the requirement as for “continuous uninterrupted operation for an event”. The definition of continuous uninterrupted operation in the NER, together with the negotiated access standard in clause S5.2.5.5, imply that the only requirement during an event is for the generating system/unit to not disconnect.

Hornsdale Wind Farm

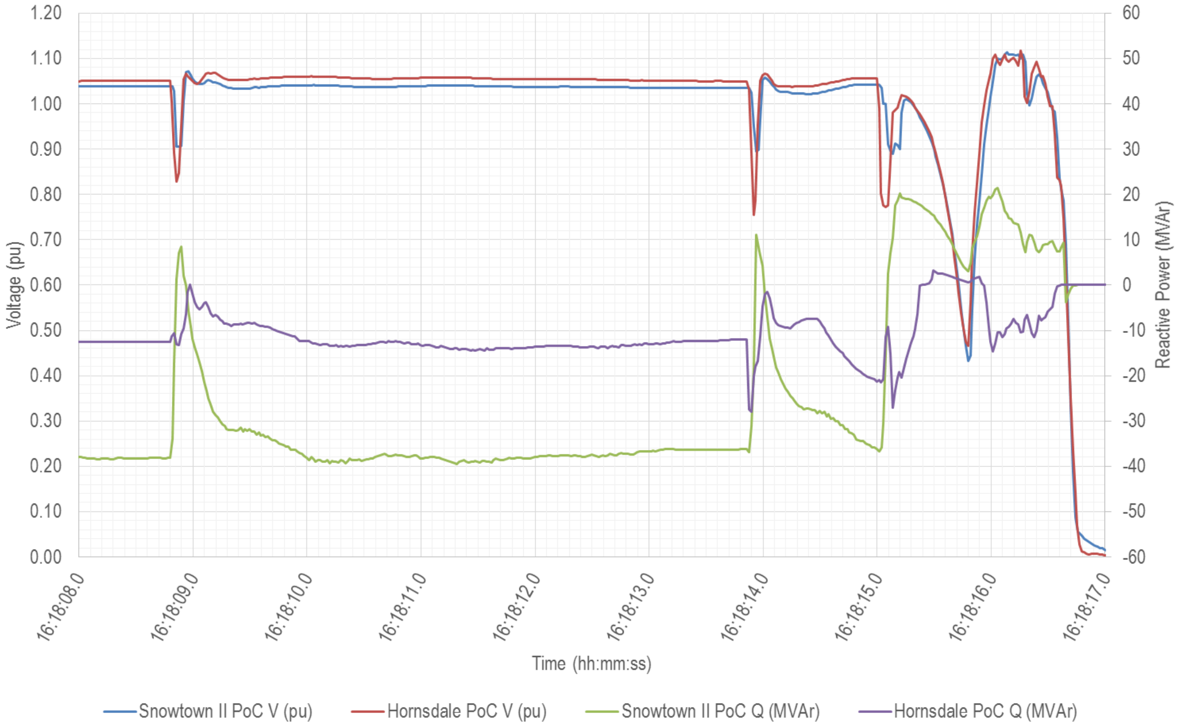
Figure 189 shows that Hornsdale started to absorb reactive power in response to the fault that occurred at 16:18:13.9 on 28 September 2016.

This cannot be attributed to the reverse polarity of current measurements, as the wind farm provided positive and expected reactive current injection for the faults before and after. Comparison of the response of Hornsdale and Snowtown 2 Wind Farms, based on their very similar wind turbine types, indicates positive contribution of the latter wind farm to the same fault. This is despite the fact the connection point voltage at Hornsdale dropped approximately 15% more than that of Snowtown 2.

The size of reactive current injection during fault conditions is a function of the voltage drop at the wind turbine terminals. The larger the voltage drop, the higher the reactive current injection will be, until it reaches its maximum reactive current injection of approximately 1 pu. With this in mind, a larger reactive injection was expected from Hornsdale for the fault that occurred in 16:18:13.9.

[140] Including Danish, German, and Spanish Grid Codes.

Figure 189 Comparison of reactive power responses at Snowtown 2 and Hornsdale Wind Farms



North Brown Hill and The Bluff Wind Farms

Figure 190 presents a comparison of measured reactive power responses at the connection points of Hallett, Hallett Hill, North Brown Hill, and The Bluff.

This indicates that immediately after the fault clearance at 16:18:08.9, North Brown Hill started to consume reactive power from the network with a peak value of -50 MVAr. It also exhibited significant variations in the reactive power for approximately 500 ms after the fault clearance.

Closer inspection of this response reveals that the dynamic reactive support plant for North Brown Hill were measuring currents with the reverse polarity, as shown in Figure 191.

Note that the actual dynamic reactive support plant were injecting reactive power into the network. The Generator has confirmed that the reverse polarity has been rectified since then.

The negated response of these devices is also shown in Figure 191. The reactive power consumption immediately after the fault cannot, therefore, be attributed to the response of dynamic reactive support plant.

Figure 190 Comparison of reactive power responses at the connection point of the Hallett, Hallett Hill, North Brown Hill, and The Bluff wind farms

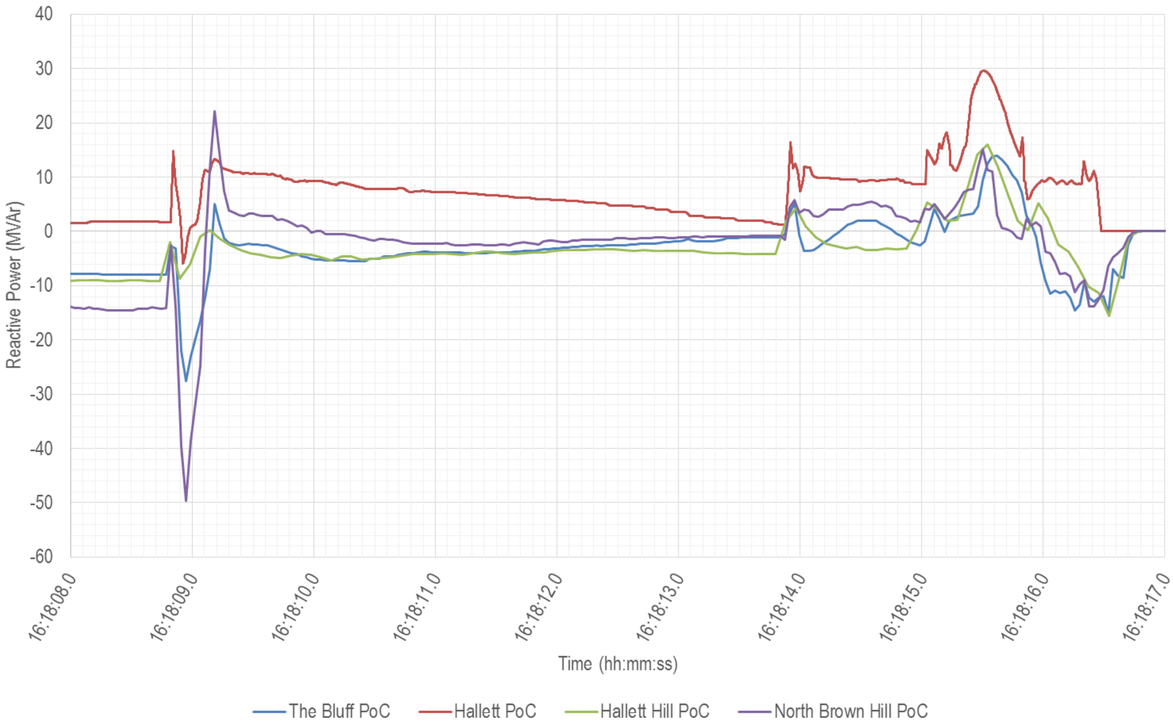
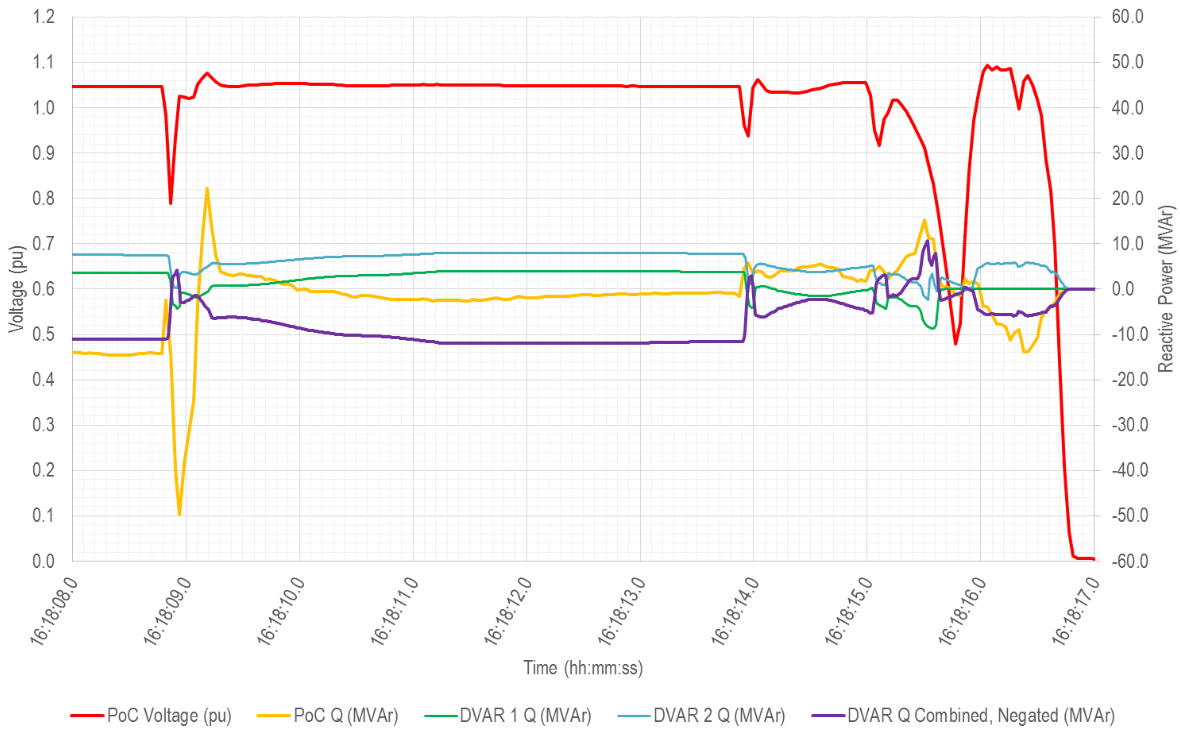


Figure 191 Comparison of reactive power responses at the connection point and that provided by the dynamic reactive support plant



In addition to North Brown Hill, excessive reactive power variations are visible at The Bluff. While the magnitude of these variations is smaller than those of the North Brown Hill, it constitutes a larger percentage of installed capacity for The Bluff, considering that its installed capacity is 40% of that of North Brown Hill.

Conclusions

While these performances were unexpected, generator performance standards do not include detailed requirements for reactive power response.

AEMO will propose that ESCOSA consider including more specific requirements on the reactive power response of wind farms in the revised versions of ESCOSA licensing conditions, allowing improved response of wind farms during and after the fault.

AEMO will include similar recommendations in a Rule change proposal for requirements on the reactive power response of all generators.

Further, AEMO will request the relevant Generators to precisely define the reactive power response during and subsequent to faults when negotiating any future generator performance standards.

X.4.3 A requirement for enhanced high voltage ride-through capability

Temporary over voltages can occur in the SA power system under the following operating conditions:

- Loss of the Heywood Interconnector.
- Significant amount of load shedding.

The combination of the two would further exacerbate the situation. Simulation case studies reported in Appendices Y.4 and Y.5 show high temporary over voltages developing, even when the Heywood Interconnector remains intact. These studies also indicate disconnection of a number of wind farms and one synchronous generator due to their over voltage protection settings.

Comparison of Figure S5.1a.1 of the NER (which sets out the automatic access standard for generating systems' over voltage withstand capability) with corresponding requirements in other Grid Codes, such as ENTSO-E and Hydro Quebec Grid Codes, indicates that the NER requirements are towards the lower range.

AEMO's assessment of the capability of a number of major wind turbine and solar inverter manufacturers also reveals that the over voltage withstand capability of state-of-the-art wind turbines and solar inverters can exceed or far exceed the current NER requirements.

AEMO will propose that ESCOSA consider more specific requirements for enhanced HVRT capability of wind farms in the revised versions of ESCOSA licensing conditions and will propose appropriate changes to the NER.

APPENDIX Y. INVESTIGATIONS OF CONTROL AND PROTECTION SCHEMES

This Appendix has been added to this final report.

Y.1 Introduction

Appendix Y investigates the feasibility of a number of additional control and protection schemes, not currently in place in the SA power system, to assist in maintaining the integrity of the Heywood Interconnector in response to major loss of generation events in the SA.

When considering the operation of loss of synchronism protection at the Heywood Interconnector, the following factors must be considered:

- It is the rate of change of impedance that predominantly determines whether the loss of synchronism relay operates. A fast rate of change of impedance implies fast increase in Interconnector's active power flow at the same time as a rapid decline in the SESS voltage.
- Increase in Heywood Interconnector flow alone, due to non-credible loss of generation in SA, does not result in angular instability and loss of synchronism so long as voltages are maintained across the system, and most importantly at the SESS. The dynamic voltage decline is not the cause of angular instability and system separation, however it plays a part in determining system stability.
- Events resulting in slow changes in the currents and voltages as seen by the Heywood Interconnector are less likely to drive the impedance trajectory to enter the loss of synchronism relay characteristic area. Such events may include localised generation reduction/disconnection, for example, the event which occurred on 3 March 2017, which resulted in loss of three TIPS B and Pelican Point units.

These points are corroborated by Figure 192, which shows the Heywood Interconnector's active power flow and voltage for the 3 March 2017 event, based on SCADA data. This figure highlights a peak import level of 960 MW across the Heywood Interconnector, which is higher than that for all five relevant historical system separation events for which the loss of synchronism relay operated.

However, for the 3 March 2017 event, voltages at the South East area momentarily dropped to a minimum of 0.88 pu and recovered immediately thereafter. The high current by itself could not therefore result in loss of synchronism.

Figure 193 indicates that the impedance trajectory during this event was far from the relay characteristic area. The loss of synchronism relay therefore correctly blocked operation for this stable power swing.

Figure 192 Heywood Interconnector's active power flow and voltage for the 3 March 2017 generation disconection event in SA

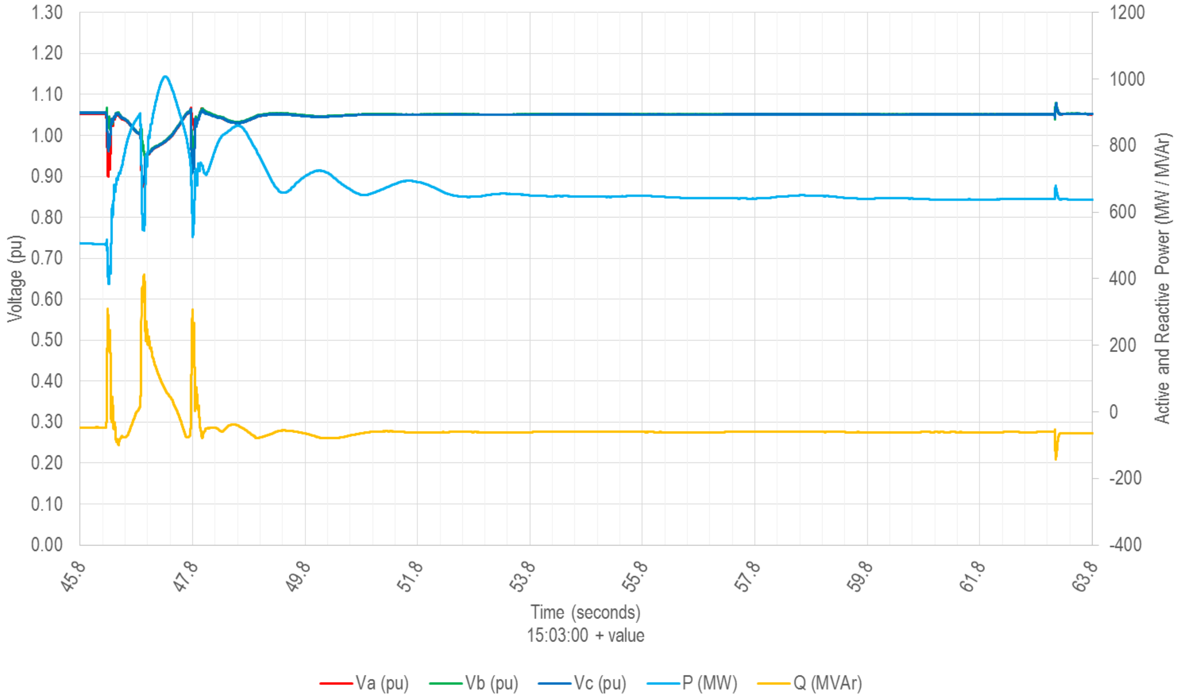
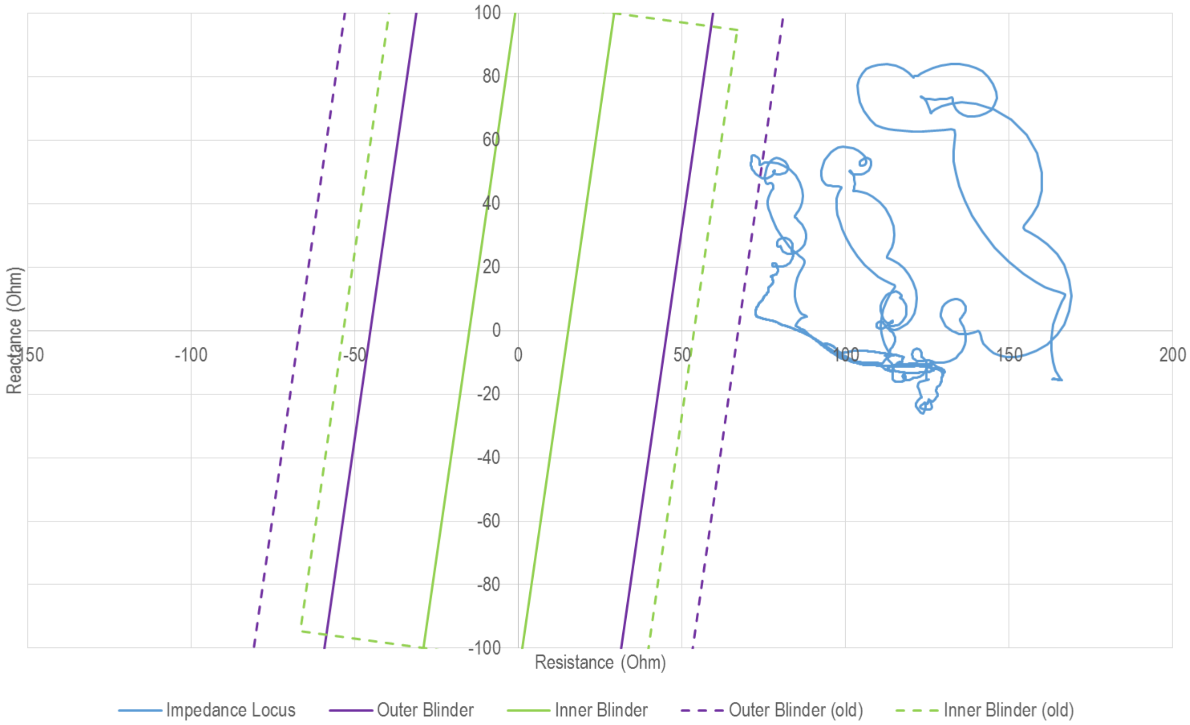


Figure 193 Impedance trajectory seen by the Heywood loss of synchronism relay for the 3 March 2017 generation disconection event in SA



Y.2 Factors that need to be considered when designing a load shedding scheme

Y.2.1 Supply demand balance management

SA power system stability, following loss of the Heywood Interconnector, is currently managed by the conventional UFLS scheme.

However, it is becoming increasingly foreseeable that the UFLS scheme will not work for non-credible loss of generation events, such as the event on 28 September 2016. It did not work on that occasion because the frequency did not drop sufficiently to activate the conventional UFLS scheme prior to the system separation. This is expected to be the case for any potential future separation events, because the rest of the NEM will maintain the system frequency, including that measured in SA.

Any enhanced load shedding scheme would therefore need to act on network parameters which reflect the state of the 'health' of the power system more quickly than the system frequency, and initiate as soon as conditions indicating near instability are detected.

This is addressed in Appendix Y.3 to Y.5, which consider the feasibility and effectiveness of load shedding based on both pre-emptive (pre-separation) and post-separation SPSs, primarily focusing on stabilising the system following the rapid loss of a significant amount of generation.

AEMO notes that if an SPS with faster speed of response and larger amount of load shed is unable to stabilise the system, any enhancements that could be achieved within the limits of conventional UFLS scheme (in terms of larger allocation of load blocks, or faster speed of response) would not provide any tangible value.

It is important to recognise that the issue of supply demand balance management cannot be considered in isolation. Any solutions to arrest the frequency following system separation would need to account for the severity of temporary over voltages and the adequacy of system strength, as discussed below.

Y.2.2 Temporary over voltages following system separation

All five relevant historical SA separation events resulted in over voltages of up to 1.2 pu immediately after the islanding, which lasted for several seconds (see Appendix K).

When designing a load shedding scheme, whether it is based on UFLS or SPS, there is a trade-off between the amount of load shed, and the level of resulting over voltages.

This is because the majority of loads comprise both active and reactive components. Load shedding would therefore result in the reactive power demand falling below the reactive power generation, which causes temporary over voltages.

The three critical factors that need to be considered when assessing temporary over voltages include:

- Over voltage withstand capability of wind farms and synchronous generators.
- Time delays for connection of out-of-service shunt reactors and disconnection of in-service shunt capacitors. These time delays are generally in the order of 5–10 seconds. Smaller time delays (in the range of a few hundred ms) have been discussed in technical literature to assist in the formation of viable islands as part of SPSs.[141]
- Any instantaneous/fast over voltage protection in the transmission or distribution network with time delays less than 1 second.

Series capacitors at Black Range Terminal Station are bypassed following system separation, and would not therefore need to be considered as part of the management of temporary over voltages following system separation.

[141] See references in Appendix Y.4.1.

Y.2.3 Adequacy of system strength

The significance of maintaining system strength in the SA power system, particularly under islanding conditions, was discussed in X.3. The SCR/WSCR calculations presented in Table 28 indicate the susceptibility of a number of wind farms following loss of the Heywood Interconnector.

Time-domain studied discussed in Appendices Y.4 and Y.5 confirm a higher possibility of disconnection for wind farms with low SCR following islanding. Disconnection of a number of wind farms due to rapidly changing voltages across the SA power system immediately after system separation could invalidate the supply-demand balance achieved through a load shedding scheme.

Y.3 General requirements for special protection scheme

Table 30 presents a number of possible SPSs that can assist in stabilising the SA power system for SA import conditions and the loss of several hundred MW of wind generation. ‘Traffic-light’ colour coding is used to show the contribution of each potential solution to:

- Avoiding system separation following major loss of generation in SA.
- Ensuring the formation of a viable and stable island following separation.

The ‘traffic-light’ colour coding can be interpreted as:

- Green: High contribution.
- Yellow: Potential contribution.
- Red: Unlikely contribution.

Table 30 Possible special protection schemes for Heywood import conditions and loss of several hundred MW of generation

Special protection scheme	Effectiveness to avoid SA system islanding	Effectiveness to stabilise the SA island	Comments
Under frequency load shedding			• The frequency does not drop sufficiently pre-separation to activate the UFLS. • The effectiveness of post-separation UFLS is highly dependent on temporary over voltages and system strength.
Under voltage load shedding			• Following system separation over voltages occur across the system rather than under voltages.

Fast pre-emptive load shedding		N/A	• Has the following advantages to the UFLS:
			  • Faster speed of response.
			  • Larger amount of load shed (if necessary).
			  • Act on quantities that predict the system health better.

HVDC fast power change			• Not possible with current design of Murraylink HVDC link.
Automatic shunt capacitor/reactor switching			• Crucial for management of temporary over voltages following islanding. • Should be considered when applying pre-emptive load shedding which causes temporary over voltages even before system separation. • Not many shunt capacitors may be on-line to switch out.
Transformer Tap changer blocking			• Less useful than ''automatic shunt capacitor/reactor switching'' due to slower speed of response.
Formation of small intentional islands	N/A		• Formation of small viable islands, e.g. around Adelaide Metropolitan, has not been considered in this report.
Fast frequency control			• This refers to fast, e.g. <1 s, frequency control compared to 6 s contingency FCAS currently in place. • Limited contribution prior to the system separation due to small changes in frequency. • Cannot work in isolation but can be used along with the load shedding. • Even a 1 s response post-separation would likely be slow. • Advantage to load shedding is that it only varies the MW and not MVAr.

Y.4 Feasibility of an SPS to prevent system separation

Y.4.1 Introduction

This section discusses the feasibility of a pre-emptive SPS enabled load shedding scheme.

As an example, for demonstrating the effectiveness of the SPS, voltage phase angle is used to initiate the load shedding. In this example, the load shedding starts to act as soon as the voltage phase angle difference between the Heywood and Para exceeds 60 degrees.

The load shedding is considered to comprise three stages of 200 MW, each delayed by 100 ms. It is assumed that the first stage takes effect in 100 ms. Note that the 100 ms action time is towards the high end of what can be achieved with today's technology.[142,143] AEMO considered such a fast action time to understand the maximum contribution of an SPS.

The following sub-sections evaluate the contribution of such an SPS for the generation dispatch, during the Black System event, and with a higher inertia system with three TIPS B and Pelican Point CCGT units.

Studies reported in this section demonstrate that an SPS-enabled load shedding is effective in preventing SA islanding conditions due to non-credible loss of generation, and that the level of load shedding can be judiciously chosen to avoid temporary over voltages across SA.

Y.4.2 Ability of an SPS to prevent system separation on 28 September 2016

The scenario discussed in this section is a variation of that presented in Appendix W.3.2. It has been modified so 600 MW of load is shed after the clearance of the six voltage disturbances, and as soon as the relative voltage phase angle between the Heywood and Para Substations reaches 60 degrees.

This is shown in Figure 194, which highlights the originally unstable voltage phase angles, and the time at which the three load blocks of 200 MW each were shed as implemented in the simulation model accounting for the 100 ms delay for each stage.

Over voltages are experienced across the SA power system immediately after the load shedding due to disconnection of both active and reactive components of the loads. This results in disconnection of the following generating systems due to their over voltage protection settings[144]:

- Canunda Wind Farm
- Lake Bonney 1, 2, and 3 Wind Farms.
- Hallett Wind Farm.
- Hallett Hill Wind Farm.
- The Bluff Wind Farm.
- North Brown Hill Wind Farm.
- Ladbroke Grove Power Station.

Most wind turbines associated with the Hallett, Hallett Hill, North Brown Hill, and The Bluff Wind Farms were already disconnected on other mechanisms (including limited capability to ride-through multiple faults), and on high wind speed disconnection. Also, all on-line wind turbines at Clements Gap Wind Farm were disconnected before 16:18:15 and were therefore not on-line after the six voltage disturbances where the SPS is considered to respond.

[142] A. Heniche, I. Kamwa and M. Dobrescu, "Hydro-Québec's defense plan: Present and future," 2013 IEEE Power & Energy Society General Meeting, Vancouver, BC, 2013, pp. 1-5.

[143] J. Sykes, M. Adamiak and G. Brunello, "Implementation and Operational Experience of a Wide Area Special Protection Scheme on the SRP System", *2006 Power Systems Advanced Metering, Protection, Control, Communication, and Distributed Resources*, Clemson, SC, 2006, pp. 145-158.

[144] A less aggressive SPS-enabled load shedding, e.g. shedding 200 MW of load, would have reduced the extent of generation disconnection due to temporary over voltages. However, the resulting post-event Heywood Interconnector flow would have been in the range of 900–1,000 MW, which is not considered viable to operate over several minutes.

However, the Canunda and Lake Bonney 1, 2, and 3 Wind Farms, and Ladbroke Grove Power Station were operating at high output power and disconnected due to high temporary over voltages.

The remaining load of approximately 1,200 MW in the SA power system would therefore by supplied by:

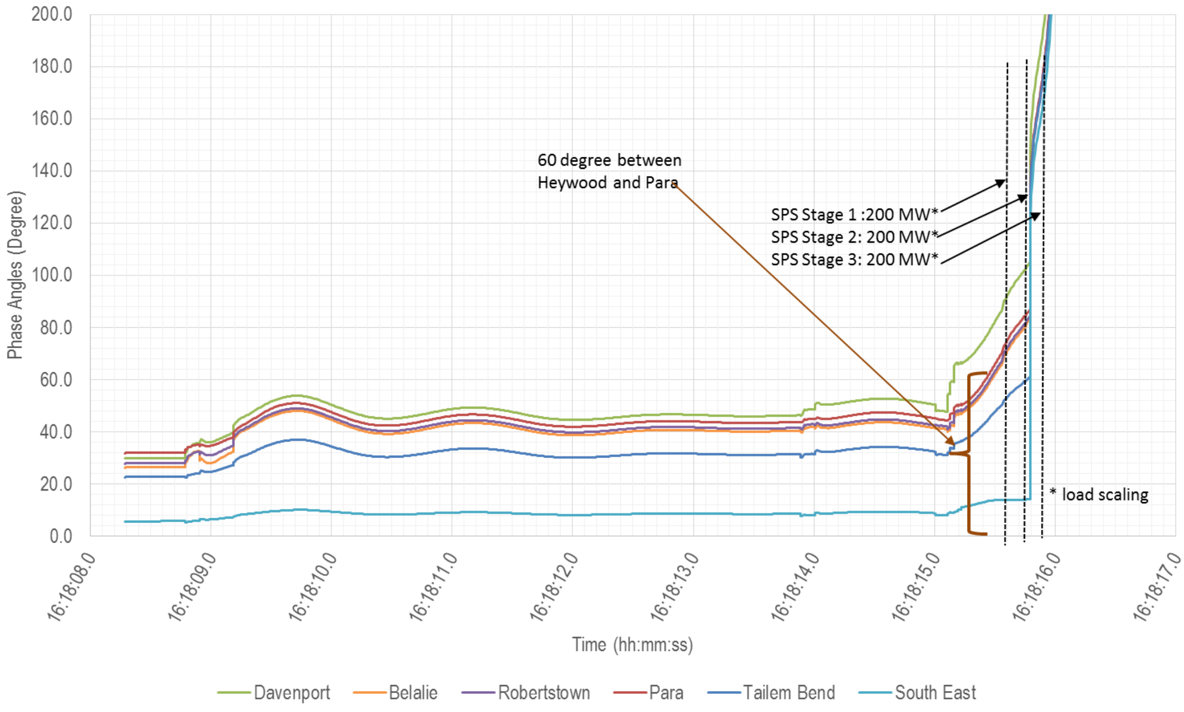
- Heywood Interconnector.[145]
- Murraylink HVDC link.
- TIPS B1, B3, and B4.
- Waterloo Wind Farm.

Figure 195 indicates a transient peak of approximately 1,100 MVA on the Heywood Interconnector, which is well within the 15-minute short-term rating of approximately 1,500 MVA for the two circuits.

Figure 196, Figure 197, Figure 198, and Figure 199 indicates the stable response of the SA power system, and that the impedance trajectory would not have entered the loss of synchronism operating area. Note that Figure 196 is based on the loss of synchronism relay characteristic which was in service at the time of the Black System. The new loss of synchronism relay currently in service has a narrower characteristic around the R-axis compared to the previous relay settings.

PSS/E simulation studies

Figure 194 Voltage phase angles relative to HYTS at key SA 275 kV substations without SPS



[145] Note that Heywood interconnector would be initially operating above its secure limit, and dispatch of further generation would be required to return the flow to its secure limit within 30 minutes.

Figure 195 Active and reactive power transfer at Heywood Interconnector with SPS

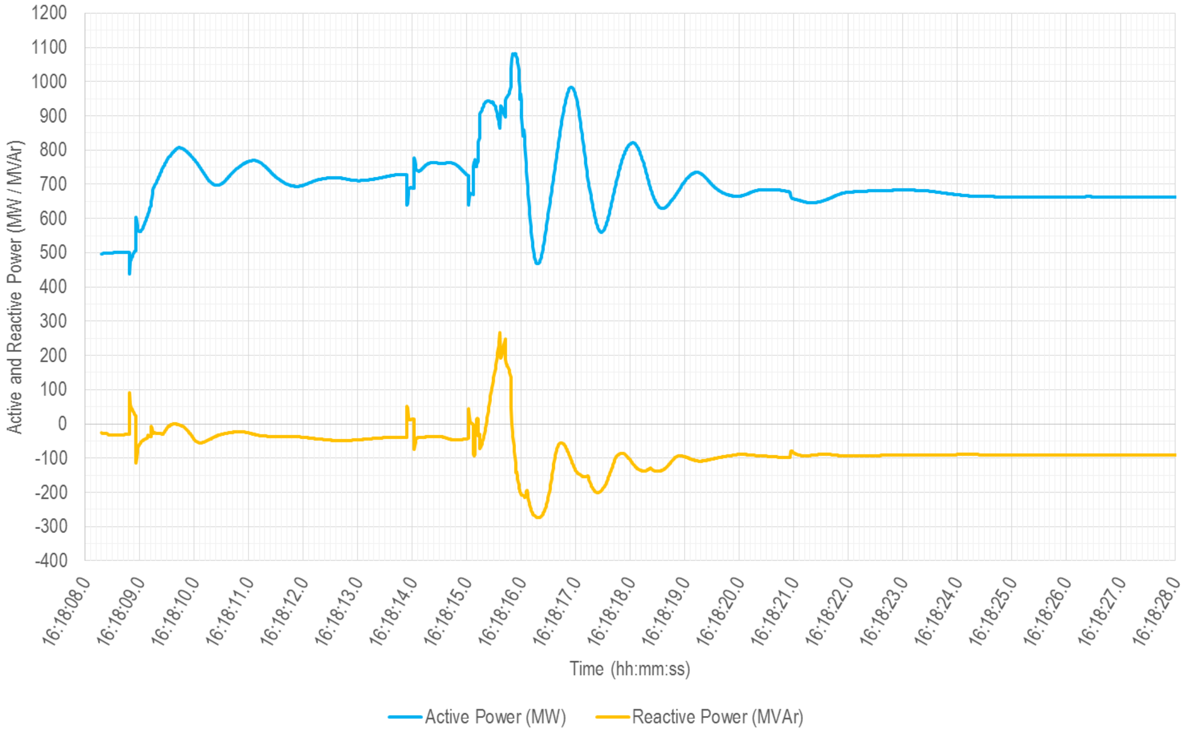


Figure 196 Simulated impedance trajectory at Heywood Interconnector with SPS against relay characteristic area

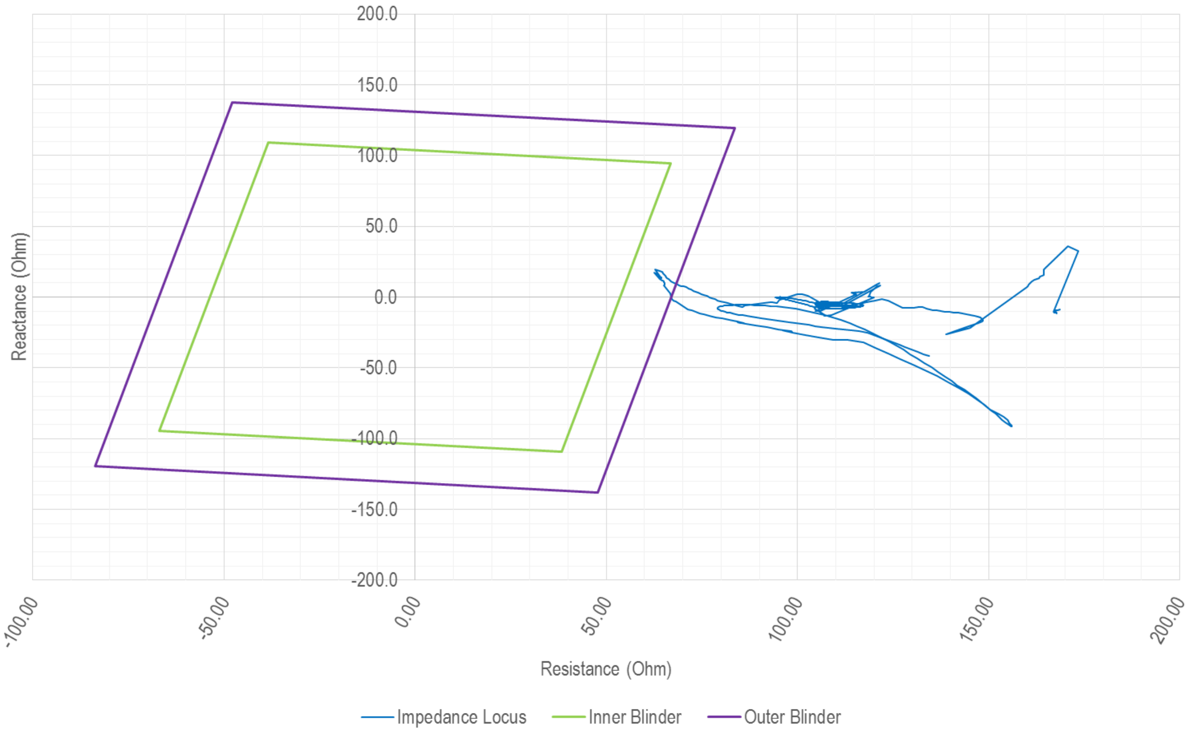


Figure 197 Voltage magnitudes at key SA 275 kV substations with SPS

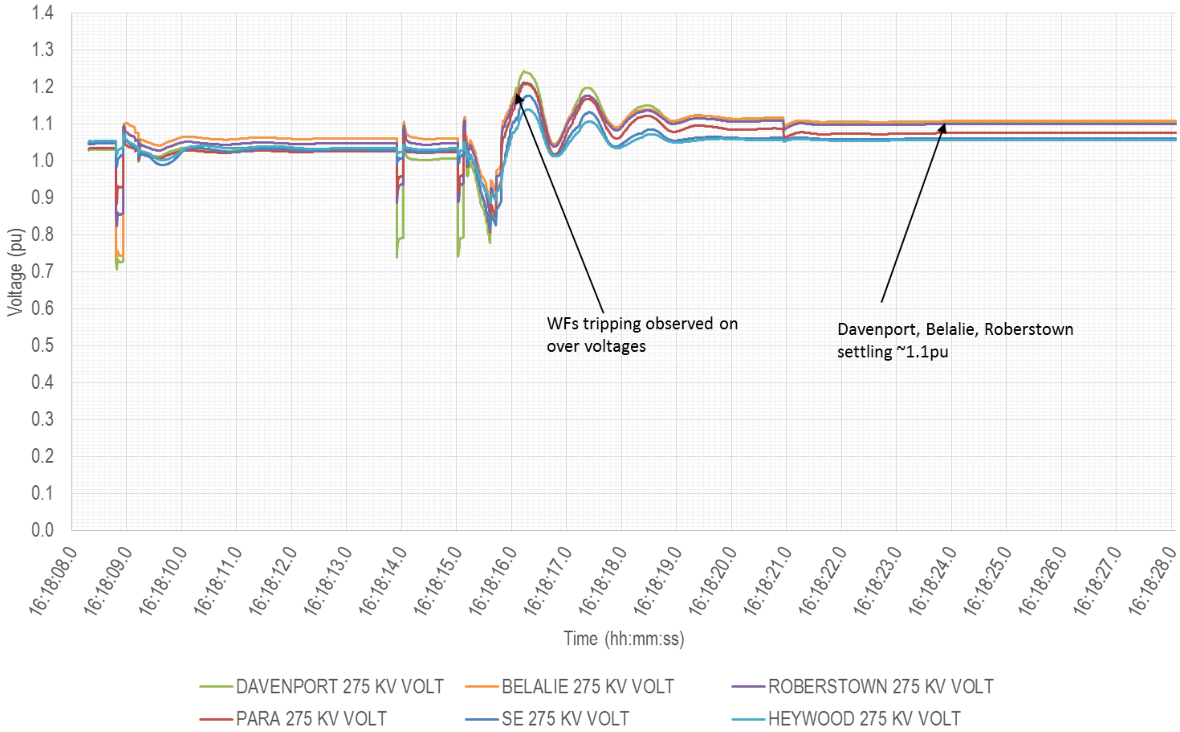


Figure 198 Voltage phase angles relative to HYTS at key SA 275 kV substations

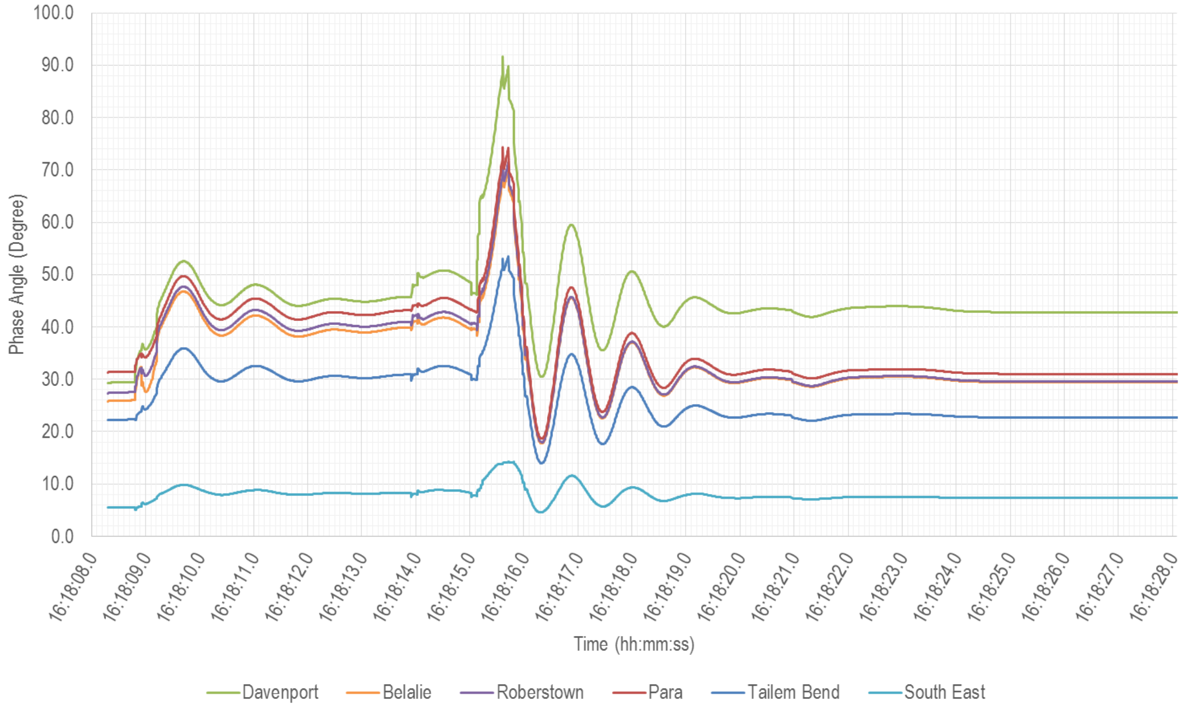
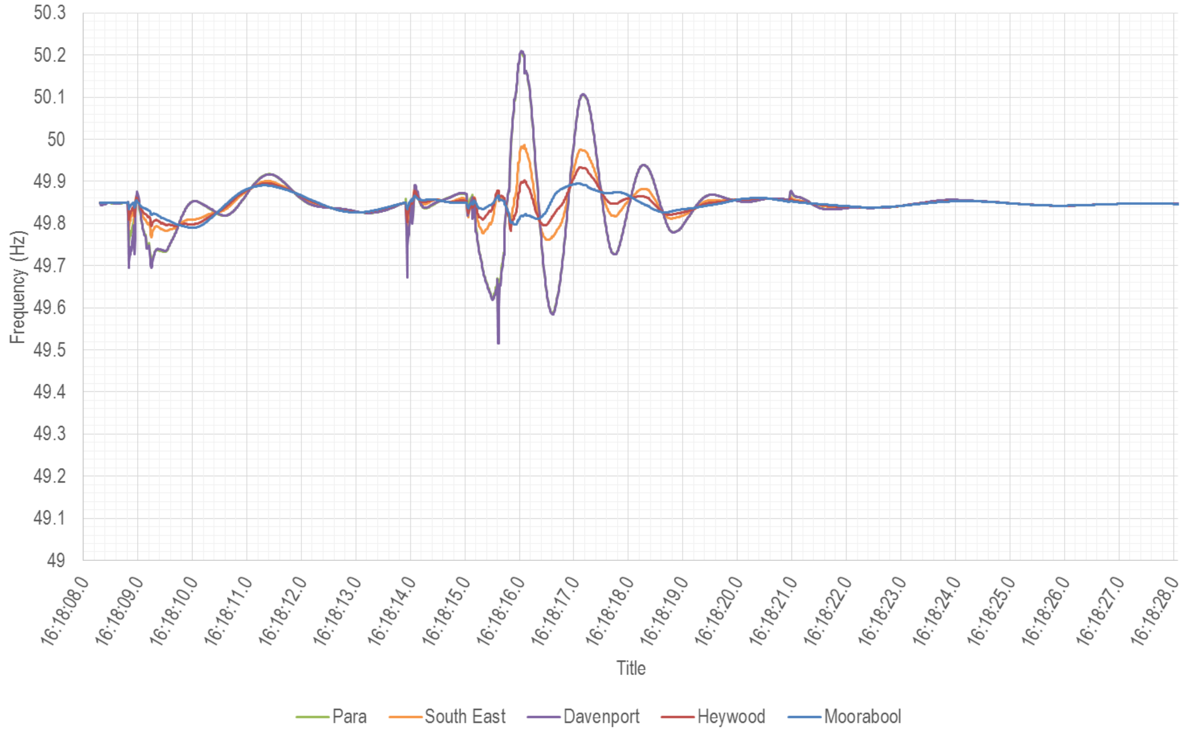


Figure 199 Frequencies at key SA 275 kV substations



Y.4.3 Feasibility of an SPS to prevent system separation for the future events

The operating conditions investigated in this Appendix are the same as those presented in Appendix X.1.2 for the 680 MW Heywood Interconnector import level.

This scenario was shown to cause loss of synchronism and islanding conditions.

Figure 200 to Figure 204 highlight that fast disconnection of 600 MW of load allows the integrity of Heywood Interconnector to be preserved, and results in stable responses across the SA power system. The following generating systems are disconnected due to over voltage protection:

- Cathedral Rocks Wind Farm.
- The Bluff Wind Farm.

Prior to this, Snowtown 2 Wind Farm is disconnected due to a fault at its connection point, and Mt Millar Wind Farm undergoes zero power mode of operation. Heywood Interconnector flow would therefore decrease by 160 MW following completion of 600 MW load shedding.

PSS/E simulation studies

Figure 200 Active and reactive power transfer at Heywood Interconnector

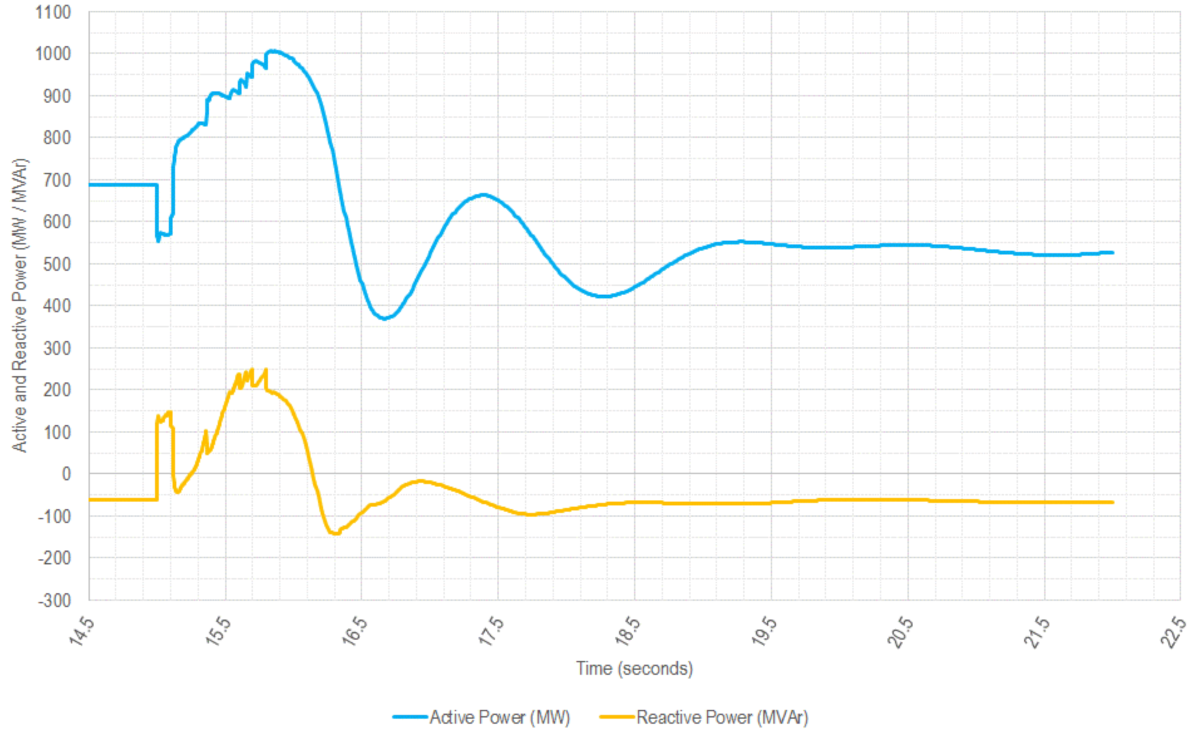


Figure 201 Simulated impedance trajectory at Heywood Interconnector with SPS against relay characteristic area

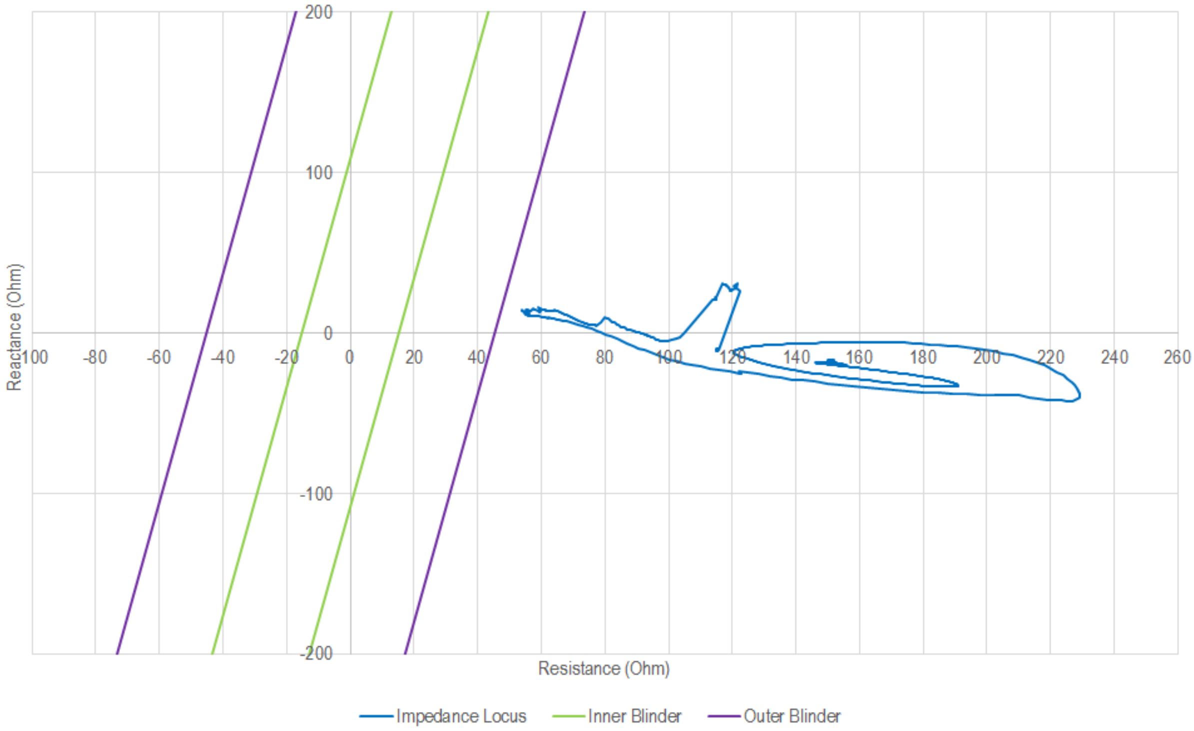


Figure 202 Voltage magnitudes at key SA 275 kV substations

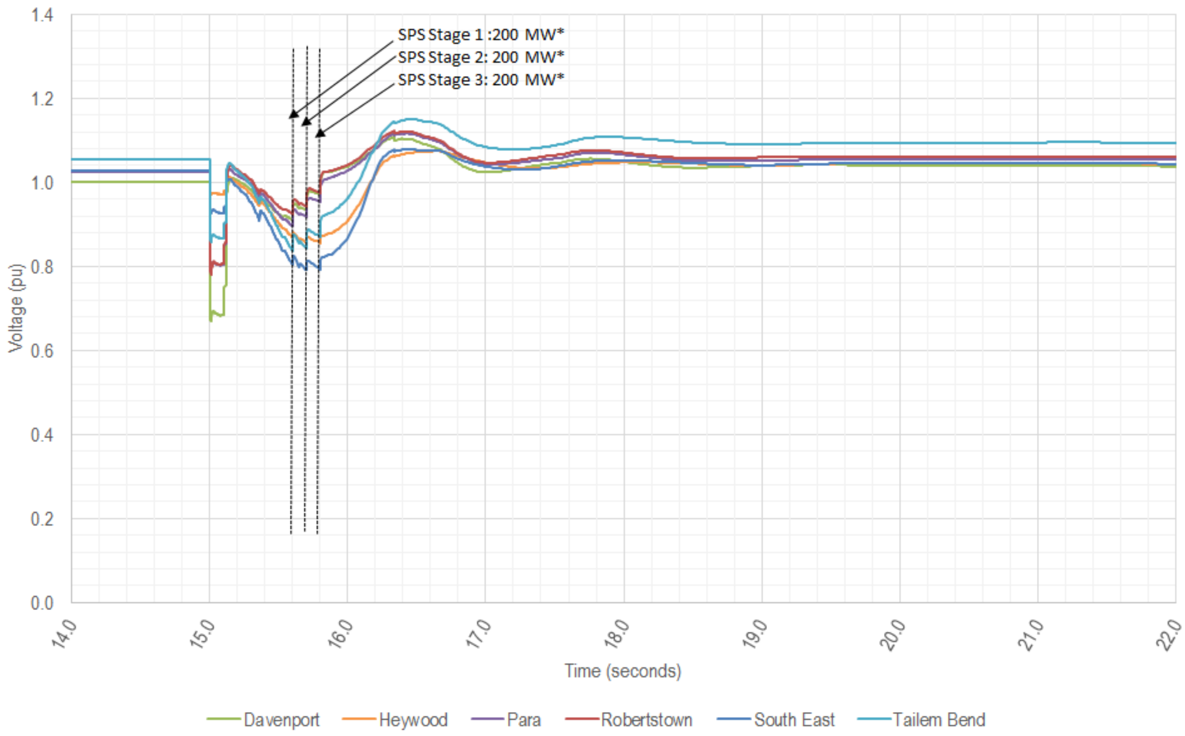


Figure 203 Voltage phase angles relative to HYTS at key SA 275 kV substations

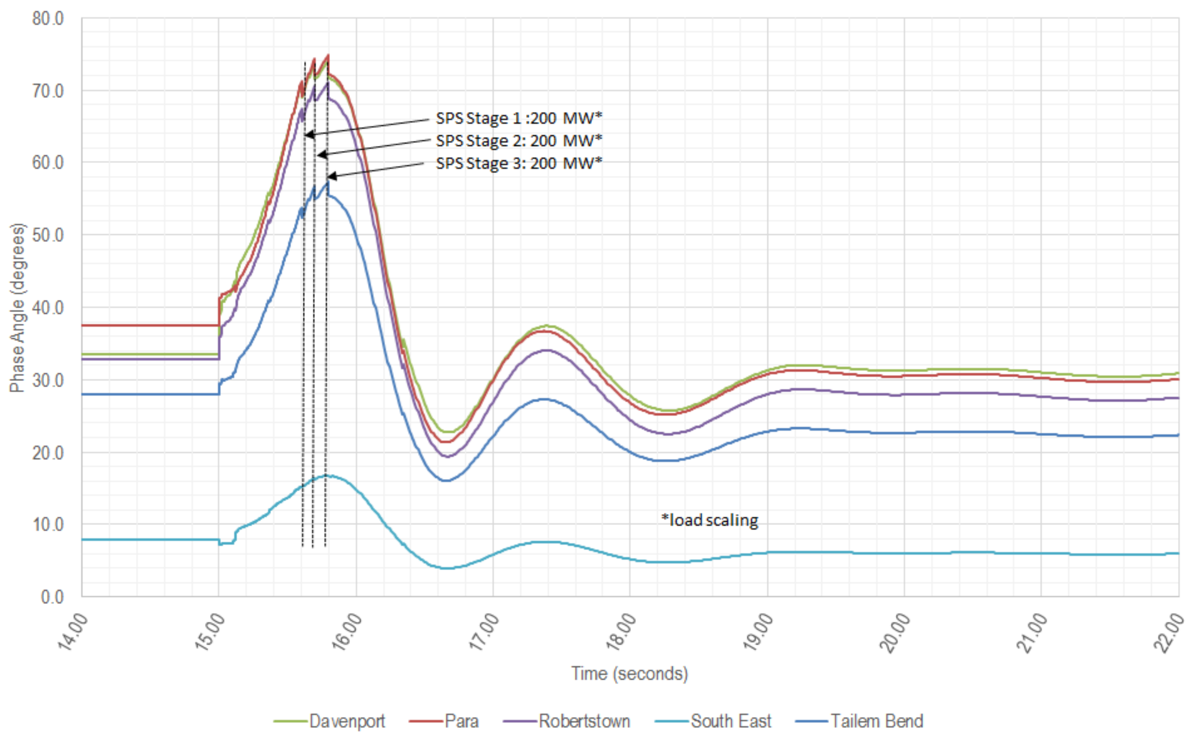
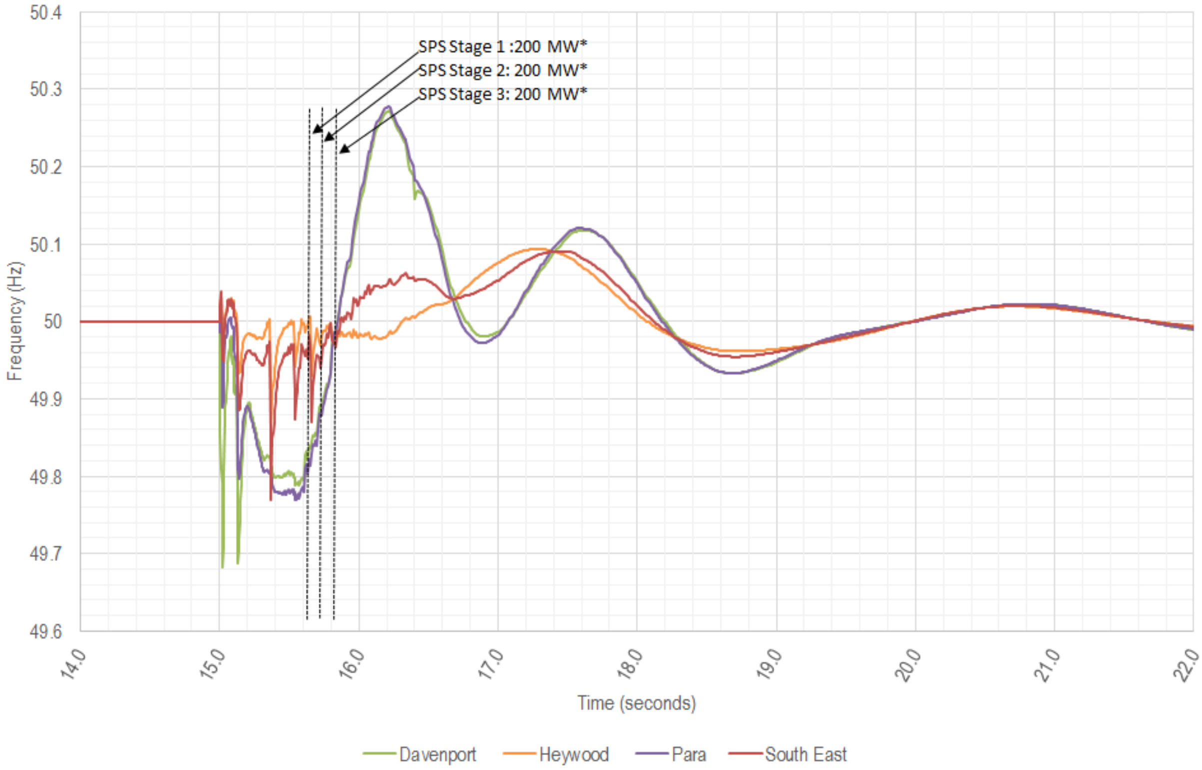


Figure 204 Frequencies at key SA 275 kV substations



Y.5 Feasibility of an SPS to ensure formation of a successful island

This Appendix investigates the effectiveness of an SPS-enabled fast load shedding that starts actioning after system separation, addressing:

- The feasibility of an SPS helping to form a successful island on 28 September 2016.
- The feasibility of an SPS helping to form a successful island in future events.

The SPS aims at compensating for the lost MW infeed as fast as possible, rather than waiting for the falling frequency to trigger smaller load blocks as pertains to the conventional UFLS scheme.

PSS/E simulation studies were attempted first. However, meaningful and stable responses could not be obtained, due to the instability of the simulation tool when analysing extreme operating conditions with the voltages and frequencies declining rapidly in the islanded SA power system. For this reason, simulation studies presented in this Appendix are obtained from the PSCAD simulation tool.

Note that a larger amount of load needs to be shed compared to the pre-emptive load shedding, to compensate for the lost Heywood Interconnector infeed. For this reason, three load blocks of 300 MW are disconnected, each delayed by 100 ms with respect to one another.

PSCAD simulation results presented in Figure 205 to Figure 210 show that a viable island cannot be formed following islanding conditions, even with three TIPS B and Pelican Point CCGT units on-line.

The key determining factor in stability of the islanded SA system is temporary over voltages beyond the over voltage protection settings of the several generating systems.

No attempt was made to shed more than 900 MW of load, as this would have further exacerbated the over voltages experienced. Conversely, a less aggressive load shedding resulting in disconnection of smaller amount of loads would not have allowed the fall in frequency to be arrested above 47 Hz.

Fast disconnection of shunt capacitor banks immediately after islanding conditions could have assisted in mitigating the temporary over voltages. However, most of the seven 275 kV connected 100 MVAr shunt capacitors banks are off-line in the two operating conditions investigated in this report, with only the following capacitors on-line and able to be switched out to mitigate the temporary over voltages:

- 100 MVAr capacitor banks at Para and Tailem Bend for the Black System.
- 100 MVAr capacitor bank at Tailem Bend for the operating conditions discussed in Table 26.

Y.5.1 Feasibility of an SPS to ensure formation of a successful island for the Black System

PSCAD simulation studies

Figure 205 Active and reactive power transfer at Heywood Interconnector

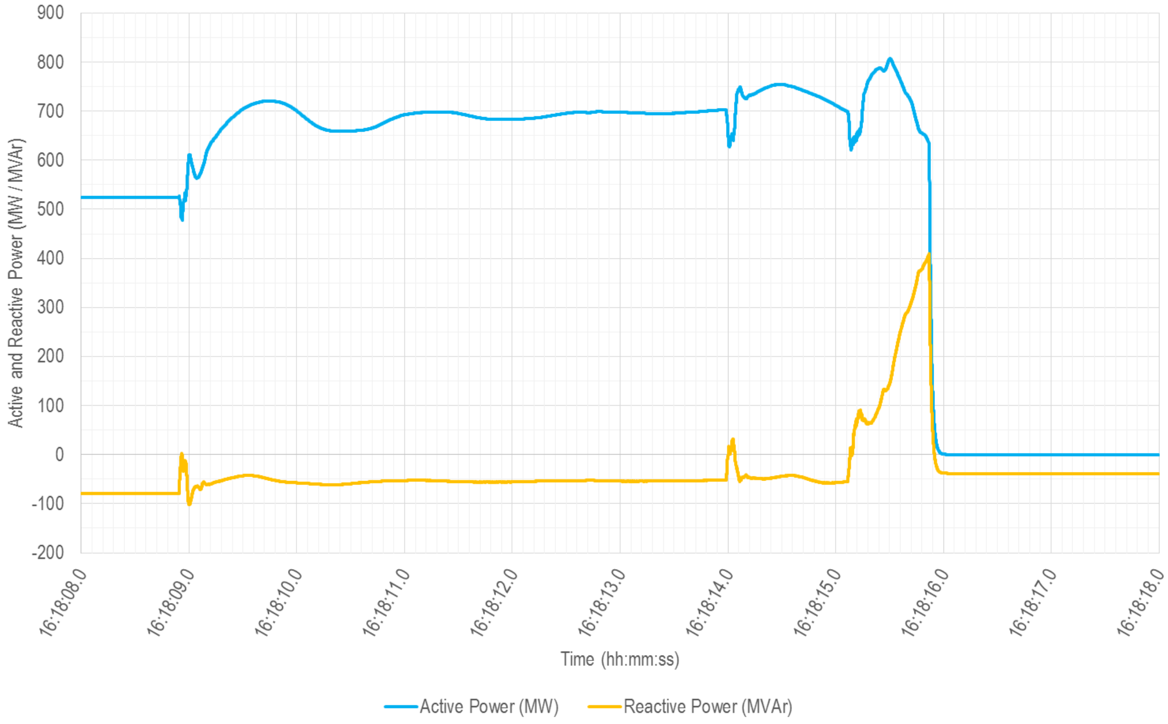


Figure 206 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

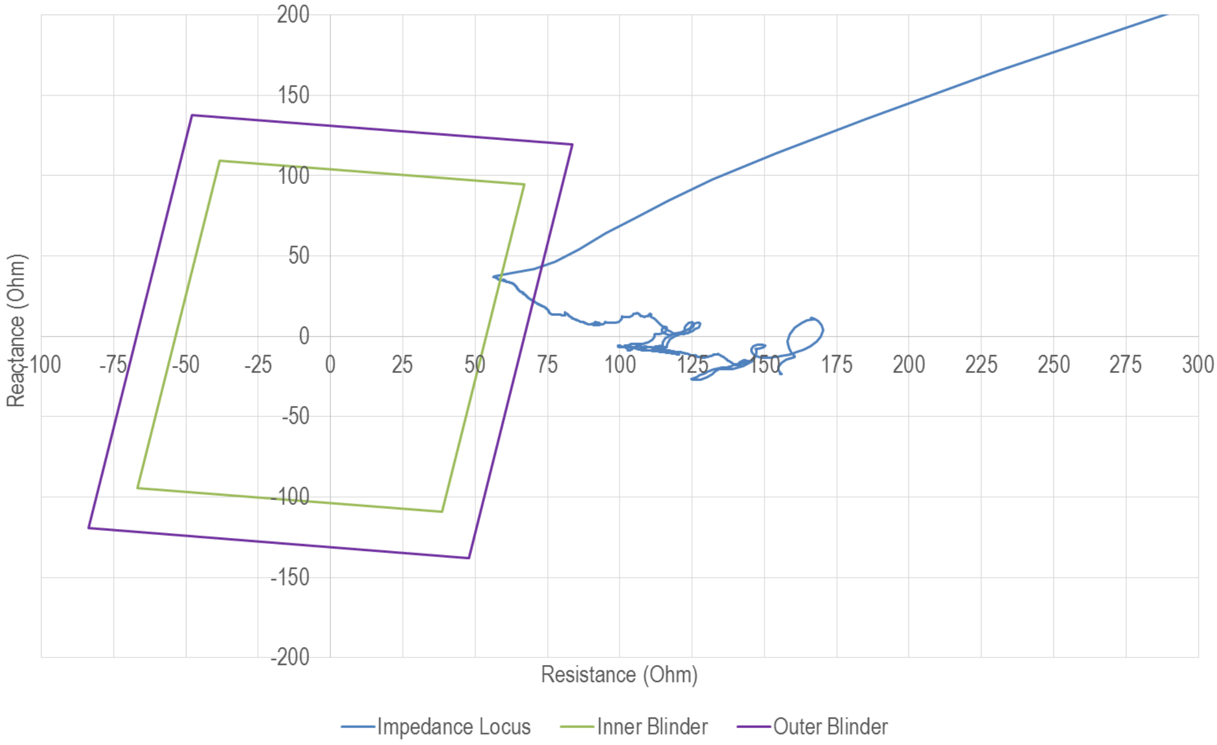


Figure 207 Voltage magnitudes at key SA 275 kV substations

Figure 208 Voltage phase angles relative to HYTS at key SA 275 kV substations

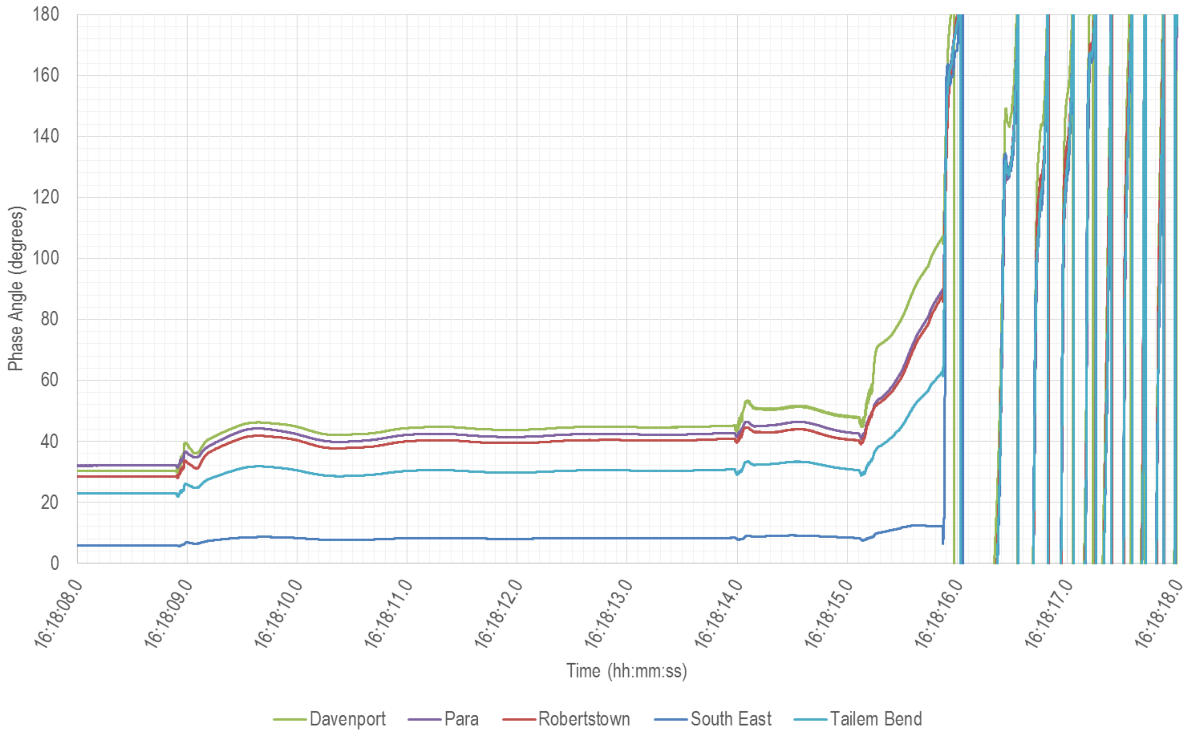


Figure 209 Frequencies at key SA 275 kV substations

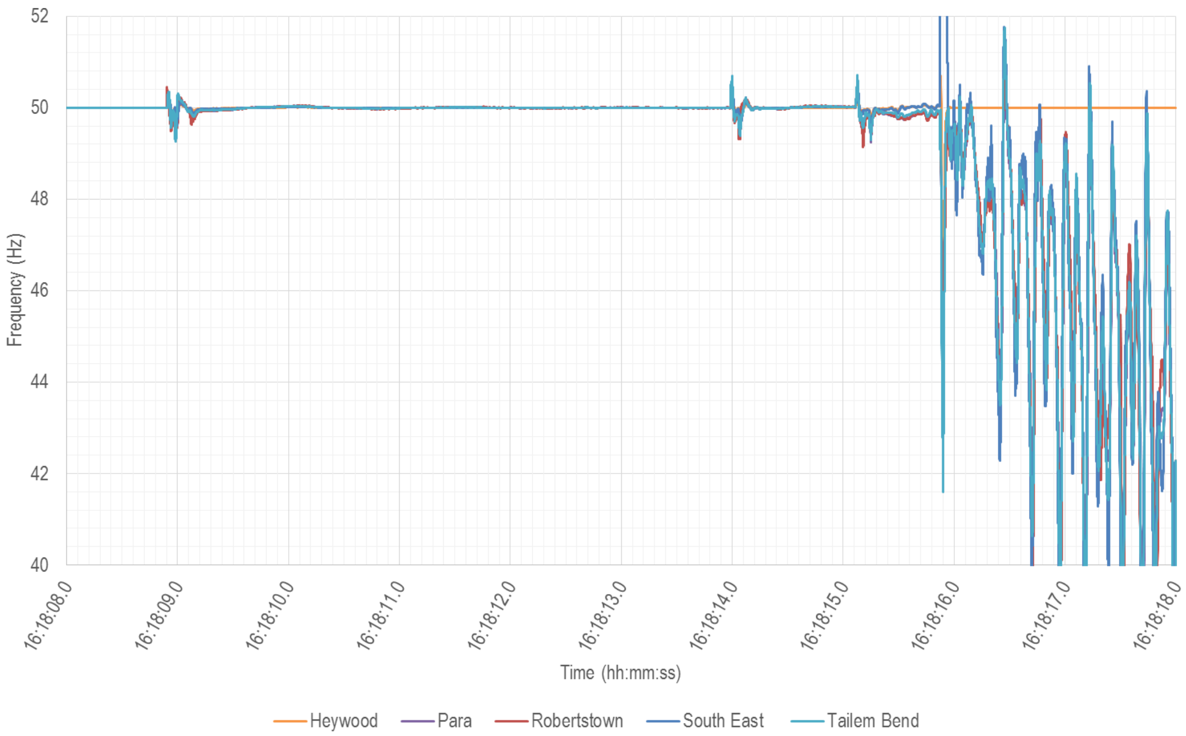


Figure 210 Load shedding profiles

Y.5.2 Feasibility of an SPS to ensure formation of a successful island for future events

PSCAD simulation studies

Figure 211 Active and reactive power transfer at Heywood Interconnector

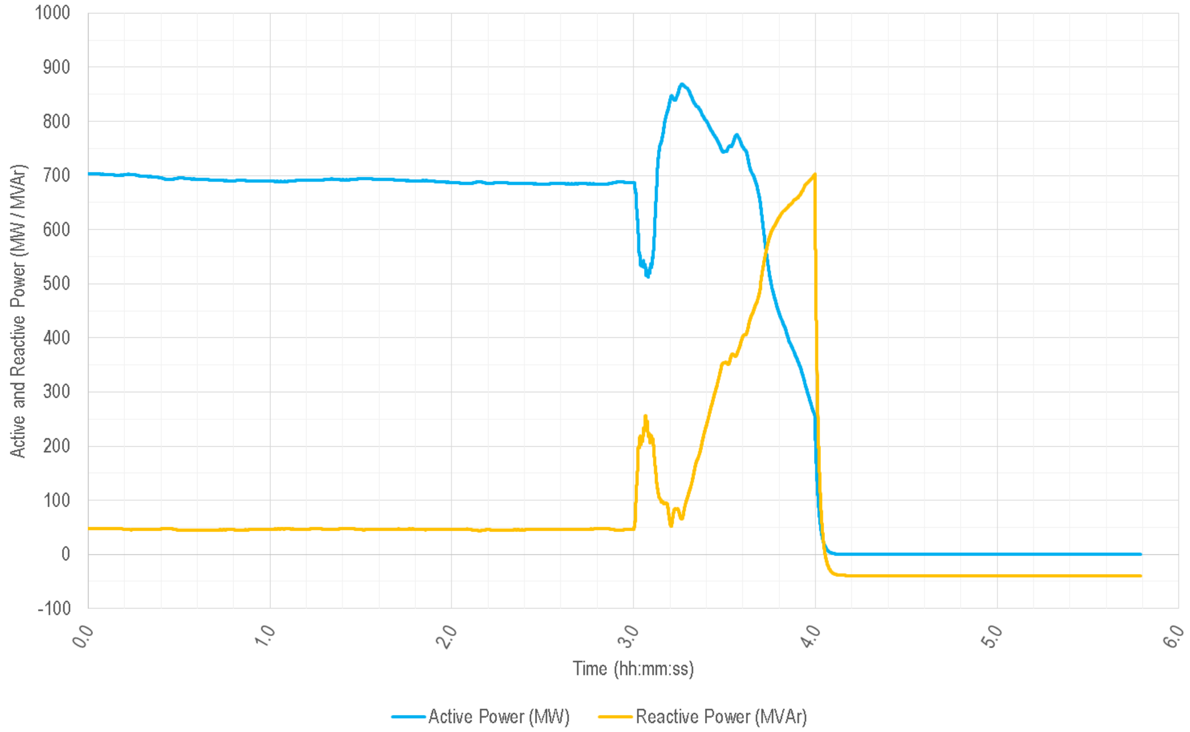


Figure 212 Simulated impedance trajectory at Heywood Interconnector against relay characteristic area

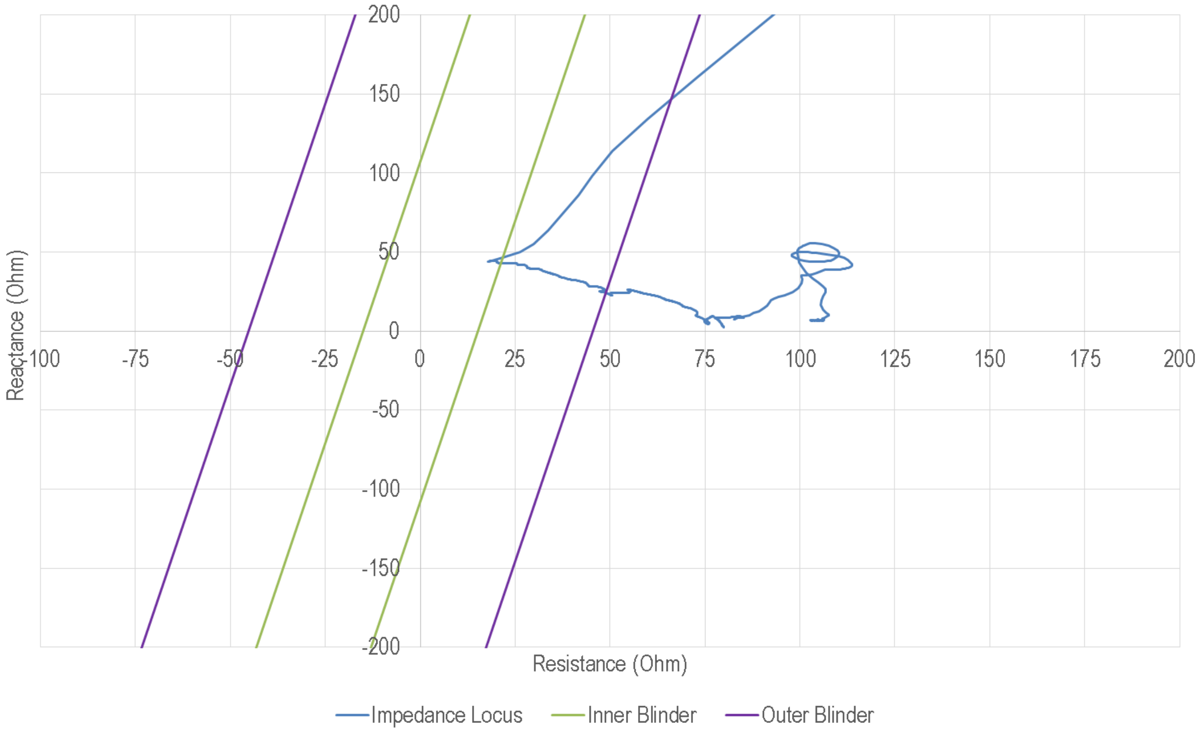


Figure 213 Voltage magnitudes at key SA 275 kV substations

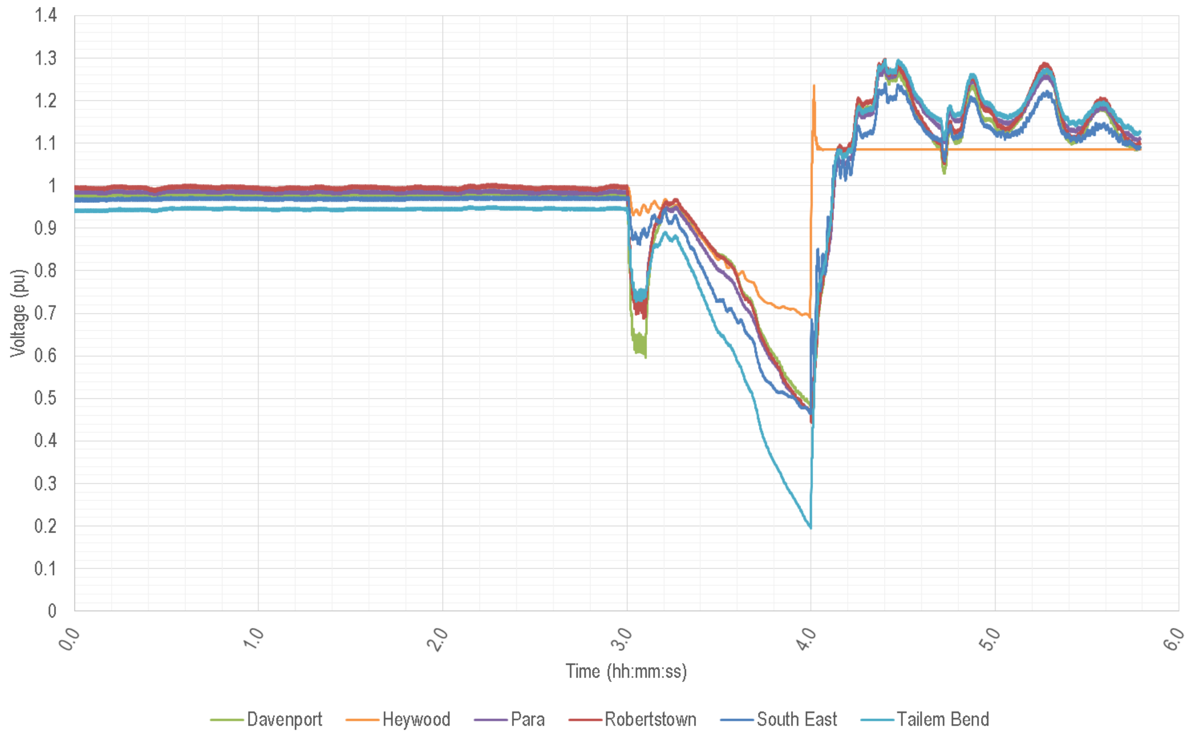


Figure 214 Voltage phase angles relative to HYTS at key SA 275 kV substations

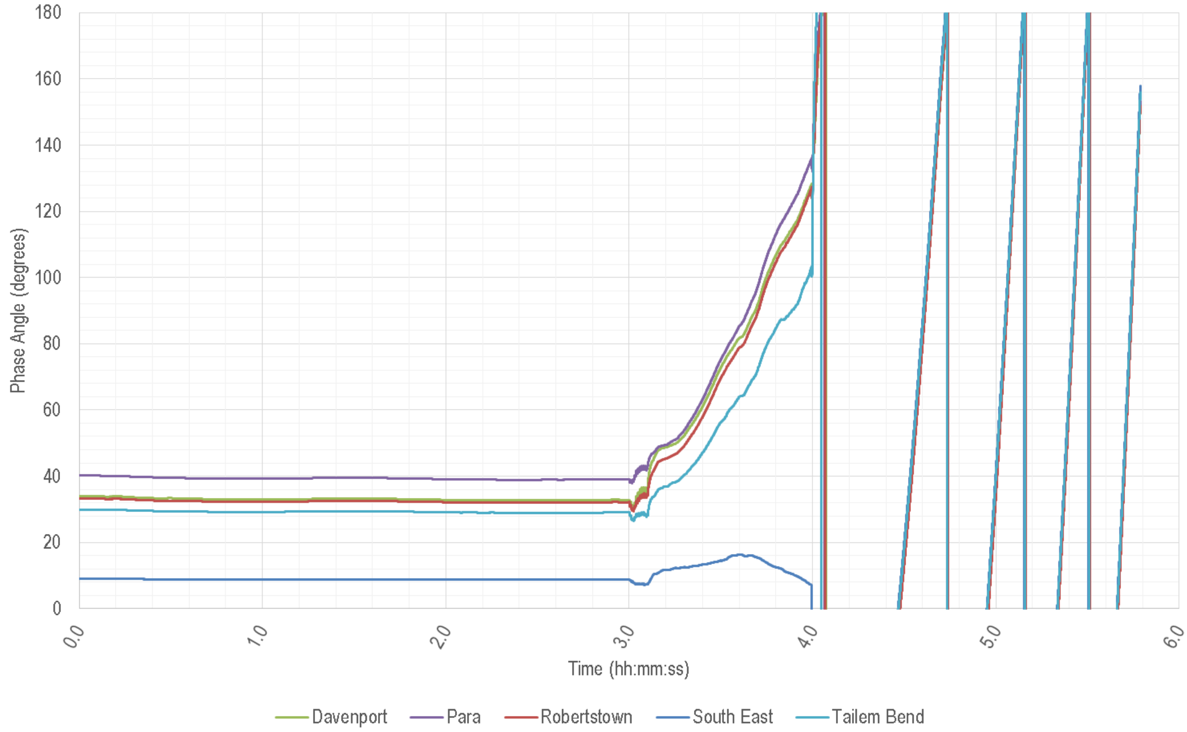
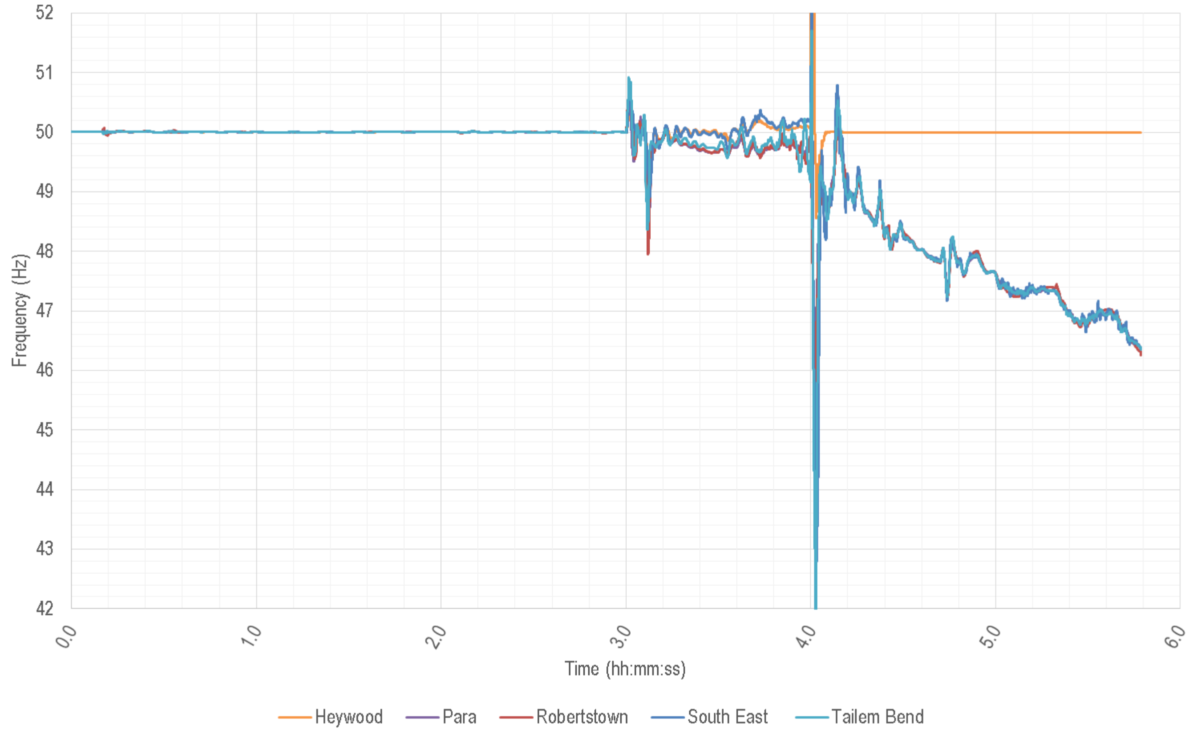


Figure 215 Frequencies at key SA 275 kV substations



Y.6 Adequacy of conventional load shedding schemes

Simulation case studies presented in Appendix Y.5.1 and Y.5.2 indicate that SPS-enabled load shedding with faster speed of response, and a larger amount of load shed, is unable to form a stable island even with dispatch scenarios corresponding to the 3 Hz/s RoCoF constraint.

A more aggressive UFLS scheme would not increase the likelihood of forming a viable island, as it would increase the risk of generator disconnection due to increased temporary over voltages.

Additionally, the system frequency will not drop sufficiently prior to the system separation. A pre-emptive load shedding based on a conventional UFLS scheme is not, therefore, expected to provide significant contribution in preventing islanding conditions in response to events resulting in major loss of generation in the SA.

For these reasons, no simulation studies are presented for the conventional UFLS scheme.

Y.7 Possibility of improvements to response of impedance based relays

Y.7.1 Failure mechanism

Lack of power swing blocking feature

Of ten protection relays that operated at one end of the 275 kV and 132 kV lines (discussed in Section 3.3.3), only the Tailem Bend–Keith 132 kV and Templers–Waterloo 132 kV disconnections are considered to be related to the initial power swing associated with the network conditions on 28 September 2016, which resulted in the loss of synchronism protection tripping at SESS.

Initiation of all other eight distance relays that operated during the Black System commenced after the system separation whose operation mechanism is discussed in this sub-section.

The loss of synchronism phenomenon is generally accompanied by low voltages and high currents in the system. The transmission system distance protection relays could therefore recognise it as three-phase faults.

Without activating the power swing blocking (PSB) functions that are generally included within the distance function in all digital relays, distance protection relays are likely to trip, especially those close to the electrical centre (the electrical centre of the SA power system is near Tailem Bend Substation).

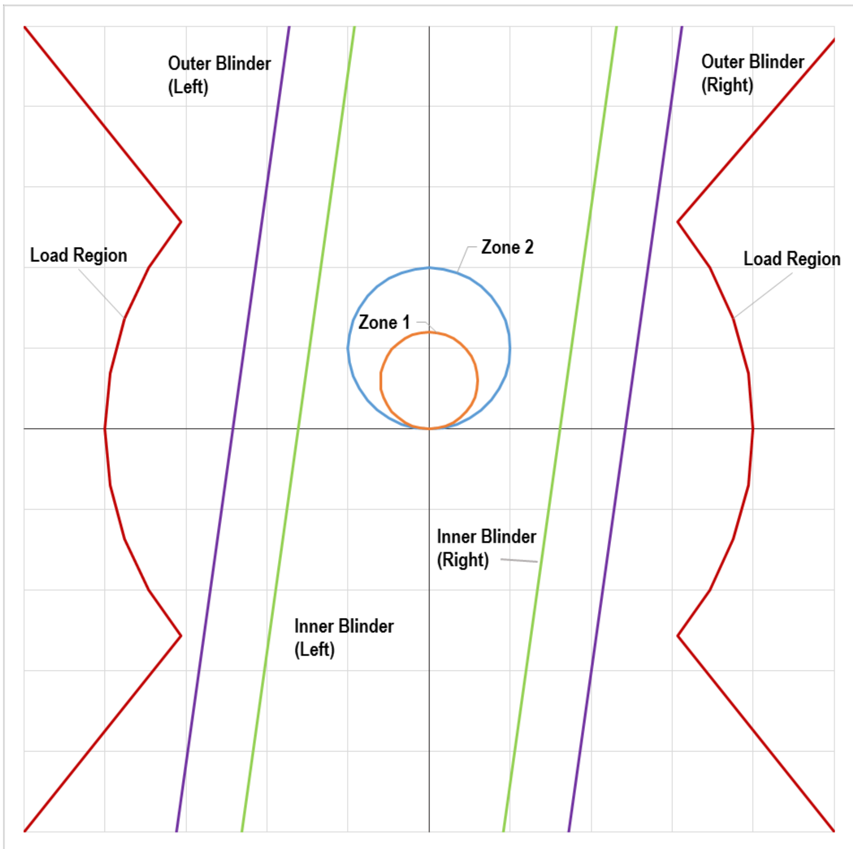
Zone 1 distance relay elements with no intentional time delay are the distance elements most prone to operate during a power swing. This could result in cascaded tripping of several transmission lines, leading to widespread system collapse (as, for example, occurred in the 2003 New York state blackout).

Proper application and setting of the PSB elements would have prevented operation of Zone 1 distance relays for power swings.

Figure 216 shows how the power swing blocking and load encroachment functions can be coordinated with the reach of Zone 1 and 2 for distance relays. Such a coordination would avoid operation of distance relay due to non-faulted power swing events in Zone 1 and 2.

Note that the load encroachment function generally deals with slow developing power swings, and primarily aims at preventing mal-operation of Zone 3 distance relay.

Figure 216 Coordination between conventional distance realy reach, and power swing blocking and load encroachment functions



The Tailem Bend–Keith 132 kV and Templers–Waterloo 132 kV distance relays do not currently have PSB function enabled. This is, however, being considered as part of a Power Swing Blocking project initiated by Electranet which investigates the PSB requirements across the Electranet network.

Operation of these two distances relays in the 132 kV SA transmission system had no impact on the causation chain for the Black System.

Figure 217 and Figure 218 present overlays of measured and PSCAD simulated impedance trajectories against the distance relay characteristic area for each of the two 132 kV lines under consideration.

These figures indicate that the impedance trajectory did not traverse the forward looking Zone 1 or 2 distance elements for either of the relays.

The reason for unexpected operation stems from the way these elements are polarized. The distance elements are polarized using positive-sequence memory voltage. Practical mal-operation of distance relays have been reported in the technical literature for exactly the same reason, when the frequency of the memory voltage polarizing signal and that of the operating signal do not correspond.[146]

The use of the power swing blocking feature would reduce the risk of mal-operation. However, practical experiences exists where mal-operation occurred for relays already enabled with power swing blocking feature. Extensive power system simulation studies are required to confirm that the PSB function operates where it should, and does not operate where it should not.

146 N. Fischer, G. Benmouyal, D. Hou, D. Tziouvaras, J. Byrne-Finley, B. Smyth, "Tutorial on Power Swing Blocking and Out-of-step Tripping", presented at 39th Annual Western Protective Relay Conference, October 2012, available at https://cdn.selinc.com/assets/Literature/Publications/Technical%20Papers/6577_TutorialPower_JBF_20120911_Web.pdf?v=20151125-094320; D. Tziouvaras, "Relay Performance During Major System Disturbances," presented at 60th Annual Conference for Protective Relay Engineers, 2007, pp. 251-270, available at http://ieeexplore.ieee.org/document/4201100/.

To avoid the risk of spurious tripping, the power swing detection algorithms implemented in some protection relays account for small delays for tripping of fast zones, to take an extra cycle of measurements to be able to distinguish between power swings and genuine faults.

Figure 217 Overlay of impedance trajectory and relay characteristic area for Tailem Bend-Keith 132 kV line during the Black System

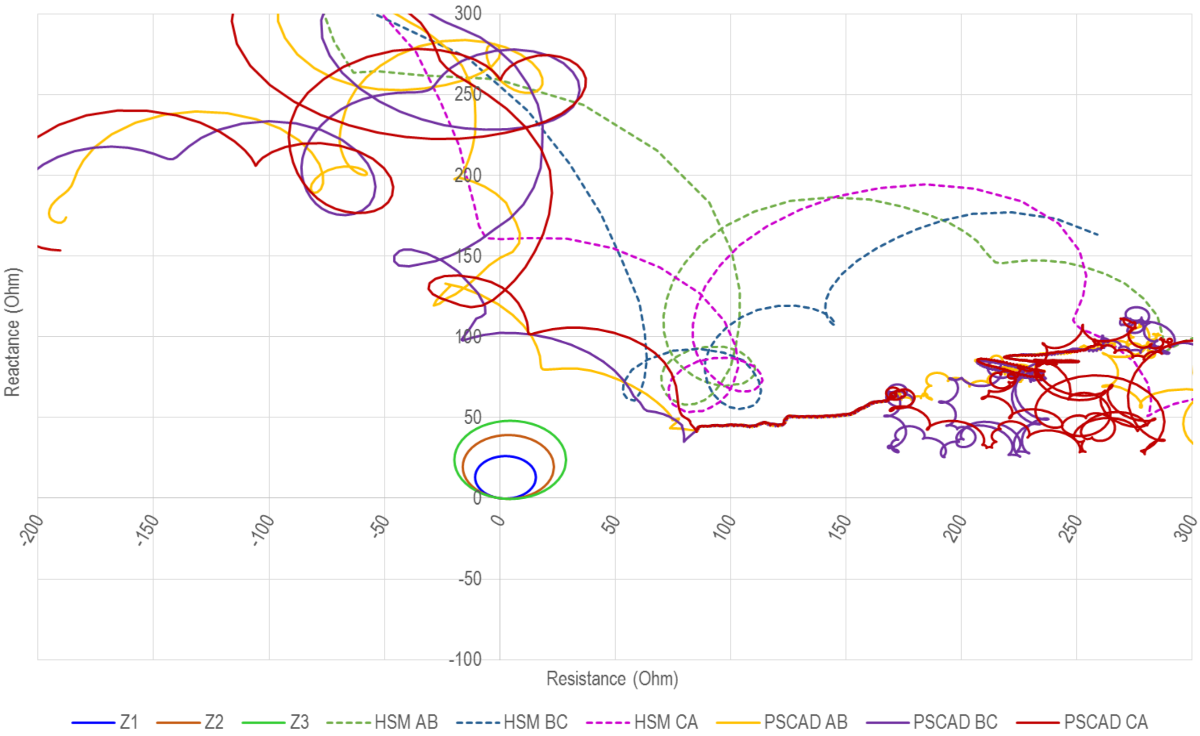
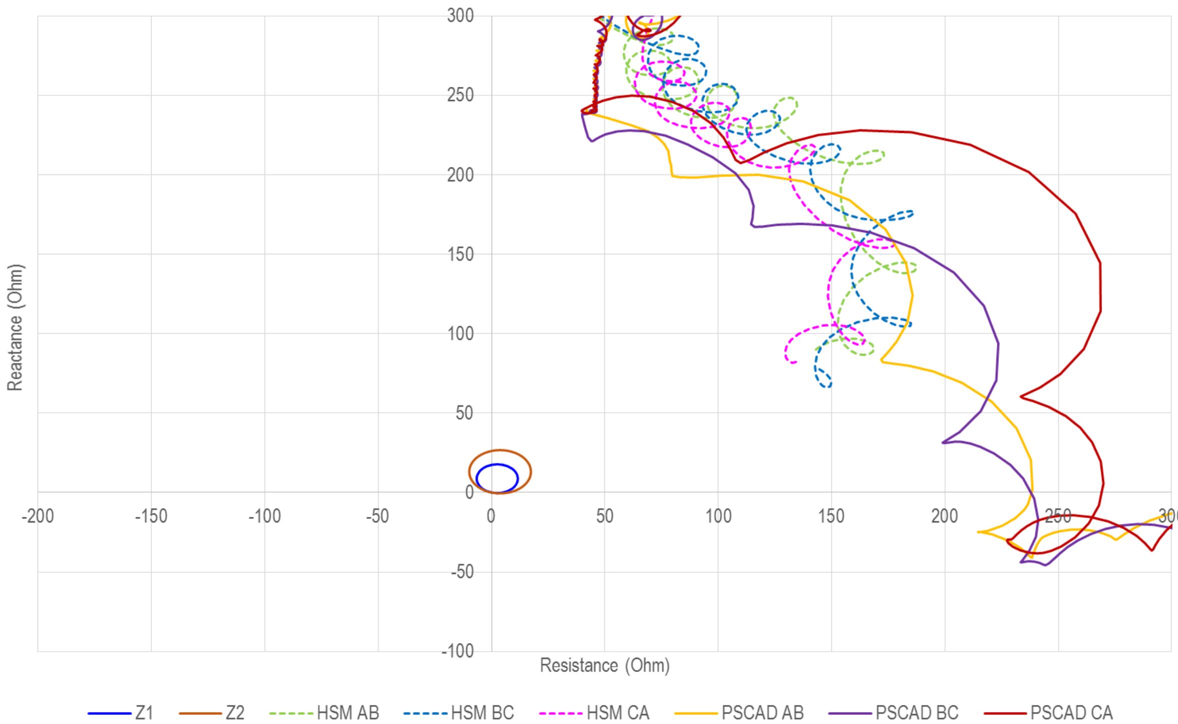


Figure 218 Overlay of impedance trajectory and relay characteristic area for Waterloo-Templers 132 kV line during the Black System



Extreme under frequency and under voltage conditions

Operation of the other eight relays after system separation on 28 September 2016 can be attributed to rapidly declining system voltages and frequencies, both of which simultaneously deviated from their normal steady-state values immediately after the separation with the duration of excursion for some of the relays persisted significantly longer than that occurring during fault conditions.

All distance relays use a polarizing or memory quantity, which is the reference quantity to determine whether or not the distance relay should operate. Voltage is generally used as the polarizing quantity. However, comparator-based mho[147] distance elements require a polarizing quantity to provide a reliable angle reference, and are therefore also susceptible to large and sustained changes in the frequency.

ElectraNet is currently working with the respective relay vendors to prevent operation of those eight relays for any potential future system separation events which may result in similarly large and sustained changes in the voltages and/or frequencies.

Y.7.2 Other points to consider

- Power swings are complex events, and dynamic interaction between the primary power system equipment and protective functions must be accurately accounted for. For this reason correct distinction between stable and unstable swings can only be practically achieved by detailed power system modelling and simulation studies. Close collaboration between engineers who perform power system modelling and simulation, and the protection engineers who implement those settings, is essential to ensure secure and reliable settings for these relays.
- Unlike the USA where the North-American Electric Reliability Corporation (NERC) sets out specific requirements on the acceptable performance of the distance relays and power swing blocking / out-of-step tripping functions, Australia does not have overarching rules on the required response of generator and network protection to power swings. AEMO's initial assessment indicates that the power swing blocking function is not widely used in the SA, Victoria, and New South Wales transmission networks. It is recommended that AEMO, in consultation with TNSPs and Generators[148], develop requirements for expected performance of power swing blocking for transmission networks and out-of-step tripping for synchronous generators.
- Additionally, a standardised strategy on location and distinction between power swing blocking and out-of-step tripping functions is necessary. Survey of international practices indicates that the out-of-step tripping is applied at predefined locations for system separation in case of unstable power swings, similar to that applied to the Heywood Interconnector, whereas the power swing blocking function is implemented elsewhere in the transmission system. Note that:
  – The power swing blocking feature is generally implemented as a supervisory function for operation of the distance relay. The blocking feature is primarily intended to apply to Zone 1 and in some circumstances for Zone 2 of distance relays.
  – The out-of-step tripping feature is generally implemented as a standalone relay rather than as a supervisory element for the distance relays.
- While evaluation of relay settings through power system simulation studies will contribute to developing secure and reliable settings for power swing blocking functions, relays offered by different vendors have subtle differences and features, not included in the respective simulation models. Such subtle features can have significant implications in the response of power swing blocking function. Additional understanding and confidence in relay algorithm and performance can be gained by lab testing or commissioning testing of the relay using simulated waveforms. In this case, simulated responses can be injected into the actual relay using a playback method, the necessary intermediate hardware such as RelaySimTest. The simulated waveforms can be generated from offline studies based on electromagnetic transient (EMT)-type simulation such as PSCAD/EMTDC, or from on-line studies using real-time digital simulation (RTDS).

[147] The reciprocal of Ohm.
[148] The power swing blocking feature only applies to synchronous generators.