SYSTEM STRENGTH REQUIREMENTS METHODOLOGY

SYSTEM STRENGTH REQUIREMENTS & FAULT LEVEL SHORTFALLS

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1.0	1 July 2018	First issue

EXECUTIVE SUMMARY

System strength is an inherent *power system* characteristic – it is a measure of its stability under all reasonably possible operating conditions.

At present, system strength is provided by *synchronous generation*. The commencement of the National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10 (**Fault Level Rule**) establishes a new framework for the management of system strength.

AEMO is now required to determine the minimum *three phase fault levels* at each *fault level node* in each *region* in accordance with the *system strength requirements methodology*. The minimum *three phase fault levels* at each *fault level node* are referred to collectively as the *system strength requirements*.

Upon determining the *system strength requirements* for each *fault level node,* AEMO is required to determine whether there are any *fault level shortfalls*.

2018 Fault level nodes

The *fault level nodes* for each *region* are listed in Table 1.

2018 Minimum three phase fault levels

The minimum *three phase fault levels* for 2018 at each *fault level node* are also listed in Table 1.

Table 1 Fault level nodes and minimum three phase fault levels for 2018

Region	Fault Level Nodes	Minimum Three Phase Fault Level (MVA)
South Australia	Davenport 275 kV	1150
	Robertstown 275 kV	1400
	Para 275 kV	2200
Tasmania	George Town 220 kV	1450
	Waddamana 220 kV	1400
	Burnie 110 kV	750
	Risdon 110 kV	1330
Queensland	Western Downs 275 kV	2550
	Greenbank 275 kV	3800
	Nebo 275 kV	1750
	Gin Gin 275 kV	2400
	Lilyvale 132 kV	1100
New South Wales	Armidale 330 kV	3000
	Sydney West 330 kV	9250
	Wellington 330 kV	1900
	Newcastle 330 kV	8400
	Darlington Point 330 kV	1550
Victoria	Hazelwood 500 kV	8850
	Dederang 220 kV	3500
	Thomastown 220 kV	4100
	Red Cliffs 220 kV	600
	Moorabool 220 kV	4400

Fault level shortfalls

Currently, the only *region* with a *fault level shortfall* is South Australia.

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1 INTRODUCTION

1.1 Purpose and scope

AEMO *publishes* in this document the:

(a) initial *system strength requirements methodology* determined under clause 11.101.3(a) of the National Electricity Rules (**NER**) (**Methodology**);

(b) initial *system strength requirements* determined under clause 11.101.4(a) of the NER; and

(c) initial *fault level shortfalls* determined under clause 11.101.4(b) of the NER.

The Methodology, *system strength requirements* and *fault level shortfalls* have effect only for the purposes set out in the NER. The NER and the *National Electricity Law* prevail over this document to the extent of any inconsistency.

1.2 Definitions and interpretation

1.2.1 Glossary

The words, phrases and abbreviations in the table below have the meanings set out opposite them when used in this document.

Terms defined in the *National Electricity Law* and the NER have the same meanings in this document unless otherwise specified.

Terms defined in the NER are intended to be identified in this document by italicising them, but failure to italicise a defined term does not affect its meaning.

Term	Definition
EMT	Electromagnetic transient.
EMTDC	Electromagnetic transients including DC.
FACTS	Flexible AC *transmission systems.*
Fault Levels Rule	National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10.
LNSP	*Local Network Service Provider.*
NER	National Electricity Rules.
NSP	*Network Service Provider.*
NTNDP	National Transmission Network Development Plan.
OPDMS	Operations and Planning Data Management System.
PSCAD™/EMTDC™	Power System Computer Aided Simulation / Electromagnetic Transient with Direct Current.
PV	Photovoltaic
PSS®E	Power System Simulator for Engineering.
RMS	Root mean square.
SA	South Australia.
SASSA	AEMO's report entitled: South Australia System Strength Assessment. Available at: http://aemo.com.au/-/media/Files/Media_Centre/2017/South_Australia_System_Strength_Assessment.pdf
SCR	Short circuit ratio
SSSP	*System Strength Service Provider.*
Stage 1	The studies referred to in section 9.1.
Stage 2	The studies referred to in section 9.2.
Synchronous Machines	*Synchronous generating units* and *synchronous condensors.*
TAS	Tasmania.

Term	Definition
Type I	When used in the context of WTGs, induction generators.
Type II	When used in the context of WTGs, induction generators with variable rotor resistor.
Type III	When used in the context of WTGs, doubly-fed *asynchronous generating units*.
Type IV	When used in the context of WTGs, rotating machine (synchronous or induction) *connecting* to the *network* via full scale back-to-back converters.
WTG	Wind turbine generator.

1.2.2 Interpretation

The following principles of interpretation apply to this document unless otherwise expressly indicated:

(a) This document is subject to the principles of interpretation set out in Schedule 2 of the *National Electricity Law*.

(b) the words "**includes**", "**including**" or "**such as**" are not words of limitation, and when introducing an example, do not limit the meaning of the words to which the example relates to examples of a similar kind.

2 CONTEXT

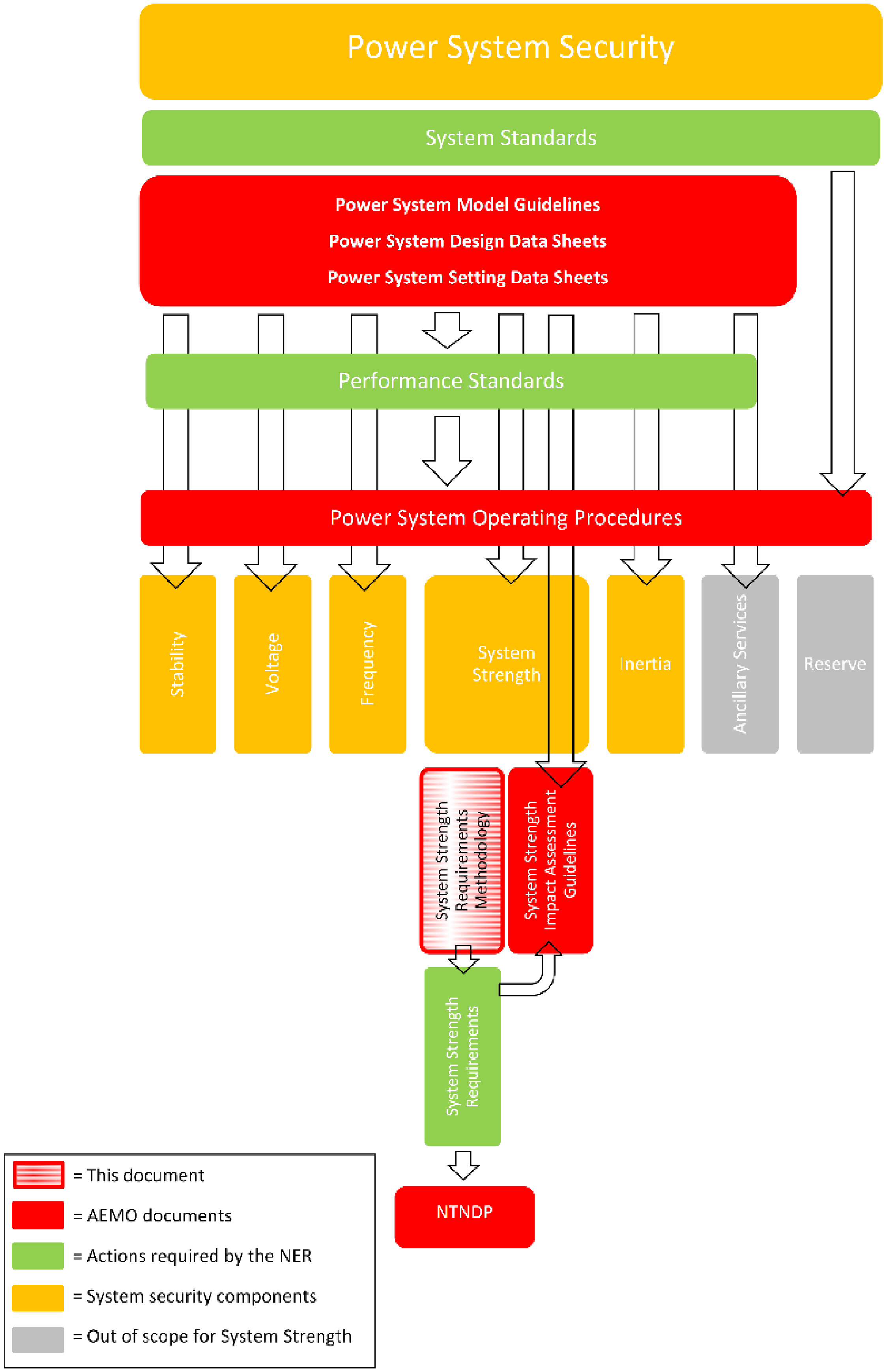
This document specifies:

(a) the process AEMO has used to determine the *system strength requirements* for each *fault level nodes* for 2018 and the process it intends to use for 2019 and beyond; and

(b) the *system strength requirements* for 2018 and *fault level shortfalls* for 2018.

Figure 1 shows the interrelationship between this document and other NER instruments and AEMO guidelines, operating procedures and activities. By no means a complete depiction, it highlights how the Methodology fits in with a number of existing and new requirements on AEMO's ability to meet its *power system security responsibilities*.

Figure 1 Interrelationship of system strength framework components with other power system security requirements



2.1 Relationship with other processes and documents

2.1.1 Inertia requirements methodology and inertia requirements

The National Electricity Amendment (Managing the rate of change of power system frequency) Rule (2017 No.9[1] requires AEMO to complete the following by 30 June 2018:

- Develop and *publish* an *inertia requirements methodology*[2].
- Using the *inertia requirements methodology*, determine the *inertia requirements* for each *inertia sub-network*[3] and assess whether an *inertia shortfall* is likely to arise at any time within a planning horizon of at least five years[4].

System strength and *inertia* are related because they can both be enhanced by *dispatching* Synchronous Machines. Therefore, there may be a correlation between the *system strength requirements* and *inertia requirements*, as well as any *fault level shortfalls* and *inertia shortfalls*. It should be noted, however, that there are mechanisms to address *inertia shortfalls* that have no impact on system strength, such as fast under-*frequency load shedding* or the fast *frequency* response.

2.1.2 System Strength Impact Assessment Guidelines

NSPs are required by the Fault Levels Rule to conduct *system strength impact assessments* for new or modified *generation connections* and new *market network service facilities*[5].

The Fault Levels Rule also requires AEMO to *publish* the *system strength impact assessment guidelines*, setting out the methodology to be used by NSPs in conducting their *system strength impact assessments*[6].

AEMO's determination of *system strength requirements* and *fault level shortfalls* will support the NSPs' *system strength impact assessments*, by indicating the minimum *three-phase fault levels* at *fault level nodes*. This is then translated into the Synchronous Machine *dispatch* pattern which will be used by the NSP undertaking *system strength impact assessment* on a new or modified *connections*.

2.1.3 Power System Model Guidelines

The *Power System Model Guidelines* detail AEMO's requirements for data and models from Applicants and facilitate access to the technical information and modelling data necessary to perform the required analysis.

Submission of accurate models in an appropriate format facilitates a robust analysis of the *power system*, leading to confidence in the assessment of the *system strength requirements*.

3 BACKGROUND

3.1 What is system strength?

System strength can be simplified into the available fault current at a specified location in the *power system*, where higher fault current indicates higher system strength.

System strength at a given location is usually determined by two factors:

- the number of Synchronous Machines *connected* nearby; and
- the number of *transmission lines* or *distribution lines* (or both) *connecting* Synchronous Machines to the rest of the *network*.

It also involves complex interactions between many electrical and mechanical elements within the *power system*. This relates to all *network* components, including Synchronous Machines, *asynchronous generation* (and their *protection systems*), and FACTS devices.

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[1] Available at https://www.aemc.gov.au/rule-changes/managing-the-rate-of-change-of-power-system-freque

[2] Clause 11.100.3(a)

[3] For the purposes of the *inertia requirements methodology* to be *published* by 30 June 2018, these are deemed by clause 11.100.2 to be the *regions* as at 19 September 2017.

[4] Clause 11.100.4(a). The planning horizon arises out of the application of clause S5.20.2(c)(12).

[5] NER clause 5.3.4B.

[6] NER clause 4.6.6.

3.1.1 Why system strength is important in the NEM

Low system strength could lead to:

- higher *voltage* step changes following shunt device switching, such as capacitor banks, which could breach *system standards*;
- increased risk of *generating system* instability following a c*redible contingency event*;
- reduced sensitivity of *power system* protection devices due to reduced fault current, if the protection devices operate on measurement of fault current.

Historically, it was not necessary to consider system strength as a necessary service to achieve *power system security* because there were many *synchronous generating systems connected* to the *power system*, and these inherently provided system strength as a matter of course.

Synchronous generation retirements could have a significant impact on system strength, as *synchronous generators* are currently the largest contributors to system strength.

At present, *asynchronous generation*, including inverter-based *generation*, does not contribute to system strength as much as *synchronous generation*. Most inverter-based *asynchronous generating systems* require a minimum system strength at their *connection point* to maintain stable operation under normal conditions and following a *credible contingency event*. With the increasing penetration of *asynchronous generation* and potential *synchronous generation* retirements in the *NEM*, the minimum system strength required to maintain the secure and stable operation of the *power system* is likely to increase.

With present technology, Synchronous Machines are the largest contributors to the system strength. This system strength contribution can only be achieved if Synchronous Machines are located electrically close to where the system strength support is needed.

4 THE FAULT LEVELS RULE

The National Electricity Amendment (Managing power system fault levels) Rule 2017 No. 10 (**Fault Level Rule**)[7] established a framework for the management of system strength.

There are two aspects to this framework:

(a) Each *region's System Strength Service Provider* (**SSSP**) is required to maintain the minimum *three phase fault levels* at each *fault level node* in each *region*. AEMO is required to determine where the *fault level nodes* are in each *region*, plus the minimum *three phase fault levels* and *fault level shortfalls* at those *fault level nodes*. *Fault level shortfalls* are then to be addressed by the SSSPs providing *system strength services*.

(b) New *connections* for *generation, market network service facilities* and alterations to *generating systems* that give rise to an *adverse system strength impact* are to be addressed by the relevant *Connection Applicant* or *Generator*, either by providing a *system strength remediation scheme*, or by paying the *connecting* NSP to undertake *system strength connection works* to alleviate the *adverse system strength impact*.

This document addresses the first aspect only.

5 HOW AEMO ADDRESSES SYSTEM STRENGTH

5.1 Prior to commencement of the Fault Levels Rule

NSPs are responsible for ensuring the accurate operation of *protection systems*, as well as maintaining power quality within *Australian Standards* and *system standards*.

The *NSCAS* framework provides a mechanism to procure services to maintain *power system security*, which may include services to increase system strength, however, that framework only addresses issues on an ad-hoc basis and imposes no clear obligations on AEMO to consider system strength issues on a regular basis.

[7] See https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels.

Following the *black system* event of 28 September 2016,[8] AEMO assessed system strength in the South Australian (**SA**) *power system* and determined a minimum number of *synchronous generating unit* combinations that must be operating at all times for SA to operate in a secure manner. This assessment was conducted for conditions when SA is *connected* to the rest of *NEM*, following a credible separation event, and during *islanding* conditions. Since then, AEMO has been operating the SA *power system* with the necessary number of *synchronous generating unit* combinations[9] to maintain a *secure operating state*.

5.2 Following commencement of the Fault Levels Rule

The matters related to *system strength requirements* AEMO is required to determine are detailed in Section 6 and Section 7.

6 DEFINING SYSTEM STRENGTH REQUIREMENTS

6.1 What are the system strength requirements?

The *system strength requirements* that AEMO must determine for each *region* are specified in clause 5.20C.1(b) as follows:

(2) the *fault level nodes* in the *region*, being the location on the *transmission network* for which the *three phase fault level* must be maintained at or above a minimum *three phase fault level* determined by *AEMO*; and

(3) for each *fault level node*, the minimum *three phase fault level*.

The *system strength requirements* are to be determined by applying the *system strength requirements methodology*, also to be determined by AEMO[10].

6.2 System strength requirements methodology

Clause 5.20.7(b) details the requirements for the *system strength requirements methodology*:

(b) The *system strength requirements methodology* determined by *AEMO* must provide for *AEMO* to take the following matters into account in determining the *fault level nodes* and the minimum *three phase fault level*:

(1) the combination of *three phase fault levels* at each *fault level node* in the *region* that could reasonably be considered to be sufficient for the *power system* to be in a *secure operating state*;

(2) the maximum *load shedding* or *generation shedding* expected to occur on the occurrence of any *credible contingency event* or *protected event* affecting the *region*;

(3) the stability of the *region* following any *credible contingency event* or *protected event*;

(4) the risk of *cascading outages* as a result of any *load shedding* or *generating system* or *market network service facility* tripping as a result of a *credible contingency event* or *protected event* in the *region;*

(5) additional contribution to the *three phase fault level* needed to account for the possibility of a reduction in the *three phase fault level* at a *fault level node* if the *contingency event* that occurs is the loss or unavailability of a *synchronous generating unit* or any other *facility* or service that is material in determining the *three phase fault level* at the *fault level node*;

(6) the stability of any equipment that is materially contributing to the *three phase fault level* or *inertia* within the *region;* and

(7) any other matters as *AEMO* considers appropriate.

[8] See http://aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf.

[9] The Transfer Limit Advice South Australia System Strength is regularly updated, and is available at: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf.

[10] Clause 5.20C.1.

Further details of how AEMO has considered these matters can be found in Sections 8 and 9.

6.3 Fault level nodes

A *fault level node* is defined as:

> A location on a *transmission network* that *AEMO* determines is a *fault level node* in its determination of *system strength requirements* under clause 5.20C.1(a).

Further details on how AEMO has determined the *fault level nodes* can be found in section 8.

6.4 Minimum three phase fault level

The minimum *three phase fault level* is the *three phase fault level* to be maintained by each *region's* SSSP at each *fault level node* to maintain the *power system* in a *secure operating state*.

Maintenance of the minimum *three phase fault level* at each *fault level node* does not mean that it has to be maintained under all conditions. SSSPs are expected to maintain it to a level that is consistent with AEMO's obligation to achieve the *AEMO power system security responsibilities* in accordance with the *power system security* principles described in clause 4.2.6 in clause 4.2.6 of the NER.

Further details on how AEMO has determined the minimum *three phase fault levels* can be found in Section 9.

7 FAULT LEVEL SHORTFALLS

In the context of *fault level shortfalls*, clause 5.20C.2 requires the following:

(a) *AEMO* must as soon as practicable following its determination of the *system strength requirements* for a *region* under clause 5.20C.1 assess:

  (1) the *three phase fault level* typically provided at each *fault level node* in the *region* having regard to typical patterns of *dispatched generation* in *central dispatch*;

  (2) whether in *AEMO's* reasonable opinion, there is or is likely to be a *fault level shortfall* in the *region* and *AEMO's* forecast of the period over which the *fault level shortfall* will exist; and

  (3) where *AEMO* has previously assessed that there was or was likely to be a *fault level shortfall*, whether in *AEMO's* reasonable opinion that *fault level shortfall* has been or will be remedied.

(b) In making its assessment under paragraph (a) for a *region*, *AEMO* must take into account:

  (1) over what time period and to what extent the *three phase fault levels* at *fault level nodes* that are typically observed in the *region* are likely to be insufficient to maintain the *power system* in a *secure operating state*; and

  (2) any other matters that *AEMO* reasonably considers to be relevant in making its assessment.

Further details on how AEMO has determined the *fault level shortfalls* can be found in Section 11.

8 METHODOLOGY FOR DETERMINING FAULT LEVEL NODES

The first step in determining the *system strength requirements* is to determine the location of *fault level nodes*. AEMO considers that these should be determined by criteria that would allow maintaining *power system security* and the *system standards*.

AEMO, following consultation with TNSPs, determines that the following classes of *fault level nodes* should be considered.

8.1 Metropolitan Load centres

Metropolitan *Load centres* have very high *load* concentrations that often require stabilisation with switched *reactive power* devices such as shunt capacitor banks and reactors. Hence, it is necessary to maintain minimum fault levels so that switching of capacitor banks or reactors remains stable with *voltage* step changes kept within the limits allowed by the *system standards*. Additionally, increased penetration of power electronic interfaced loads and distributed energy resources such as rooftop photovoltaic (PV) could give rise to similar system strength adverse impacts associated with asynchronous generation if not addressed.

8.2 Synchronous generation centres

It is advisable to consider nodes in a *region* that best represent the *region's* net fault levels from *synchronous generation* contribution, which could be termed the electrical "heart" of the *region*. The purpose of such a node is to give a single *regional* indicator for system strength that would offer an early warning of potential issues and allow recognition of negative trends, such as retirement/displacement of *synchronous generation*.

8.3 Areas with high asynchronous generation connection/interest

Nodes subject to a high concentration of power electronics could suffer instability issues due to:

- a reduction in the local fault level that their *connection* may have triggered due to displacement of Synchronous Machines; and
- a dilution of the fault level for individual converters that becomes shared between increasing concentrations of power electronics.

Examples include North-West Victoria, where there is a large amount of existing and committed solar and wind *generation.*

8.4 Areas electrically remote from synchronous generation

Nodes that are electrically remote from *synchronous generation centres* inherently have low *system strength*. Some of those nodes are also likely to experience a high volume of *asynchronous generation connections* due to the availability of vacant land, favourable wind conditions and solar resource in these areas, therefore, the system strength at these nodes must be maintained at or above a minimum level.

8.5 General consideration for fault level nodes selection

Care should be taken to avoid selecting *fault level nodes* where potential system strength concerns are likely to be local, rather than *regional*, because the economic cost of addressing local system strength issues may not be justified by the limited benefits.

8.6 Fault level nodes for 2018

AEMO determines the location of each *fault level node* in each *region* for 2018 by reference to the criteria in sections 8.1 to 8.4, as follows.

Table 2 Fault level nodes for each region

Fault Level Nodes Class	New South Wales	Victoria	Queensland	Tasmania	South Australia
Metropolitan load centre	Sydney West 330 kV	Thomastown 220 kV	Greenbank 275 kV	Risdon 110 kV	Para 275 kV
Synchronous generation centre	Newcastle 330 kV	Hazelwood 500 kV	Western Downs 275 kV Gin Gin 275 kV	Waddamana 220 kV	Para 275 kV
Areas with high asynchronous generation	Armidale 330 kV Wellington 330 kV Darlington Point 330 kV	Red Cliffs 220 kV Moorabool 220 kV	Nebo 275 kV Lilyvale 132 kV	George Town 220 kV	Davenport 275 kV Robertstown 275 kV
Areas electrically remote from synchronous generation	Darlington Point 330 kV	Red Cliffs 220 kV Dederang 220 kV	Nebo 275 kV Lilyvale 132 kV	Burnie 110 kV	Davenport 275 kV Robertstown 275 kV

9 METHODOLOGY FOR DETERMINING MINIMUM THREE PHASE FAULT LEVELS

AEMO has adopted a two-stage process to assess the *system strength requirements* as follows:

9.1 Stage 1 assessment

The purpose of the Stage 1 studies is to identify *regions* that are not currently considered at risk of a *fault level shortfall*, and to establish a benchmark for comparison in subsequent years. This is achieved by establishing a minimum Synchronous Machine *dispatch* scenario that meets *power system* stability and *system standard* assessment criteria both when the *power system* is intact, and when the largest Synchronous Machine or *transmission element* in a *region* is subject to an *outage*.

The Stage 1 assessment determines the minimum *three phase fault level* at *fault level nodes* for all *regions* as at 30 June 2018. These minimum *three phase fault levels* are calculated based on the minimum Synchronous Machine *dispatch* scenario identified for each *region* for 2018.

For each subsequent year, a Stage 1 assessment will be conducted to indicate whether there is an emerging risk of a *fault level shortfall* in any *region*, either due to previous *system strength requirements* not being maintained by typical patterns of *dispatched generation,* or no longer being adequate to ensure a *secure operating state*, for example, with increased *asynchronous generation* penetration. Once such a risk is identified, the more detailed Stage 2 assessment will be conducted for that *region* as detailed in section 9.2, to determine the exact *system strength requirements*, and the existence and scope of any potential *fault level shortfall*.

Stage 1 is based on RMS analysis methods rather than EMT *power system* dynamic analysis. An example of a Stage 1 assessment can be found in Appendix A.1.

9.1.1 Step 1: Determination of minimum synchronous machine dispatch scenarios

The minimum acceptable combination of Synchronous Machines must satisfy *power system* stability and *system standard* criteria. Four separate outcomes must be met:

1. **Voltage step change limit:**

   Steady state *voltage* change due to *reactive power plant* switching is limited to the requirements set out in *Australian Standard* AS/NZS 61000.3.7:2001.

2. **Generating system fault ride-through capability:**

   Existing *generating systems* are assessed against the impact of the most onerous *credible contingency event* near their *connection points* in accordance with their *performance standards* to ensure they can meet their *performance standard* with respect to their fault ride-through capability.

   The assessment of this criterion can be conducted using the 'Available Fault Level' method developed for the purposes of the *system strength impact assessment guidelines*. The minimum Synchronous Machine *dispatch* scenario must provide positive Available Fault Level at the *connection points* of existing *asynchronous generating systems*.

   A negative Available Fault Level would necessaite a second stage assessment details of which are discussed in Section 9.2.

3. **Correct protection operation:**

   The *three phase fault levels* provided by the minimum Synchronous Machine *dispatch* scenario must allow the TNSPs to maintain correct operation of *protection systems*.

   TNSP may advise specific assessment criteria to be used in assessing *protection system* operation with the minimum Synchronous Machine *dispatch* scenario, and may conduct separate assessment using such assessment criteria.

   In the absence of TNSPs' advice or assessment, the minimum Synchronous Machine *dispatch* scenario must ensure fault current on *transmission lines* and *busbars* will be at least equal to the highest short term emergency rating of the element, unless the *protection system* under assessment currently operates correctly with a fault current of less than 100%.

   When assessing the above criteria, only selected *transmission lines* will be considered, including:

   - *Transmission lines* with sizeable *asynchronous generation connected* to both ends. In this case a *credible contingency event* could result in the *disconnection* of unfaulted line(s) in addition to the faulted line due to incorrect protection operation (maloperation). This causes the *disconnection* of *generation* exceeding the size of the largest permissible *generation* tripping following a *credible contingency event*, where such *disconnection* of *generation* would not occur should the *protection system* operate correctly, and;

- *Transmission lines* where faults are not cleared because of incorrect protection operation (maloperation) causing nearby Synchronous Machines to pole slip as the fault clearance time may exceed the critical clearing time of Synchronous Machines.

4. **Re-assessment of minimum synchronous machines dispatch scenario:**

   The minimum acceptable combination of Synchronous Machines must be re-assessed against the criterion of ensuring correct protection operation under *islanding* conditions for the *region* subject to the following:

   (a) Outcome 1 does not have to be achieved.

   (b) Outcome 2 is not required as certain *generating systems* may be curtailed pre-emptively when there is a credible risk of separation for that *region*.

AEMO has verified that the minimum Synchronous Machine *dispatch* combination can meet criteria 1, 2 and 3, using PSCAD™/EMTDC™ models of the SA *power system* (Appendix A.2 and Appendix C).

- Appendix A.2 demonstrates that when the *power system* is operating with the minimum acceptable Synchronous Machine *dispatch*, outcomes 1 and 2 can be met. When the *power system* is operating with one less Synchronous Machine than the minimum, at least one outcome will not be met (in the example presented in Appendix A.2, outcome 2 is not met).
- Appendix C demonstrates that when the *transmission line* fault current contribution (from either end of the line to the fault location as calculated using PSS®E) is less than 100% of the line's winter rating, it is identified in the PSCAD™/EMTDC™ study that, following certain types of *credible contingency events*, the *transmission line's protection systems* are likely to maloperate. Based on this finding, the minimum acceptable Synchronous Machine *dispatch* scenario must allow the *transmission line* fault current contribution to be at least higher than the highest emergency rating of the line, and this criterion must be met considering N-1 Synchronous Machine *dispatch* or the most critical *transmission element outage* as well.

9.1.2 Step 2: Calculation of the three phase fault level

Static fault current calculations can be used to determine the *three phase fault levels* at each *fault level node* as determined by minimum acceptable Synchronous Machine *dispatch* scenario[11].

Both Synchronous Machines and inverter based *asynchronous generation* provide fault current to the *power system*. Synchronous Machines generally make a positive contribution to the total fault level in the *power system* and system strength. For this reason, they can be considered to be sources of fault current. While *asynchronous generation* also contributes positively to the total fault level, it, effectively, acts as a sink for system strength.

Practical experience with the *connection* of new *asynchronous generation* near existing *asynchronous generation* indicates that it could degrade the performance of the existing *asynchronous generation* even though the total *three phase fault level* (including fault current contribution from the new *asynchronous generation*) would increase. Including the fault current contribution from *asynchronous generation* in calculating the *three phase fault levels* would result in a higher *three phase fault level*, however, this does not mean that system strength has increased. Therefore, while the fault level is commonly used as a simplified proxy for system strength, care must be exercised not to include the fault current contribution of *asynchronous generation* in determining the *system strength requirements.*

This is important because grid following inverter technologies currently predominate in the *NEM*. The use of grid forming technology in *asynchronous generating systems* would provide a positive contribution to both the fault level and system strength and should, therefore, be included in the total fault level calculations.

Therefore, the Stage 1 studies will result in the calculation of the minimum *three phase fault levels* at each *fault level node* with contributions from Synchronous Machines only.

[11] AEMO has used the automatic sequencing fault calculation (ASCC) methods in PSS®E.

The following model adjustment method is developed to represent the fault current contribution from Synchronous Machines only:

(a) Any *asynchronous generation*, such as WTGs or solar inverters or battery storage systems will be replaced by negative *loads*, with the *load* MW and MVAr matching the negative values of the MW and MVAr *generation* being replaced.

(b) Any FACTS device modelled as a *generating unit* in PSS®E will be replaced by a fixed shunt, with the MVAr value of the fixed shunt matching the MVAr output of the *generating unit* being replaced.

9.1.3 Step 3: Trigger for Stage 2 assessment

For 2018, the minimum Synchronous Machine *dispatch* scenarios were identified in Step 1 for each *region* other than SA, where the minimum Synchronous Machine *dispatch* scenarios were identified by a Stage 2 assessment, for which a detailed system strength assessment is presented in the South Australia System Strength Assessment (**SASSA**). Using the minimum Synchronous Machine *dispatch* scenarios identified above for each *region,* the outcomes of Step 2 are the minimum *three phase fault levels* at *fault level nodes* for each *region* for 2018*.* The minimum *three phase fault levels* for 2018 are the benchmark *system strength requirements* to be compared for any subsequent year.

For any subsequent year, the outcome of Step 2 could trigger a more detailed Stage 2 assessment if either of the following triggering conditions is met:

- Condition 1: for any *fault level node*, *three phase fault levels* calculated using the current year's typical patterns of *dispatched generation* is lower than the previous year's minimum *three phase fault levels*.
- Condition 2: for *any fault level node*, *three phase fault levels* calculated using the current year's minimum Synchronous Machine *dispatch* is higher than the previous year's minimum *three phase fault levels.*

Condition 1 indicates that the minimum *three phase fault levels* at the *fault level nodes* cannot be maintained by the typical Synchronous Machine *dispatch* pattern. Such a gap might be caused by Synchronous Machine retirement or displacement due to increased *asynchronous generation* penetration. This further indicates an emerging risk of a *fault level shortfall*, necessitating a more detailed Stage 2 assessment to confirm its existence and scope.

The *three phase fault level* at some *fault level nodes* could reduce due to the use of a different Synchronous Machine *dispatch* pattern in subsequent years when calculating minimum *three phase fault levels* while meeting all *power system* stability and *system standard* criteria, as discussed in section 9.1.1. In this case, a Stage 2 assessment will be conducted to confirm the *system strength requirements.*

Condition 2 indicates that the minimum *three phase fault levels* at the *fault level nodes* are likely to be higher than the previous year's levels. Such an increase could be the result of increased penetration of *asynchronous generation*, which requires more Synchronous Machines to be *dispatched* to maintain stable operation. In this case, a Stage 2 assessment will be conducted to confirm the *system strength requirements*, and whether there is any *fault level shortfall* based on the current availability of Synchronous Machines.

A detailed description of the Stage 2 assessment, including its tools and methodology, can be found in Section 9.2.

9.1.4 Minimum three phase fault levels for 2018

For Queensland, New South Wales, Victoria, and Tasmania, the minimum *three phase fault levels* for 2018 at each *fault level node* has been calculated using the:

- minimum Synchronous Machine *dispatch* scenario proposed by each SSSP that can achieve the outcomes detailed in section 9.1.1; and
- *three phase fault level* calculation method described in section 9.1.2, using the above Synchronous Machine *dispatch* scenario.

For SA, the minimum *three phase fault level* at each *fault level node* for 2018 has been calculated using the:

- minimum Synchronous Machine *dispatch* scenarios identified in the SASSA; and
- *three phase fault level* calculation method described in Section 9.1.2, using the *dispatch* scenario (among other scenarios identified in the SASSA) that produce the minimum *three phase fault levels* at each *fault level node.*

9.1.5 Planning horizon

For the *system strength requirements* to be *published* by 30 June 2018, the determination of *three phase fault levels* can only consider the state of the current *power system*.

For *system strength requirements* to be *published* with the 2019 *NTNDP* and subsequent years, the Stage 1 assessment will be conducted within a planning horizon of 5 years including the current year, considering:

- Synchronous Machine retirement;
- all *generation connections* for each year under assessment; and
- the Synchronous Machine *dispatch* scenarios over the entire five-year horizon is assumed to be the same as per the current year (1st year in the planning horizon), minus any Synchronous Machines that are expected to retire over that period.

9.2 Stage 2 assessment

AEMO will prioritise the Stage 2 assessments based on the timeframe in which a *region* is likely to approach a *fault level shortfall*. This timeframe is likely to be driven by the rate of *connection* of *asynchronous generation* in the absence of other developments that improve system strength.

An example of a Stage 2 assessment can be found in Appendix A.2.

9.2.1 Detailed EMT type analysis for Stage 2 assessment

The Stage 2 assessment will be conducted using the same methodology described in the SASSA, and will yield more granular *three phase fault levels* considering all aspects of *power system security*.

AEMO will use detailed PSCAD™/EMTDC™ studies to confirm the minimum acceptable Synchronous Machine *dispatch* scenarios and the minimum *three phase fault levels* to ensure the operation of a *region's power system* if all outcomes are met following a single *credible contingency event* or *protected event*.

Stage 2 will also be used as a pre-requisite to confirm the extent of any *fault level shortfall* in sufficient detail for SSSPs to procure *system strength services* as required by clause 5.20C.2 of the NER.

9.2.2 Considerations for Stage 2 assessment

Stage 2 includes assessment of the following:

1. *Disconnection* of the largest Synchronous Machine following a *credible contingency event* or *protected event*. Being the largest contributors to a *region's* system strength, they could impact the maximum size of *load shedding* or *generation shedding* expected to occur on the occurrence of any *credible contingency event* or *protected event* affecting the *region*[12]; and
2. A *credible contingency event* or *protected event* where:
   (a) any equipment that is materially contributing to the *three phase fault level* is *disconnected*, or becomes unstable following the event; or
   (b) there is a risk of cascading *outages* as a result of any *load shedding* or *generating system* or *market network service facility* tripping.

Therefore, Stage 2 must consider the availability of *synchronous generating units* and any other *facility* or service that is material to the *three phase fault level*, as well as the need for additional contributions to the *three phase fault level* and its availability[13] when such *synchronous generating units*, *facilities* or services are not available.

[12] Clause 5.20.7(b)(2)
[13] Clause 5.20.7(b)(4) to clause 5.20.7(b)(6)

The Stage 2 assessment will include all existing and committed *generating systems* for each assessment year. The criteria for considering a proposed *connection* 'committed' is consistent with those specified in the *system strength impact assessment guidelines*.

9.2.3 Success criteria

The following criteria will be used to determine whether a Synchronous Machine *dispatch* scenario is sufficient for a *region's power system* to remain in a *secure operating state*[14] following a *credible contingency event* or *protected event:*

- *asynchronous generation* remains online, except for that in electrically distant portions of the *network* and where the impact on *power system security* is negligible;
- all *synchronous generation* in the scenarios studied returns to steady-state conditions following fault clearance;
- the *region* remains *connected* to the remainder of the *NEM*; and
- the *transmission network voltages* across the *region* return to *nominal voltages*.

The above criteria are consistent with the success criteria considered in section 3.7 of SASSA.

The criteria listed in Section 9.1.1 must also be met before a Synchronous Machine *dispatch* scenario will be acceptable for the provision of sufficient system strength to withstand a *credible contingency event* or *protected event*.

9.2.4 Minimum three phase fault level following Stage 2 assessment

Following completion of the Stage 2 assessment, the calculation of the minimum *three phase fault level* at each *fault level node* in a *region* will be based on:

- The minimum Synchronous Machine *dispatch* scenarios identified following the Stage 2 assessment; and
- Using these scenarios, if all success criteria are met, the *three phase fault level* at each *fault level node* can be calculated using PSS®E and the methodology described in Section 9.1.2. The minimum *three phase fault level* can then be determined based on the lowest calculated *three phase fault level* across the Synchronous Machine *dispatch* scenarios*.*

The Stage 2 assessment will be used to determine the minimum *three phase fault level* for SA, as well as for all other *regions* in subsequent years when a Stage 2 assessment is triggered.

10 MINIMUM THREE PHASE FAULT LEVELS FOR 2018

Using the Methodology, the minimum *three phase fault levels* were identified at each *fault level node* for each *region*.

Table 3 Minimum three phase fault levels at fault level nodes in each region for 2018

Region	Fault Level Nodes	Minimum Three Phase Fault Level (MVA)
South Australia	Davenport 275 kV	1150
	Robertstown 275 kV	1400
	Para 275 kV	2200
Tasmania	George Town 220 kV	1450
	Waddamana 220 kV	1400
	Burnie 110 kV	750
	Risdon 110 kV	1330
Queensland	Western Downs 275 kV	2550
	Greenbank 275 kV	3800
	Nebo 275 kV	1750

[14] Clause 5.20.7(b)(1), 5.20.7(b)(3), 5.20.7(b)(4) and 5.20.7(b)(6)

Region	Fault Level Nodes	Minimum Three Phase Fault Level (MVA)
	Gin Gin 275 kV	2400
	Lilyvale 132 kV	1100
New South Wales	Armidale 330 kV	3000
	Sydney West 330 kV	9250
	Wellington 330 kV	1900
	Newcastle 330 kV	8400
	Darlington Point 330 kV	1550
Victoria	Hazelwood 500 kV	8850
	Dederang 220 kV	3500
	Thomastown 220 kV	4100
	Red Cliffs 220 kV	600
	Moorabool 220 kV	4400

11 DETERMINING FAULT LEVEL SHORTFALLS

11.1 Identification of fault level shortfall following Stage 1

As Stage 1 utilises a simple static fault current calculation method, it is less likely to identify a *fault level shortfall* but could indicate the risk of an emerging *fault level shortfall*.

Either of these two factors can be considered to be a strong indication of a *fault level shortfall* in Stage 1:

1. Retirement of Synchronous Machines.
2. High penetration and *dispatch* of *asynchronous generation* offsetting Synchronous Machine *dispatch*.

If a *fault level shortfall* is identified at a designated *fault level node*, the proposed solution can be introduced at the *fault level node* itself, or any other more suitable node in the same *transmission network*.

11.2 Identification of fault level shortfall in Stage 2 assessment

The *fault level shortfall* can be quantified using the *three phase fault level* (measured in MVA) following the completion of Stage 2 assessment.

The *fault level shortfall* will be the difference between the minimum *three phase fault level* determined by the acceptable Synchronous Machine *dispatch* scenarios in Stage 2, and the *three phase fault level* determined by typical *generation dispatch* patterns. A *generation dispatch* pattern can be considered as a typical *dispatch* pattern if the resulting *three phase fault level* at the *fault level nodes* can be maintained for majority of the year.

The Stage 2 assessment can only be used to confirm the existence and extent of a *fault level shortfall* in a *region* covering a timeframe of up to two years only. This is because of the uncertainty of *generation connections* within a five-year timeframe that will require extensive assumptions to be applied in the PSCAD™/EMTDC™ models, such as change in the project schedule for committed *generation*, and advancements in *generation* technology, particularly inverter based technology, which make the Stage 2 analysis an unreliable and unnecessarily complex indicator of potential *fault level shortfalls* for the entire five-year planning horizon.

11.3 Fault level shortfall as of June 2018

There is currently no *fault level shortfall* in any *region* in the *NEM*, other than SA.

AEMO has conducted detailed system strength assessments for the SA *power system*, and identified several minimum Synchronous Machine *dispatch* scenarios in the SASSA.

In December 2016, AEMO's National Transmission Network Development Plan (**NTNDP**) identified an NSCAS gap for system strength in SA. Subsequently AEMO declared a system strength NSCAS gap in

South Australia in October 2017 and confirmed the exact extent of the gap. ElectraNet is required to provide the necessary *system strength services* to remedy the existing shortfall. In the interim, the shortfall is being managed by AEMO through operational measures including, where necessary, issuing *directions* for the *dispatch* of *synchronous generating units* to meet the minimum Synchronous Machine *dispatch* scenarios.

Using the Methodology, *fault level shortfalls* were identified in SA. Details of the *fault level shortfall* can be found in Section 11.3.1. This is consistent with the size of *fault level shortfalls* declared previously.

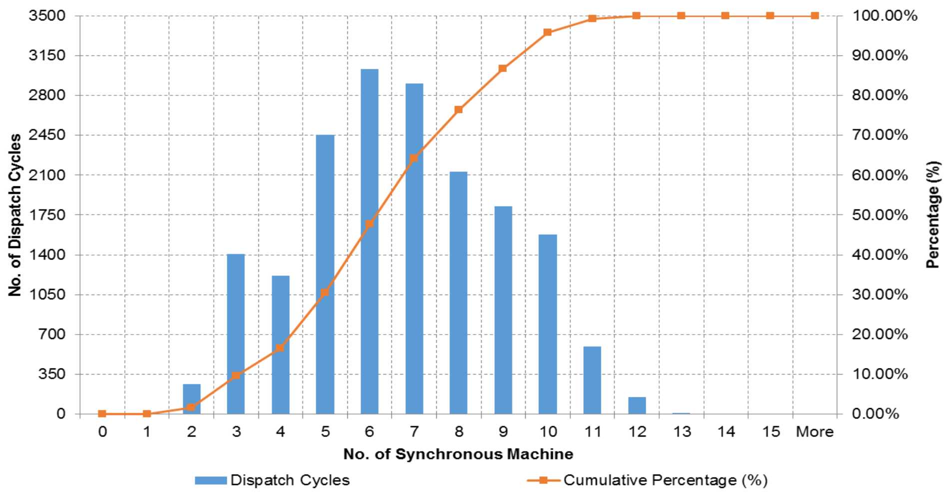
The studies presented in this document were carried out on both the *interconnected* SA *power system* as well as during *islanding* conditions to ensure that system strength can be maintained under all operating conditions.

11.3.1 Investigation of fault level shortfall in South Australia

AEMO currently *directs synchronous generation* in SA to maintain sufficient system strength based on the minimum *synchronous generation dispatch* combination published in the Transfer Limit Advice[15].

Figure 2 and Figure 4 show the shift of *synchronous generation dispatch* patterns before (FY 2017) and after (FY 2018) the commencement of AEMO's *direction*. Prior to AEMO's *direction*, the minimum number of *synchronous generating units dispatched* was one, with an average of around six *synchronous generating units*.

Figure 2 Historical Synchronous Machine dispatch in SA (FY 2017)



Historical *three phase fault levels* (with Synchronous Machine contribution only) at the *fault level nodes* in SA can be calculated for FY 2017 prior to AEMO's *direction*, and calculated *three phase fault levels* for November 2016 are presented in the following figure, with comparison against the minimum *three phase fault levels* determined using the Methodology.

15 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf

Figure 3 Historical fault level shortfall in SA without AEMO Direction (November 2016)

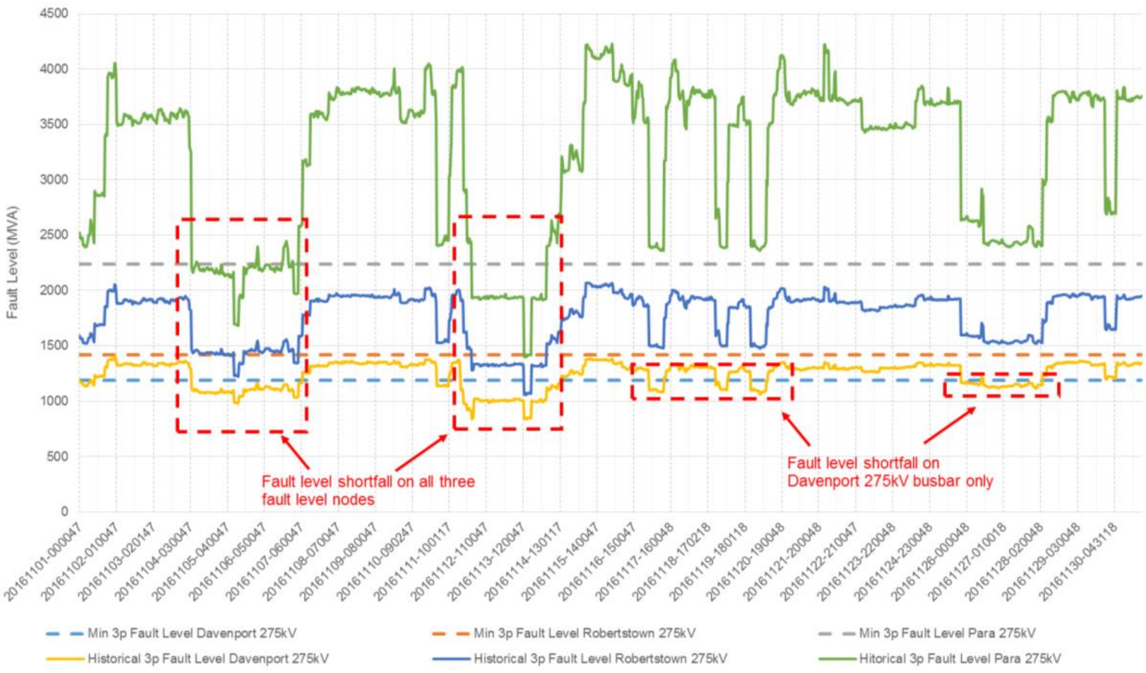


Figure 3 shows that in November 2016, *fault level shortfalls* were identified at all three *fault level nodes* in SA for 7 days, and a further 6 days of *shortfalls* on Davenport 275 kV *busbar* only. The largest *fault level shortfall* at each fault level node in terms of *three phase fault level* in MVA are listed in the following table.

Table 4 Largest *fault level shortfall* in South Australia

Fault Level Node	Largest Fault level shortfall (MVA)
Davenport 275 kV	350
Robertstown 275 kV	360
Para 275 kV	840

The existing *fault level shortfall* from normal *dispatch* patterns would be identified when the loading in the SA *power system* is relatively low, such as November. This is because during low loading conditions, the energy demand–supply balance would not cause a large number of *synchronous generating units* to be *dispatched* to meet demand, which would otherwise shield the existing *fault level shortfall*.

It should be noted that a comparison of historical *three phase fault levels* against the minimum *three phase fault levels* was not provided for the entire FY 2017, due to the SA *black system* event in September 2016 and the subsequent market suspension in SA.

Following the detailed system strength assessment in the SASSA, AEMO seeks to ensure the minimum acceptable Synchronous Machine *dispatch* scenarios are met in SA at all times, including by issuing *directions* for relevant *synchronous generating units* in SA to operate. With such *directions*, the minimum number of *synchronous generating units dispatched* was four, with an average of around seven *synchronous generating units* in FY 2018, as shown in Figure 4.

Figure 4 Historical Synchronous Machine dispatch in SA (FY 2018)

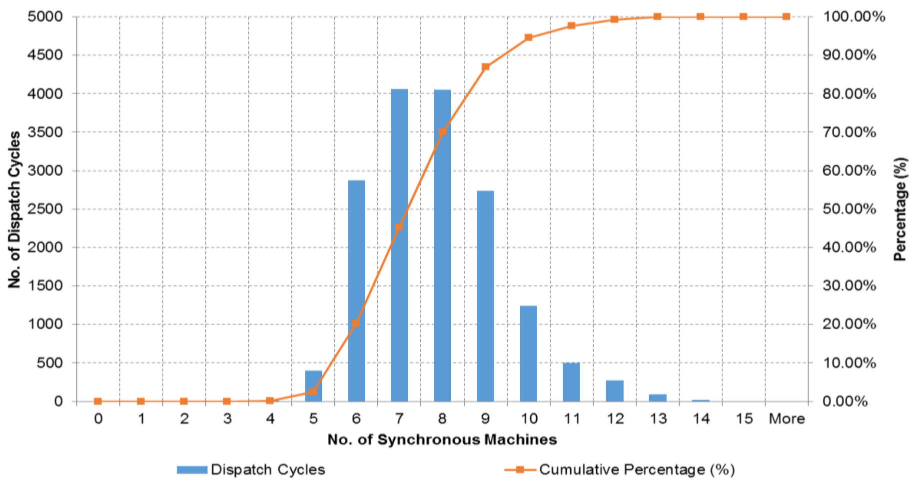
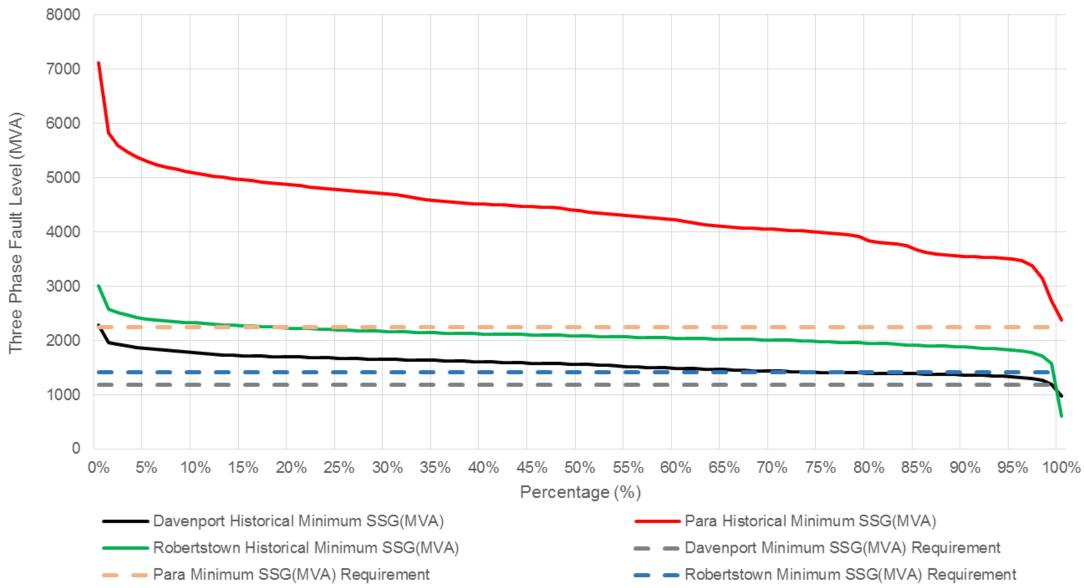


Figure 5 shows a comparison between the historical minimum *three phase fault level* in FY 2018 and the minimum *three phase fault level* requirement at each *fault level node* in SA.

Figure 5 Comparison between Historical Fault Level with Minimum Three Phase Fault Level in SA



The historical minimum *three phase fault levels* (maintained for 99% of the year) are tabulated in Table 5 along with the minimum *three phase fault levels* to be maintained at each *fault level node*.

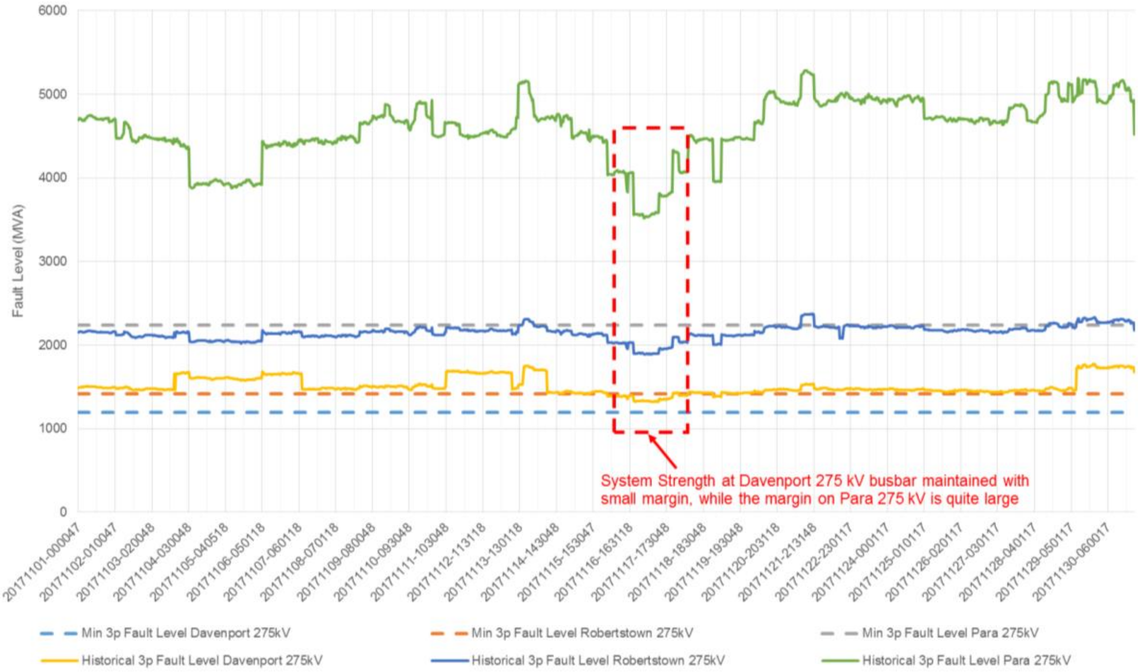
Table 5 Historical minimum three phase fault level compared with minimum three phase fault level requirement

Fault Level Node	Minimum Three Phase Fault Level Requirement (MVA)	Historical Minimum Three Phase Fault Level FY 2018 (MVA)
Davenport 275 kV	1150	1224
Robertstown 275 kV	1400	1659
Para 275 kV	2200	2800

Figure 5 and Table 5 show that for the entire FY 2018, the *three phase fault levels* at Para were maintained above the minimum *three phase fault level*. The *three phase fault levels* at Davenport and Robertstown were maintained above the minimum *three phase fault levels* for 99% of the year.

Figure 6 shows a similar comparison to the one presented in Figure 3, between the historical *three phase fault level* and the minimum *three phase fault levels* at the *fault level nodes* in SA in November 2017. Compared with November 2016 where *fault level shortfalls* were observed for an extended period, the system strength in SA in November 2017 was maintained through AEMO's *direction.* It could be seen in Figure 6 that the system strength at Para 275 kV was maintained with large margin, while the margin at Davenport 275 kV is small. This is expected because Davenport 275 kV *busbar* is further away from Synchronous Machine centres than Para 275 kV *busbar*. More Synchronous Machines need to be *dispatched* to meet the minimum *three phase fault level* at Davenport 275 kV *busbar* than the number of Synchronous Machines required to meet the minimum *three phase fault level* at Para 275 kV *busbar* only. This further suggests that having Synchronous Machines near the Davenport 275 kV *busbar* could see system strength being maintained at both Davenport and Para with a reasonable margin.

Figure 6 System strength in SA in November 2017, maintained by AEMO's Direction



In summary, since AEMO implemented the current operational measures to maintain minimum combinations of *synchronous generation* online, the *three phase fault levels* at each *fault level node* have been maintained above the minimum *three phase fault levels*, managing the existing *fault level shortfalls*.

ElectraNet, as the SSSP in SA, is expected to provide *system strength services* in due course to remedy the existing *fault level shortfalls*.

APPENDIX A. PRACTICAL EXAMPLES

Two examples are provided to demonstrate the implementation of the Methodology.

A.1 Example of Stage 1 assessment

The following example demonstrates the implementation of the Stage 1 assessment for the Tasmania *power system*, where the minimum *three phase fault levels* have been determined at the *fault level nodes* for 2018.

A.1.1 Existing limit advice for George Town 220 kV substation

Based on the current limit advice from TasNetworks, sufficient fault level must be maintained at the George Town 220 kV Substation to ensure stable operation of the Basslink HVDC *interconnector*. AEMO is currently managing existing *constraint* equations for the fault level at George Town to ensure that the SCR is maintained above the minimum value advised by Basslink's manufacturer. The minimum *three phase fault level* at George Town currently being maintained for Basslink operation is 1450 MVA.

A.1.2 Minimum three phase fault level for capacitor bank switching at Risdon 110 kV substation

Two capacitor banks (40 MVAr each) are installed at the Risdon 110 kV *busbar,* which has been selected as a *fault level node*.

For these two capacitor banks, the *system standards* specify a maximum *voltage* step change following capacitor bank switching to be 3% of the *nominal voltage*. To achieve this, a *three phase fault level* at Risdon must be maintained, which can be calculated using the following equation:

$$Minimum\ Three\ Phase\ Fault\ Level\ (MVA) = Capacitor\ Bank\ Rating\ (MVAr) \div \Delta\, V(pu)$$

For a 40 MVAr capacitor bank with a 3% *voltage* step change limit, the *three phase fault level* to be maintained at Risdon is calculated to be 1333 MVA.

A.1.3 Step 1: Determination of minimum synchronous machine dispatch scenario

A set of Synchronous Machine *dispatch* scenarios has been selected by TasNetworks, which will provide the minimum *three phase fault level* needed to fulfil the above fault level requirement at George Town 220 kV and Risdon 110 kV Substations.

A PSS®E steady state fault current calculation was carried out using the proposed Synchronous Machine *dispatch* to calculate the total *three phase fault level* at Risdon and George Town. The PSS®E model used in such a calculation was adjusted using the model adjustment method described in Section 9.1.2. The calculated steady state fault currents are shown in Table 6.

Table 6 Calculated three phase fault level compared with three phase fault level required to meet existing limits

Fault Level Node	Calculated Three Phase Fault Level in PSS®E (MVA)	Three Phase Fault Level required to meet existing limits (MVA)
George Town 220 kV	1452	1450
Risdon 110 kV	1330	1333

Table 6 shows that the corresponding fault levels calculated in PSS®E are very close to the minimum *three phase fault level* determined by the current limit advice (for the George Town 220 kV *busbar*), and power quality requirement (Risdon 110 kV *busbar*). The selected Synchronous Machine *dispatch* is then used for further assessment against all three criteria listed in Section 9.1.1.

A.1.4 Assessment of voltage step change limit

PSS®E load flow switching analysis was conducted with the selected Synchronous Machine *dispatch* to calculate the *voltage* step change at Risdon 110 kV following the capacitor bank switching. The switching results shows that prior to capacitor bank switching, the *voltage* at the Risdon 110 kV *busbar* is 1.0234 pu. After the capacitor bank switching (with all *transformer* taps locked), the *voltage* at Risdon is 1.0445 pu. The steady state *voltage* step change is 2.1% which is smaller than the required 3%.

This assessment indicates that with the selected Synchronous Machine *dispatch*, the *voltage* step change limit at the Risdon 110 kV *busbar* following the switching of a 40 MVAr capacitor bank can be maintained, thus meeting the *voltage* step change criteria.

A.1.5 Assessment of generating system fault ride-through

Three wind farms are *connected* to the Tasmanian *power system*; Bluff Point, Studland Bay and Musselroe. Musselroe Wind Farm has *synchronous condensors* on site and local system strength is maintained through those. Hence, the assessment in this example focusses on the other two wind farms, which are *connected* to northwest corner of the *network*.

There is no PSS®E model available for Bluff Point Wind Farm or Studland Bay Wind Farm, so the assessment was carried out using the minimum SCR required for stable operation of the wind farms and the 'Available Fault Level' method developed for the purposes of the *system strength impact assessment guidelines*.

TasNetworks advised that a minimum aggregate SCR of 3.0 at the Smithton 110 kV Substation is currently maintained considering both wind farms. This aim further targets minimum SCRs of 2 at the *connection points* of both Studland Bay and Bluff Point wind farms.

A historical fault recording has been provided by TasNetworks to demonstrate the wind farm fault ride-through capability when the *power system* is operating with an aggregate SCR of 3.0 at the Smithton 110 kV Substation, and correspondingly SCR of 2 at the wind farm *connection points*, as per TasNetwork's target. The *three phase fault level* at Smithton 110 kV *busbar* prior to the contingency was around 419 MVA, which shows that SCR of 3 (total MW rating of wind farms being 140 MW) at Smithton 110 kV *busbar* was maintained. In Figure 7, the wind farms successfully rode through the fault, and their MW output was gradually run back due to the tripping of the Smithton–Burnie 110 kV circuit causing the SCR at Smithton to be lower than 3. This fault recording demonstrates that the wind farms can ride through a *credible contingency event* (single-phase-to-ground fault as in the fault recording), with the *power system* operating at the target SCR level at Smithton 110 kV.

Using the selected Synchronous Machine *dispatch* and the above minimum SCR requirement, the Available Fault Levels were calculated at the of Studland Bay and Bluff Point *connection points* in PSS®E, which are presented in Table 7:

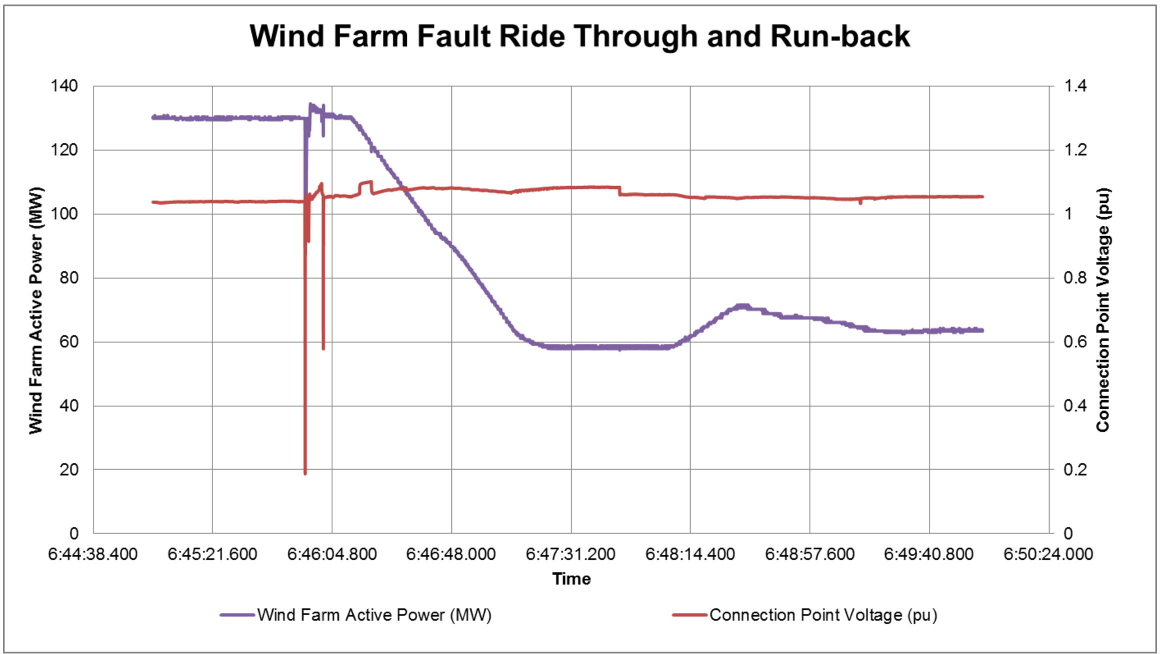
Table 7 Available Fault Levels at Bluff Point Wind Farm and Studland Bay Wind Farm

Wind Farm	S_{SG}(MVA)	S_{Total}(MVA)	Δ (S_{Total}(MVA) - S_{SG}(MVA))	Available Fault Level (S_{SG}(MVA) – Δ)
Bluff Point	260	492	232	+28
Studland Bay	268	512	244	+24

Table 7 shows that the Available Fault Levels are both positive, indicating that both wind farms can maintain stable operation following credible contingency events, as the required minimum SCR has been met by the selected Synchronous Machine *dispatch* scenario.

It is considered that the criterion of *generating system* fault ride-through has been met by the selected Synchronous Machine *dispatch*.

Figure 7 Bluff Point and Studland Bay Wind Farm fault ride-through with minimum fault level



A.1.6 Assessment of protection operation limits

TasNetworks maintains and publishes a set of *three phase fault levels* at each *transmission* substation for assessment of protection limits in its Annual Planning Report (**APR**). TasNetwork refers to these *three phase fault levels* for protection design purposes, as the least amount of fault levels required in order for the protection system to operate. The *three phase fault levels* with the selected Synchronous Machine *dispatch* were calculated using PSS®E, and then compared with the published *three phase fault level* at *each fault level node*.

The wind farm fault current contribution is not included in the above fault level calculation. This does not affect the assessment of protection operation limits, as the actual fault current measured by the *protection systems* will be higher than the calculated fault level, with fault current contribution from the wind farms. If the protection operation limits can be met by the calculated fault current in PSS®E, it will be met by the actual measured fault current.

The comparison between the calculated fault levels and the published minimum *three phase fault levels* are presented in Table 8.

Table 8 Tasmanian power system minimum fault levels for protection operation assessment

Fault Level Node	Calculated Three Phase Fault Level in PSS®E (MVA)	APR Minimum Fault Level (MVA)
George Town 220 kV	1452	1181
Waddamana 220 kV	1400	1181
Burnie 110 kV	750	457
Risdon 110 kV	1330	972

Table 8 shows the calculated *three phase fault levels* at each *fault level node* with Synchronous Machine fault current contribution only, which are higher than the *three phase fault levels* published in TasNetworks' APR. This suggests that the selected minimum Synchronous Machine *dispatch* can maintain sufficient *three phase fault levels* to allow proper protection operation in the Tasmanian *power system*.

A.1.7 Step 2: Determination of minimum three phase fault level at Tasmania for 2018

The above assessments demonstrate that the selected Synchronous Machine *dispatch* scenario can meet all three criteria listed in Section 9.1.1, and can be used for determining the minimum *three phase fault level* at the *fault level nodes*.

The minimum *three phase fault level* at the George Town 220 kV *fault level node* is determined to be 1450 MVA, which is the *three phase fault level* required for the stable operation of Basslink.

The minimum *three phase fault level* at the Risdon 110 kV *fault level node* is determined to be 1330 MVA, which is the *three phase fault level* required to maintain steady state *voltage* step change limit following a capacitor bank switching.

For Burnie 110 kV and Waddamana 220 kV *fault level nodes*, the minimum *three phase fault levels* are based on the calculated *three phase fault levels* in PSS®E, using the minimum Synchronous Machine *dispatch* scenario. Table 9 shows the minimum *three phase fault levels* determined in TAS for 2018:

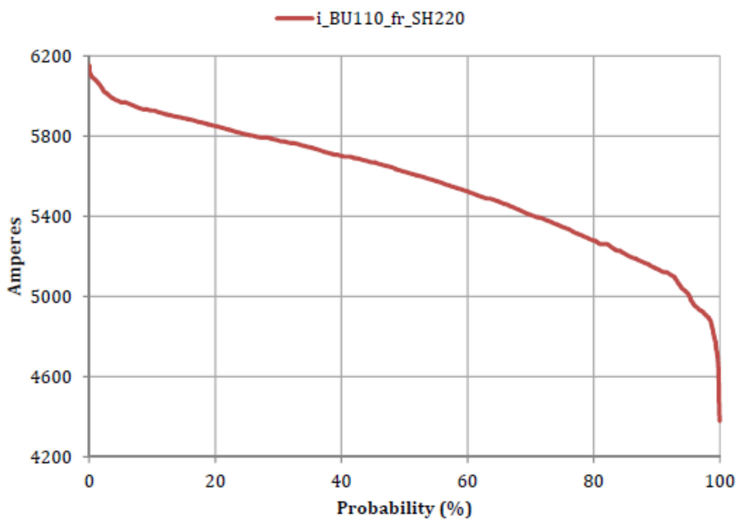
Table 9 Minimum three phase fault level for Tasmania for 2018

Fault Level Node	Minimum Three Phase Fault Level (MVA)
George Town 220 kV	1450
Waddamana 220 kV	1400
Burnie 110 kV	750
Risdon 110 kV	1330

A.1.8 Step 3: Investigation for potential fault level shortfalls

TasNetworks provided historical *three phase fault levels* observed at each *fault level node* in the form of cumulative probability curves. The historical *three phase fault levels* were calculated considering wind farm fault current contribution. An example is shown for the Burnie 110 kV *fault level node*:

Figure 8 Cumulative probability of fault current at Burnie 110 kV busbar



As shown in Figure 8, the historical minimum *three phase fault current* at Burnie is around 4400 A, which is equal to a *three phase fault level* of 838 MVA. For 99% of the time, the fault level can be maintained at above 900 MVA. These are both higher than the minimum *three phase fault level* requirements at Burnie, which is 750 MVA.

Historical minimum *three phase fault levels* at *each fault level node* are listed in Table 10.

Table 10 Comparison between historical minimum three phase fault level and minimum three phase fault level requirement

Fault Level Node	Minimum Three Phase Fault Level requirement (MVA)	Historical Minimum Three Phase Fault Level for 99% of the time (MVA)
George Town 220 kV	1450	2100
Waddamana 220 kV	1400	2300
Burnie 110 kV	750	900
Risdon 110 kV	1330	1700

Table 10 shows that the *three phase fault levels* historically maintained by TasNetworks are higher than the minimum *three phase fault levels* required at each *fault level node*. It indicated that there is no *fault level shortfall* for Tasmania.

A.2 Example of Stage 2 assessment

This Appendix presents practical examples of the Stage 2 assessment for the SA *power system*.

For brevity, the simulation studies presented are for assessing the three success criteria discussed in Section 9.1.1. Assessment against the additional criteria discussed in Section 9.2.3 can be found in SASSA (for system intact conditions) and AEMO's South Australia Power System Operation as a Viable Island report[16] (for *islanding* conditions).

PSCAD™/EMTDC™ studies were conducted using detailed EMT simulations to assess whether the minimum Synchronous Machine *dispatch* combinations identified in SASSA would allow criteria 1 and 2 to be met. Criterion 3 is assessed in Appendix C. The remainder of this Appendix documents the details of these studies and the outcome. The PSCAD™/EMTDC™ model developed for the SASSA studies was used for the studies documented in this Appendix.

A.2.1 Assessment Method

For the *voltage* step limit criterion, the largest capacitor or reactor installed at each *fault level node* is switched in or out of service, and steady state *voltage* step changes are monitored. To meet this criterion, the *voltage* step change should not exceed the steady state *voltage* step change limit specified in the *system standards*. Where SA is *islanded*, the capacitor or reactor switching was performed after a stable *island* had been established.

For *generating system* fault ride-through performance, faults close to *asynchronous generation* were applied and the capability of different *asynchronous generation* to ride through these faults was assessed against their *performance standards*. Two fault locations were selected, one at Davenport 275 kV and the other at Yadnarie 132 kV *busbars*, both close to the *connection points* of several wind farms.

The Davenport 275 kV *busbar* was selected as several large wind farms *connected* near this location are required to ride through three phase faults in accordance with their *performance standards*. A three phase fault was applied at this location in the studies.

The Yadnarie 132 kV *busbar* was selected to investigate whether certain wind farms that are electrically remote from *synchronous generation centres* and where the system strength is inherently low could meet their *performance standards*. A two-phase-to-ground fault was applied at Yadnarie 132 kV *busbar*, as most wind farms *connected* near this location are only required to ride through two-phase-to-ground faults.

These studies were conducted in system normal conditions with SA *connected* to the rest of the *NEM*, and with SA as an *island*. For simplicity, only the Low 5 (listed in Transfer Limit Advice[17]) *dispatch* scenario was investigated in the studies summarised in Table 11.

[16] Available at http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/SA_Operation_as_viable_Island_report_PUBLISHED.pdf

[17] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf

Table 11 Summary of validation studies for selection criteria.

Synchronous Generation Dispatch Combination	Disturbance Applied	Criteria Assessed
Minimum acceptable combinations identified in SASSA	50 MVAr reactor switching at Davenport bus.	Voltage step change (criterion #1)
	100 MVAr capacitor switching at Para 275 kV bus.	
	Three phase fault at Davenport 275 kV *busbar*, cleared by primary protection.	*Performance standard* compliance (criterion #2)
	Two phase to ground fault at Yadnarie 132 kV *busbar*, cleared by primary protection.	
The largest *synchronous generating unit* out of service in the minimum acceptable combinations identified in SASSA	50 MVAr reactor switching at Davenport bus.	*Voltage* step change (criterion #1)
	100 MVAr capacitor switching at Para 275 kV bus.	
	Three phase fault at Davenport 275 kV *busbar*, cleared by primary protection.	*Performance standard* compliance (criterion #2)
	Two phase to ground fault at Yadnarie 132 kV *busbar*, cleared by primary protection.	

A.2.2 Assessment results with system normal condition

The following sections described the assessment results during an SA system normal condition. The study results were compared with the corresponding selection criteria to determine whether each criterion can be met.

For the *voltage* step change limit scenario, a 3% *voltage* step change limit was selected for both capacitor switching at Para 275 kV and reactor switching at Davenport 275 kV *busbars*.

A.2.2.1 Reactive power plant switching

Para 275 kV 100 MVAr capacitor switching

With the minimum acceptable *synchronous generation dispatch* combinations previously identified in SASSA, the capacitor bank switching at the Para 275 kV *busbar* will not cause the steady state *voltage* step change to exceed 3%. A less than 2% *voltage* change was observed as shown in Figure 9.

A similar *voltage* step change was observed when the *power system* is operating with the largest *synchronous generating unit* out of service in the minimum acceptable *synchronous generation dispatch* combination (Figure 10).

These results demonstrated that the minimum *synchronous generation dispatch* combination in SA can meet the *voltage* step change limit criterion. This criterion can also be met when the SA *power system* is operating with one less *synchronous generating unit.*

Figure 9 Para 275 kV bus voltage (minimum synchronous generation dispatch)

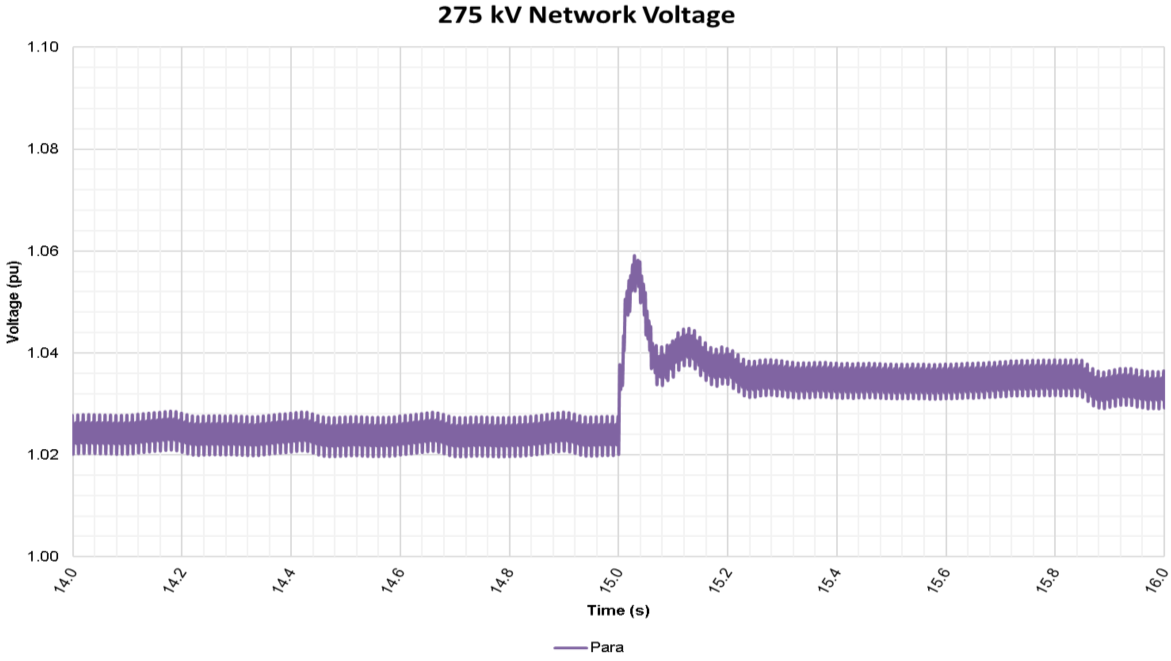
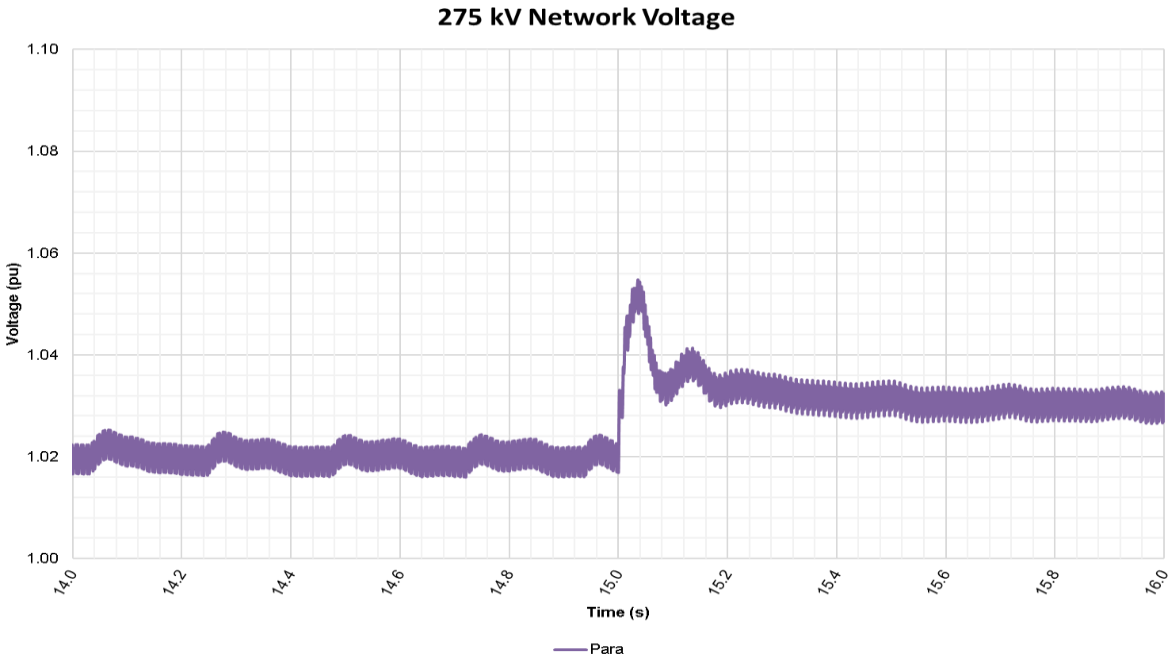


Figure 10 Para 275 kV bus voltage (minimum synchronous generation dispatch, with the largest synchronous generating unit out of service)



Davenport 275 kV 50 MVAr reactor switching

Similar to the results for capacitor bank switching at Para 275 kV, the reactor switching out of service at the Davenport 275 kV *busbar* resulted in a *voltage* step change of around 2%, meeting the criterion of maximum 3% steady state *voltage* step change.

Figure 11 Davenport 275 kV bus voltage (minimum synchronous generation dispatch)

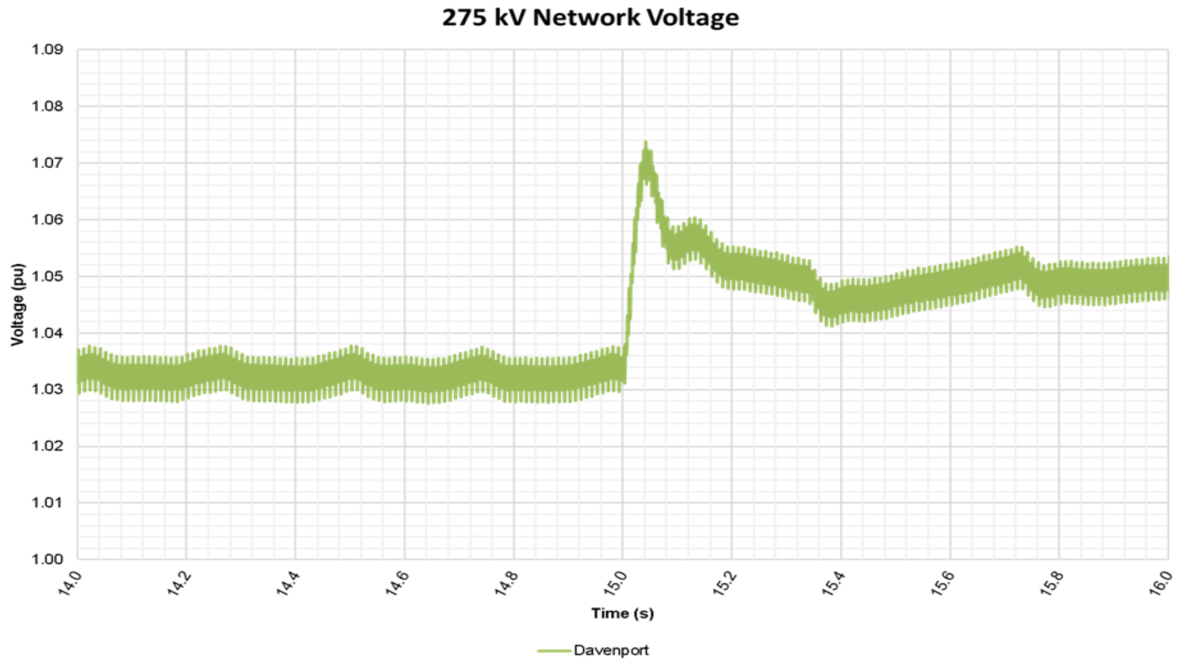
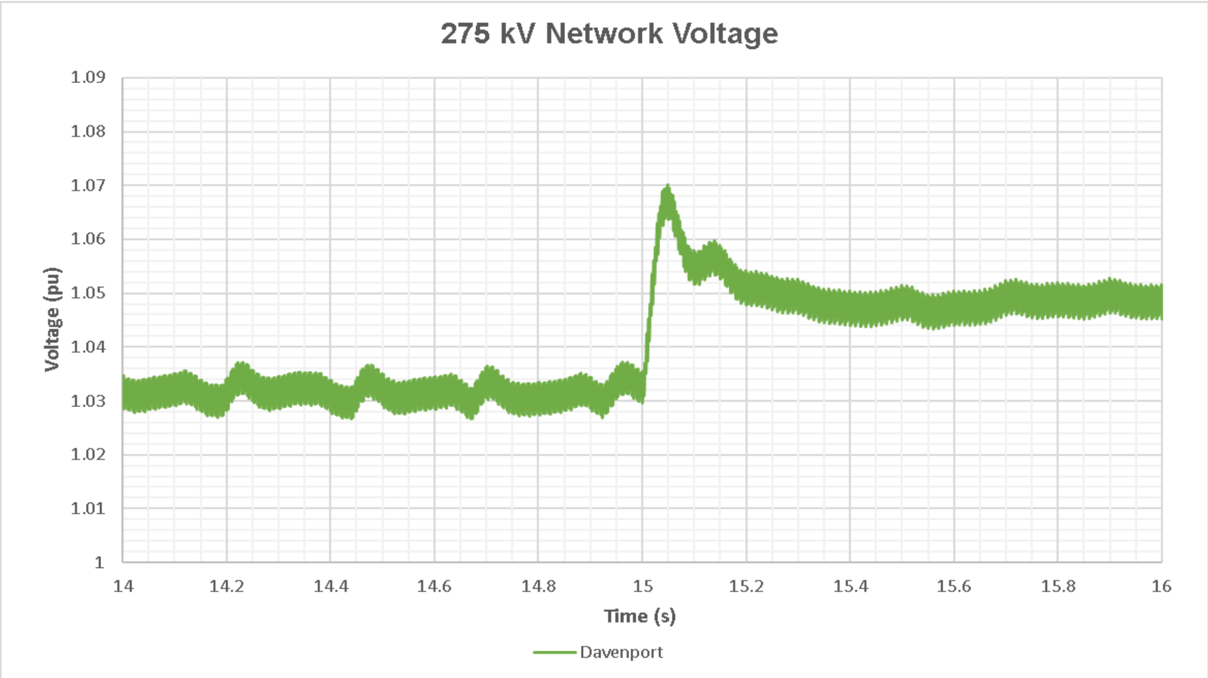


Figure 12 Davenport 275 kV bus voltage (minimum synchronous generation dispatch, with the largest synchronous generator out of service)



A.2.2.2 Asynchronous generation fault ride-through performance

The plots in this section show all SA wind farm responses following a *credible contingency event* close to *asynchronous generation*. The results show that with the minimum acceptable *synchronous generation dispatch* combinations previously identified in the SASSA, all *generating systems* in SA can ride through *credible contingency events* in accordance with their *performance standards*.

However, as identified in SASSA, when the *power system* is operating with one less *synchronous generating unit* than the minimum acceptable *synchronous generation dispatch*, either the *power system* is not operating in a *secure operating state* (refer to Figure 21), or certain wind farms will trip following a *credible contingency event* (Figure 22). In these cases the *performance standard* compliance criterion is not met.

Three phase fault at Davenport 275 kV

Figure 13 to Figure 16 demonstrated that all wind farms in SA can ride through a three phase fault at the Davenport 275 kV *busbar*, even though some of their *performance standards* do not require them to ride through a three phase fault in the SA *power system*.

Figure 13 Wind farm active power response

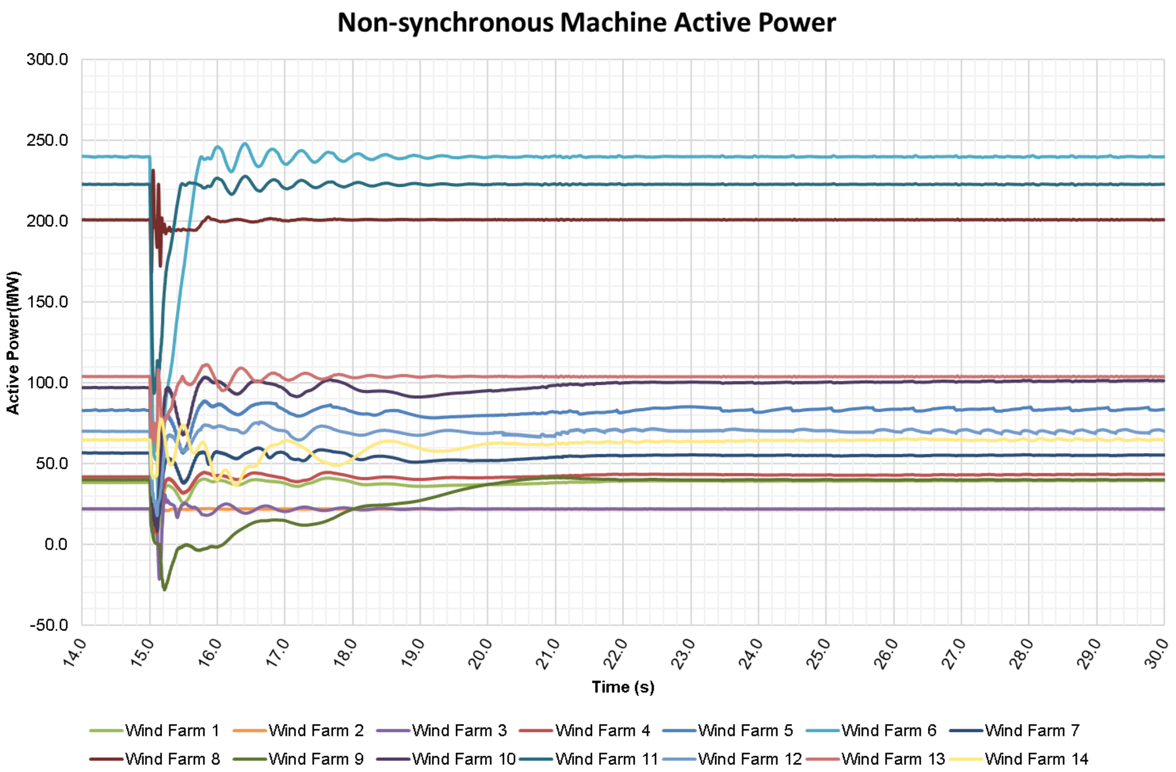


Figure 14 Key transmission voltages

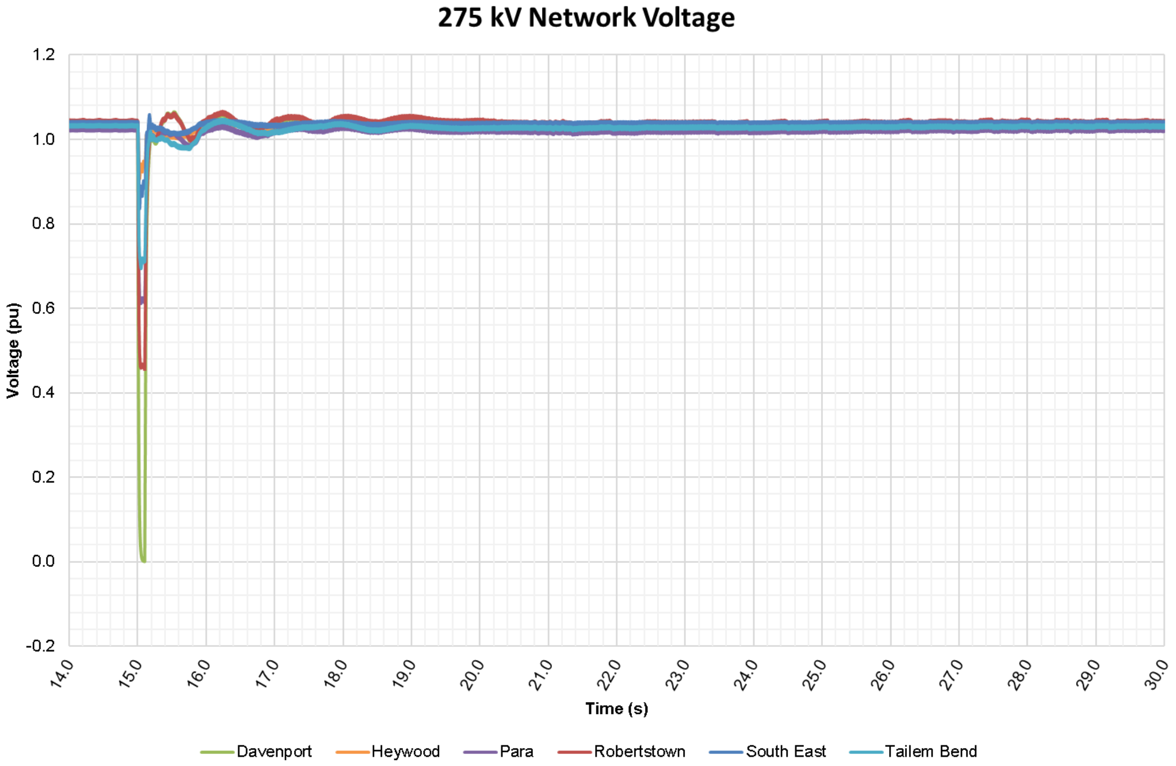


Figure 15 Heywood Interconnector active power and reactive power

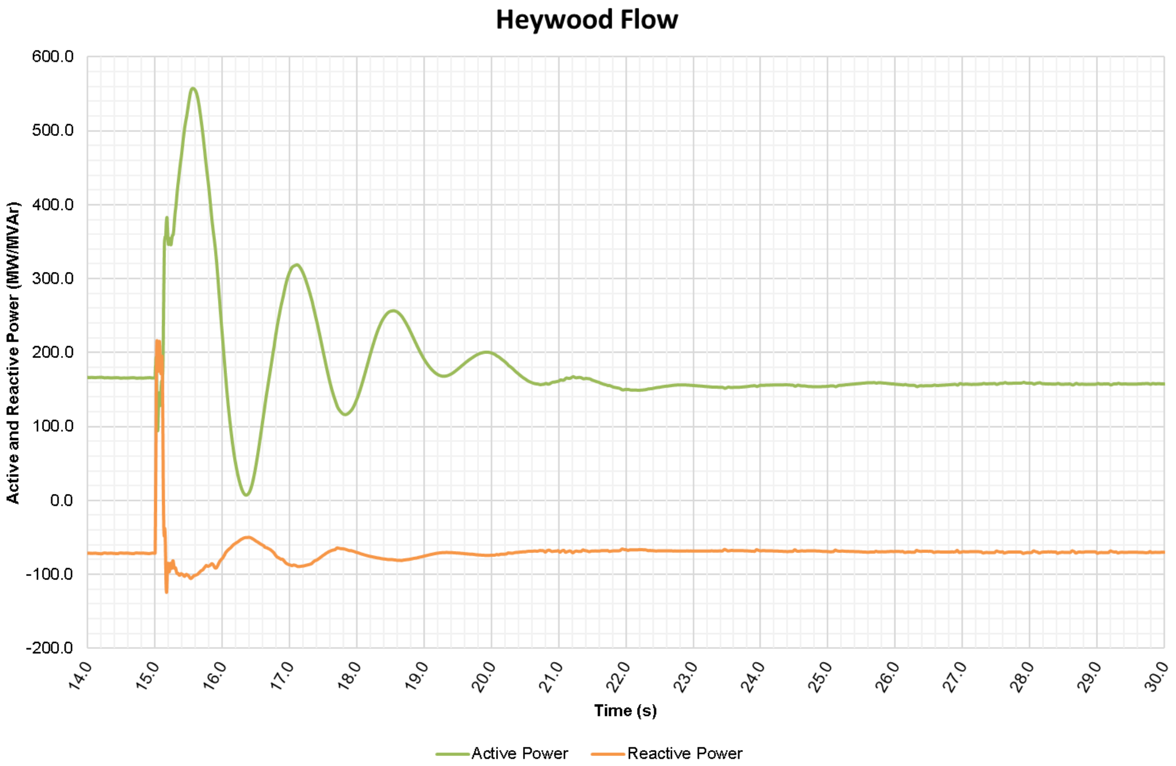
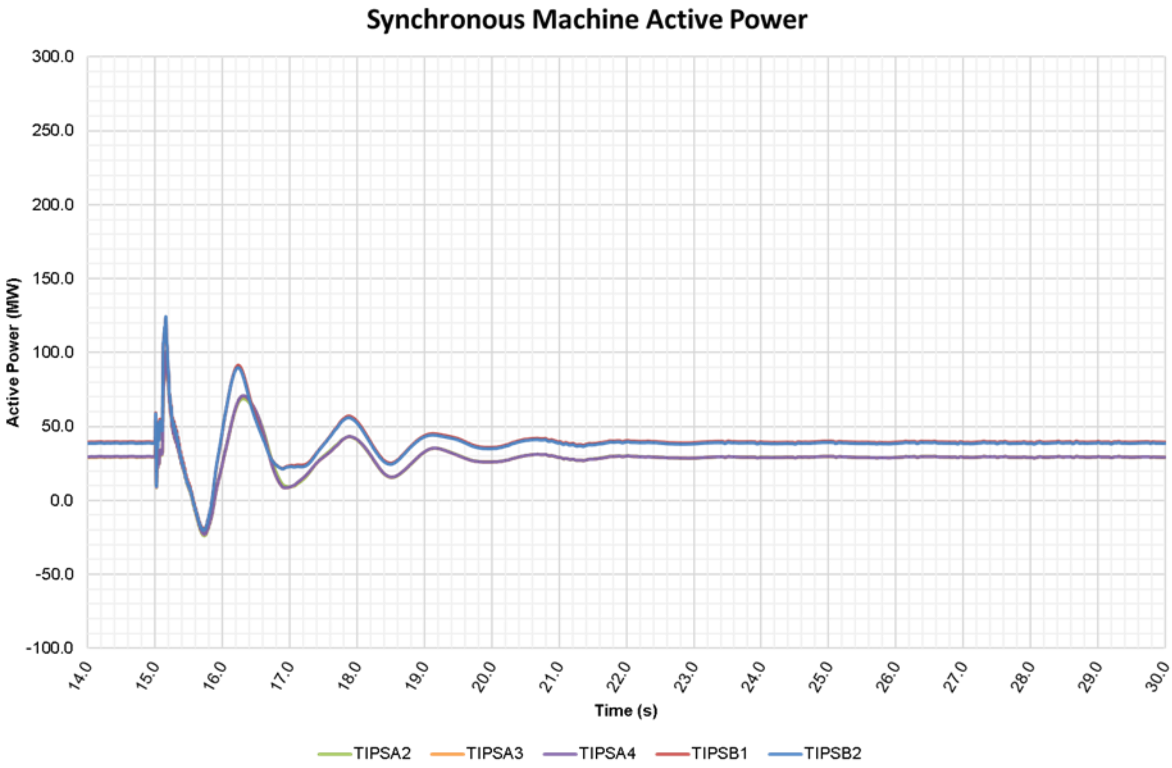


Figure 16 Synchronous generation active power



Two Phase to ground fault at Yadnarie 132 kV

Figure 17 to Figure 20 shows all wind farms can ride through a two-phase-to-ground fault at Yadnarie 132 kV *busbar*.

Figure 17 Wind farm active power

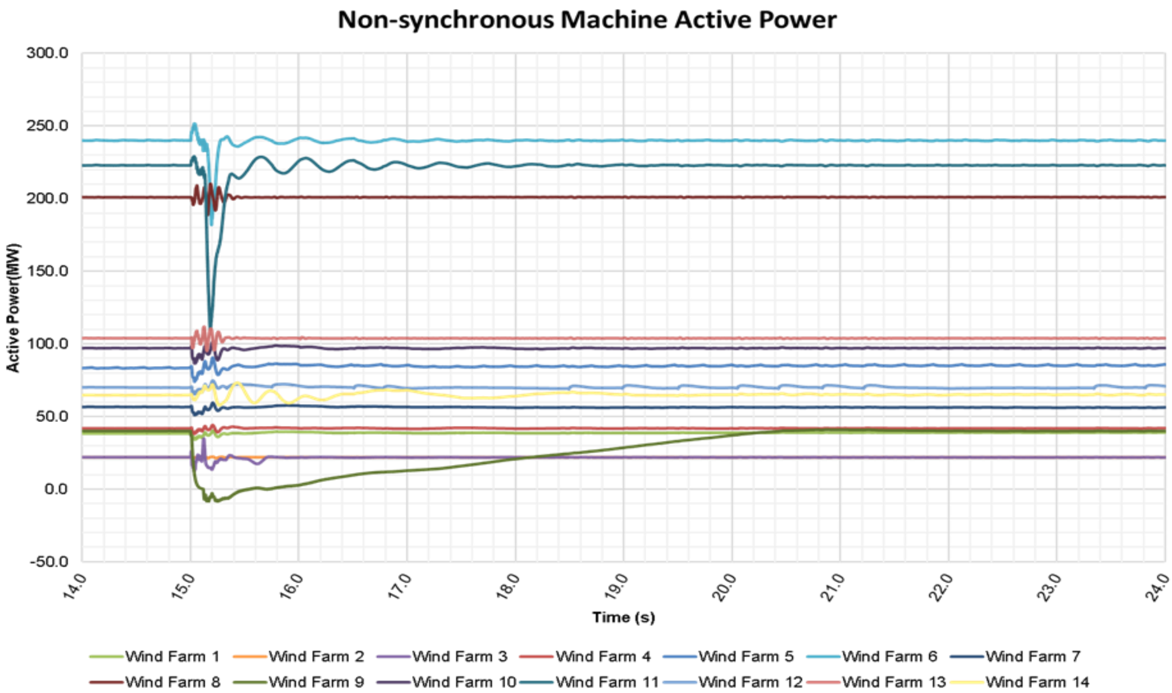


Figure 18 Key transmission voltages

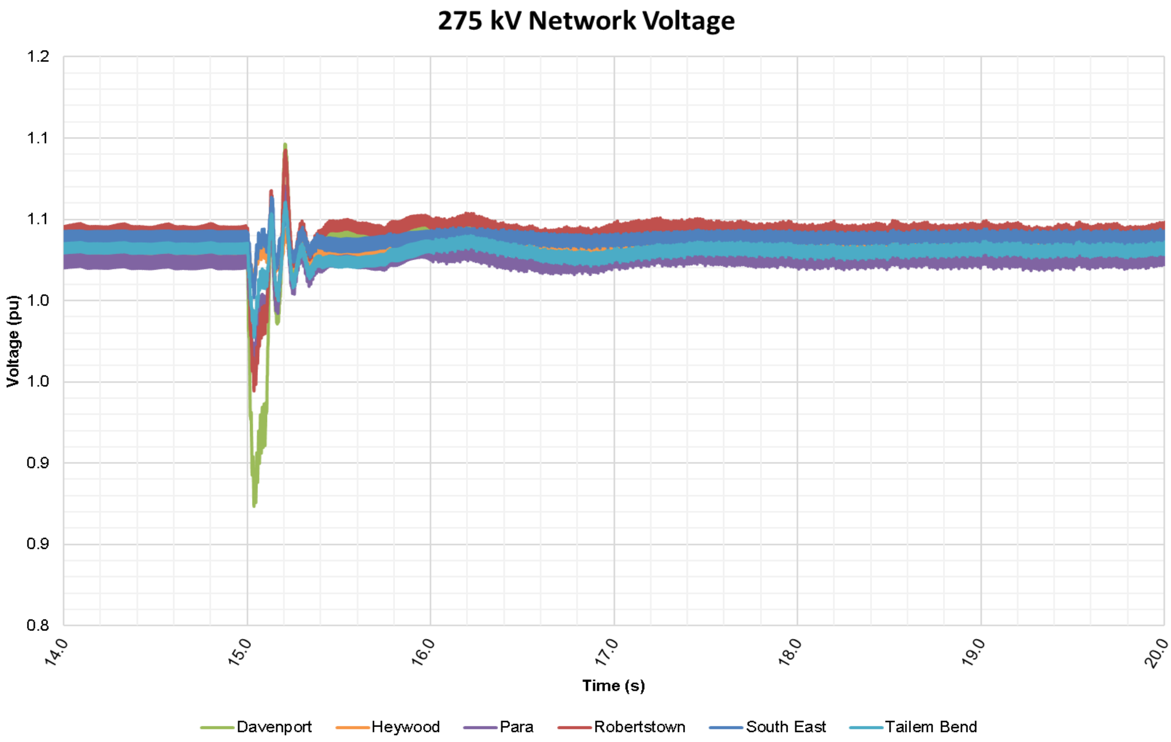


Figure 19 Heywood interconnector active power and reactive power flow

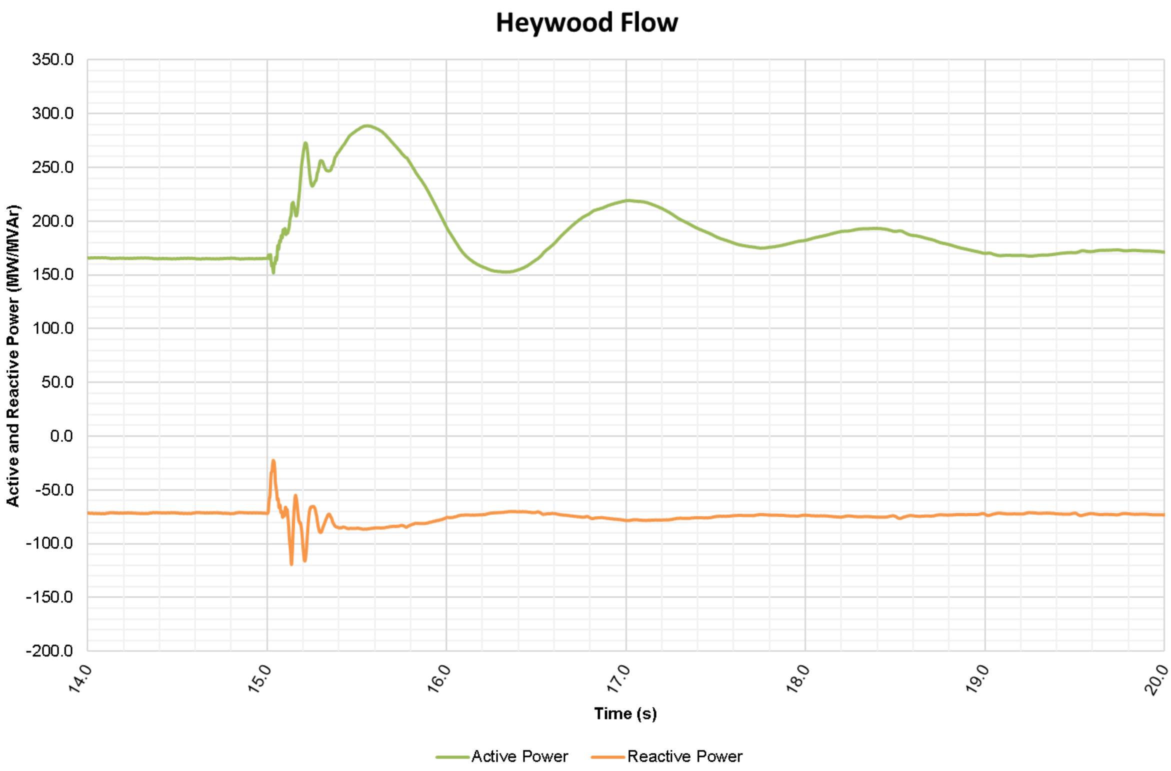
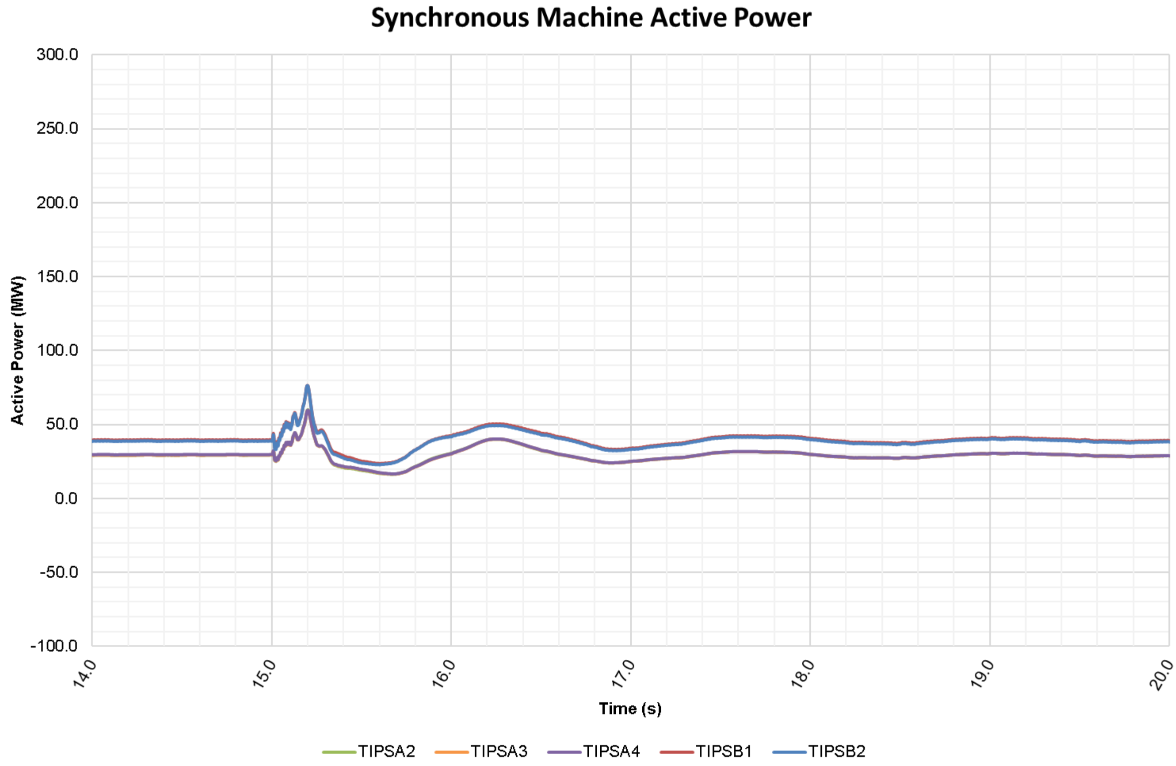


Figure 20 Synchronous generation active power



A.2.2.3 Generator responses following a credible contingency with one less synchronous generator in service

Figure 21 shows that when SA *power system* is operating with one less *synchronous generating unit* than the identified minimum combination, losing another *synchronous generating unit* due to a *credible contingency* will cause cascading generation tripping, hence the *power system* is not in a *secure operating state*. Although one such contingency might not necessarily occur near any wind farm connection point, such a contingency would cause wider impact on system *voltage*, which would affect wind farm fault ride through more than a contingency closer to the wind farm *connection point*.

Figure 21 Generator responses for a credible generation event causing other generation to trip

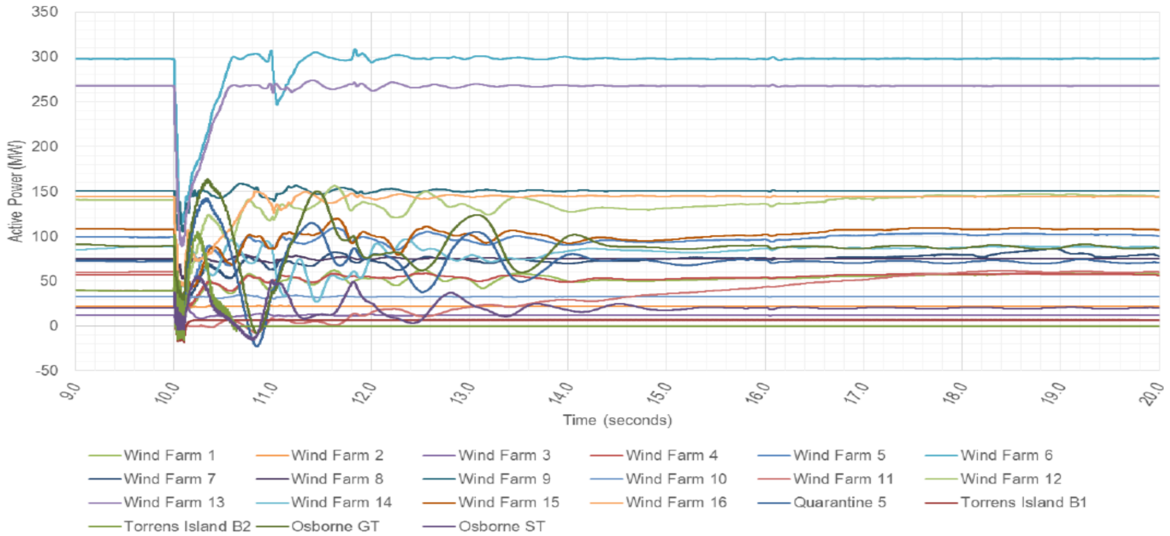
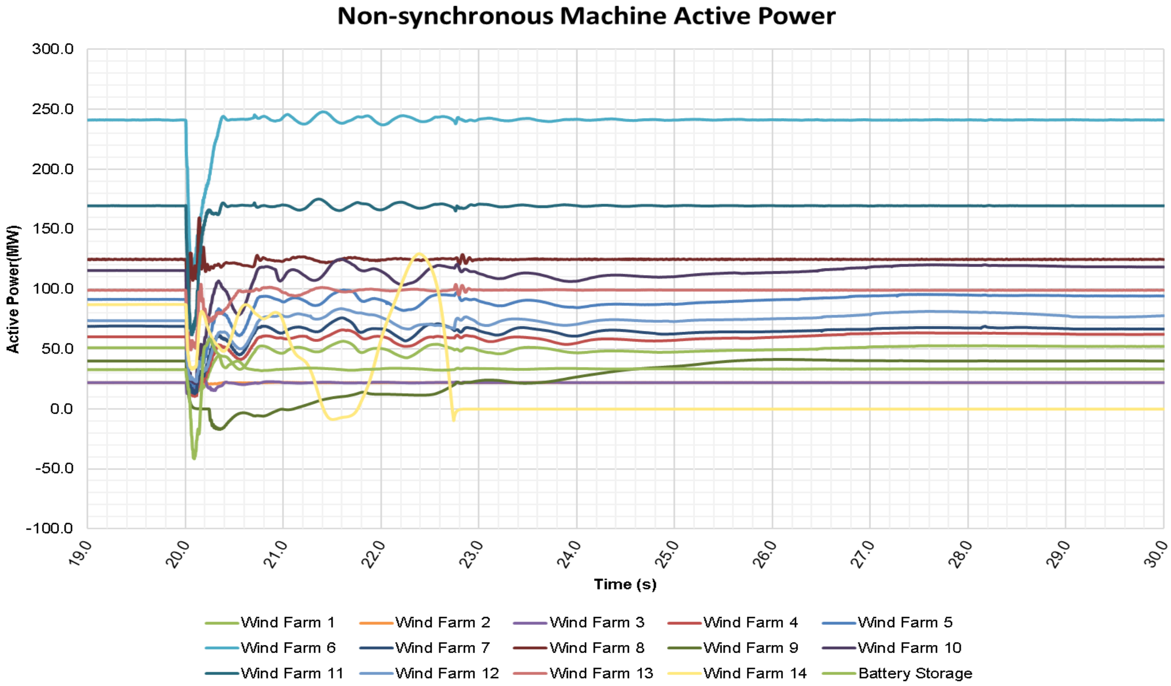


Figure 22 shows that one wind farm failed to ride through a two-phase-to-ground fault (fault applied at Yadnarie 132 kV) SA *power system* is operating with one less *synchronous generating unit* than the identified minimum Synchronous Machine combination, thus did not meet its *performance standards.*

Figure 22 Wind farm tripping following credible contingency



A.2.3 Assessment results with system islanding condition

The following sections demonstrated the *voltage* step change limit criteria can also be met under SA islanding conditions, with the minimum Synchronous Machine *dispatch* combinations.

The study results show that certain wind farms tripped on SA separation, or following the second *credible contingency event* after SA stable island was established. It is further noticed that all SA wind farms can ride through the same second *credible contingency event* if it occurs under system normal conditions rather than SA islanding conditions.

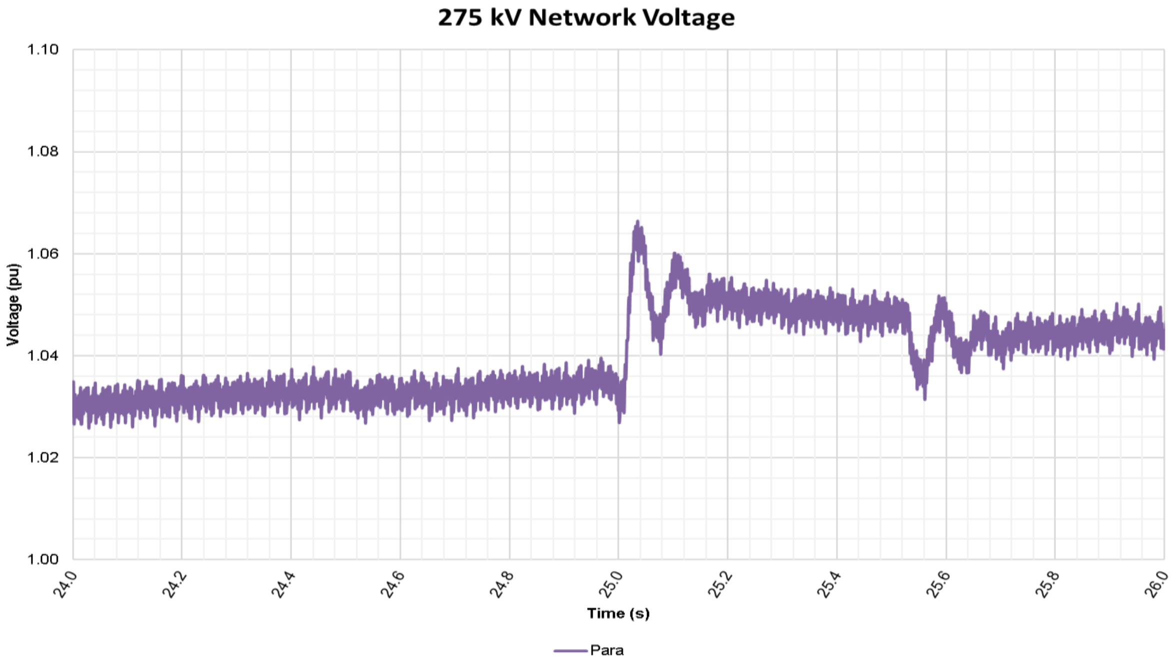
In all study results for SA islanding, the SA *power system* successfully recovered from both the separation event and the next *credible contingency event*, even though both events caused wind farm tripping. It is considered that these trips did not compromise *power system security*, and the minimum Synchronous Machine *dispatch* combination can provide sufficient system strength to ensure SA *power system* operating in *secure operating state*.

A.2.3.1 Reactive power plant switching

Para 275 kV 100 MVAr capacitor bank switching

Study results show that with the minimum acceptable *synchronous generation dispatch* scenarios previously identified in the SASSA, the capacitor bank switching at the Para 275 kV *busbar* will not cause the steady state *voltage* step change to exceed 3% (less than 2% as identified in Figure 23), when such switching occurs during an SA *islanding* condition.

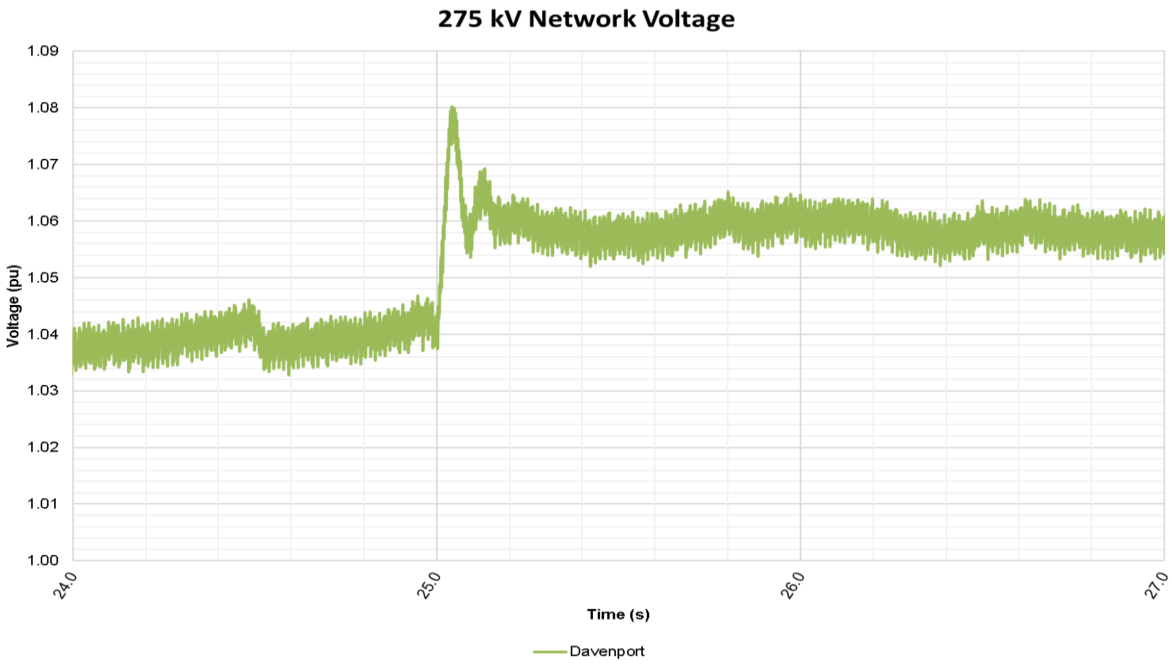
Figure 23 Para 275 kV bus voltage



Davenport 275 kV 50 MVAr reactor switching

Study results show that with the minimum acceptable *synchronous generation dispatch* scenarios previously identified in SASSA, the reactor bank switching at the Davenport 275 kV *busbar* will not cause the steady state *voltage* step change to exceed 3% (2% as identified in Figure 24), when such switching occurs during an SA *islanding* condition.

Figure 24 Davenport 275 kV Voltage



A.2.3.2 Wind farm fault ride-through

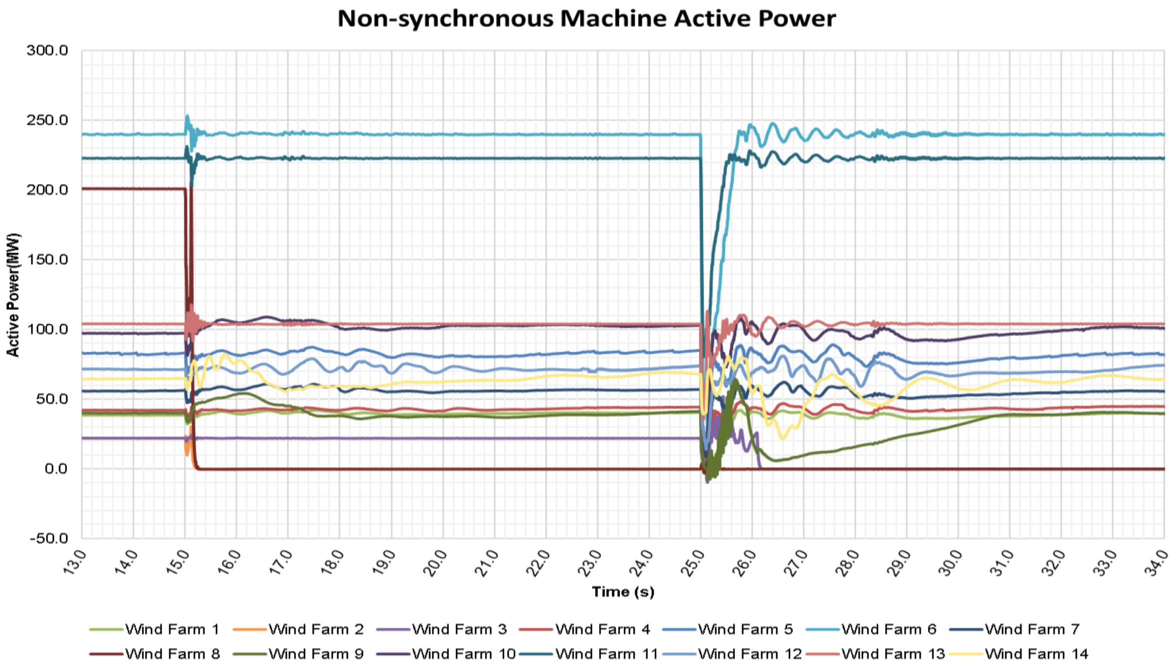
Study results indicate that most wind farms can ride through a *credible contingency event* in accordance with their *performance standards*. The performance has been assessed with the SA *power system* separated from the rest of the *NEM*, using a minimum acceptable *synchronous generation dispatch* pattern previously identified in the SASSA.

Certain wind farms tripped either at the time of separation, or following a second *credible contingency event* after the separation. These findings match the wind farm tripping reported in the South Australia Power System Operation as a Viable Island report[18]. Even with these trips, the SA *power system* still recovered, with the majority of the wind farms riding through the fault in accordance with their *performance standards*.

Three phase fault at Davenport 275 kV

Figure 25 shows two wind farms tripped following the *contingency event* that separated SA from the rest of the *NEM*, which was also observed in the studies documented in the South Australia Power System Operation as a Viable Island report. Another wind farm tripped following the three phase fault at the Davenport 275 kV *busbar*. All other wind farms rode through both separation event and the subsequent three phase fault at Davenport. The *voltages* in the SA *power system* were recovered to the range permitted by *system standards.*

Figure 25 Wind farm active power response



[18] Available at http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/SA_Operation_as_viable_Island_report_PUBLISHED.pdf

Figure 26 System-wide voltage profile

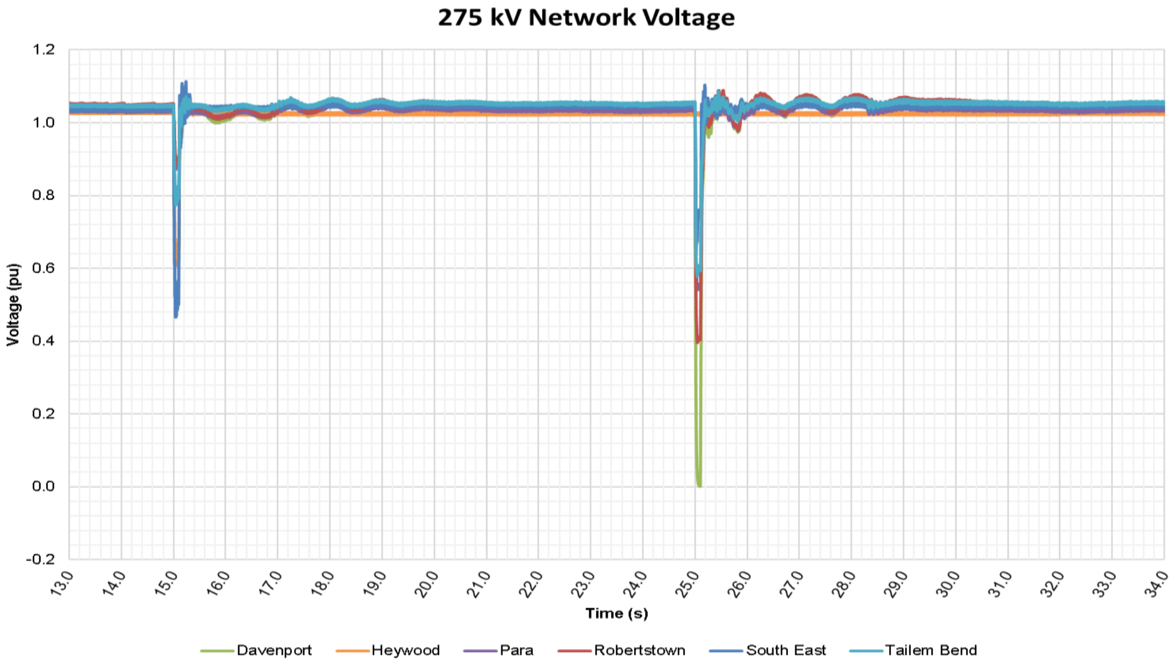
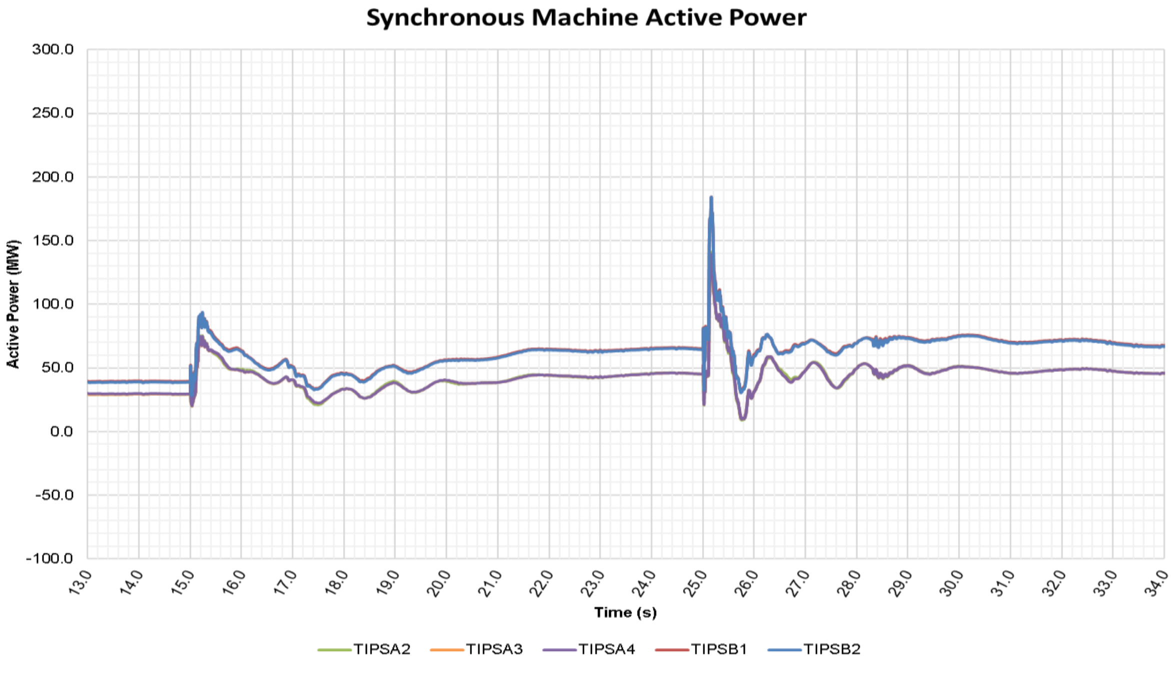


Figure 27 Synchronous generation performance



Two phase fault at Yadnarie 132 kV

Similar to the results following a three phase fault at Davenport 275 kV *busbar*, two wind farms tripped on SA separation, and another wind farm tripped following a two-phase-to-ground fault at Yadnarie 132 kV *busbar*.

Figure 28 Wind farm performance

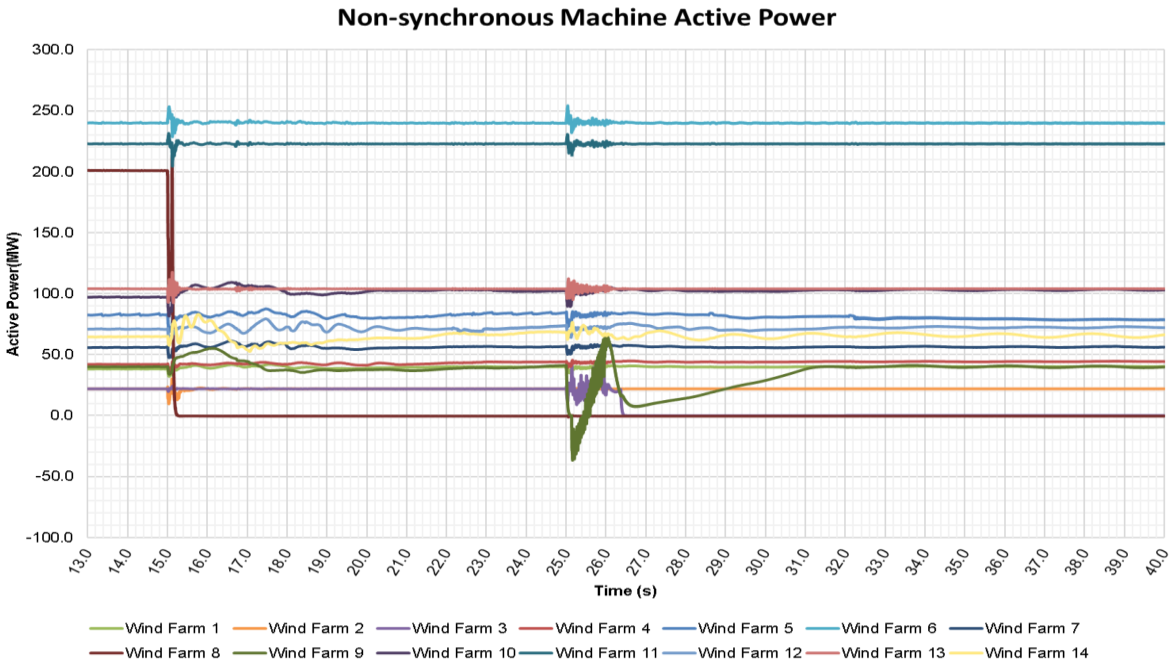


Figure 29 System-wide voltage profile

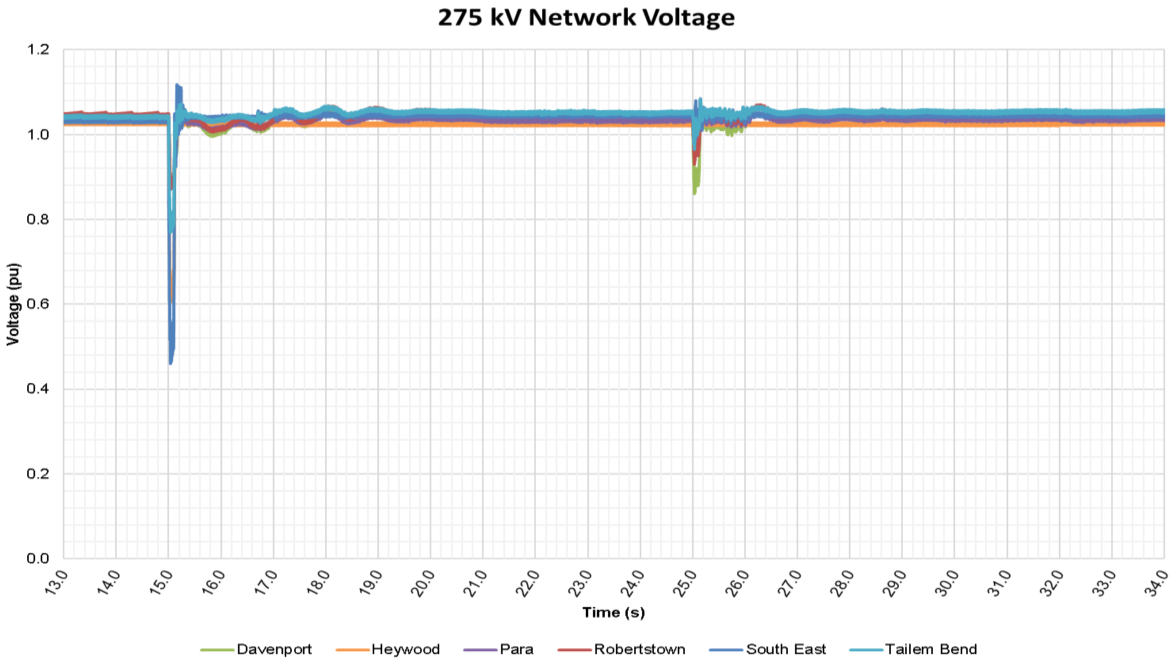
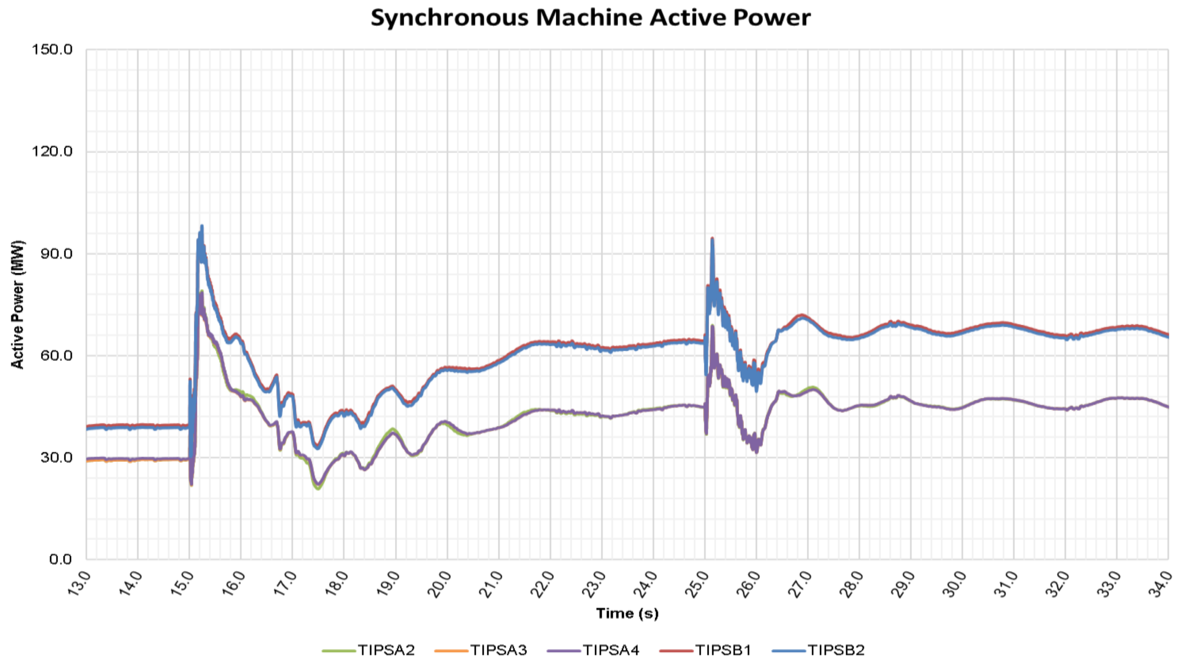


Figure 30 Synchronous generation performance



A.2.4 Conclusion

PSCAD™/EMTDC™ simulation were conducted to demonstrate that the minimum *synchronous generation dispatch* combination identified in the SASSA can meet criteria 1 and 2 in Section 9.1.1 when SA *power system* is connected to the NEM.

The results also demonstrate that at least one criterion will not be met if the SA *power system* is operating with one less *synchronous generating unit* than the minimum acceptable *synchronous generation dispatch*.

The study results suggest that the most onerous *credible contingency event* a wind farm would experience won't necessarily occur at or near its *connection point*. Study results have demonstrated that a *credible contingency event* that could cause widespread *voltage* depression might affect the wind farm more than a *credible contingency event* only affecting local *voltage*, even when the *voltage* depression at the wind farm *connection point* due to a closer *credible contingency event* is more severe.

The results also demonstrated that several wind farms tripped following the SA islanding event or the subsequent *credible contingency event* after the SA island was established. These wind farm trips did not cause the *power system* to become insecure. Further, *generating systems* which would be tripped following separation may be pre-emptively runback or tripped when the *power system* is at risk of separation, or immediately after the system separation. It is therefore proposed that when assessing criterion 2 during system islanding conditions, focus should be placed upon *system security* rather than individual *asynchronous generating systems* fault ride through.

Similarly, capacitor bank or reactor bank switching may be aborted when the *power system* is *islanded* to prevent posing additional stress on the *islanded power system*. Criterion 1 can be assessed with the *power system* as an *island*, to determine whether capacitor or reactor bank switching would cause issues such as tripping caused by high transient overvoltage or fault ride-through mode re-entry caused by high transient undervoltage. If such issues are identified in the assessment, criterion 1 is not required to be met when the *power system* is at risk of separation.

APPENDIX B. PSS®E AND PSCAD™/EMTDC™ FAULT CURRENT BENCHMARK

B.1 Purpose

Appendix B describes how AEMO compared the three phase fault current calculated in the PSS®E model and the PSCAD™/EMTDC™ model of the SA *power system,* to assess the viability of using PSS®E as an initial screening tool for identifying the *three phase fault levels* for each *fault level node* in other *regions*.

B.2 Background

AEMO proposes to benchmark the three phase fault currents calculated using PSS®E models against the fault currents calculated using PSCAD™/EMTDC™ models at specified locations. Appendix B documents the findings of one such benchmarking exercise, where the PSS®E model and the PSCAD™/EMTDC™ model of the SA *power system* were used to calculate the three phase fault current at various locations.

The purpose of the benchmarking is to gain confidence that the fault current calculated using PSS®E models is comparable to the fault current calculated using PSCAD™/EMTDC™ models. This would then enable AEMO to use PSS®E models to conduct the assessments and ascertain a proxy of the system strength in each *region* for Stage 1 assessment. If the results are sufficiently comparable, AEMO will be able to rely on those results to prioritise the Stage 2 studies using the PSCAD™/EMTDC™ models to attain more definitive calculations of the *three phase fault levels.*

B.3 Methodology

PSS®E models obtained from OPDMS have very small positive sequence reactance for wind farms and solar farms that will result in high fault current contribution from *asynchronous generation*, comparable to *synchronous generation's* fault current contribution. Such high fault current contribution from *asynchronous generation* is not realistic, so the PSS®E models must be adjusted prior to being used for any fault current calculation.

Four methodologies are proposed to adjust a PSS®E static model for *asynchronous generation*. Fault current calculations were then conducted using the adjusted PSS®E models, and the calculated three phase fault current was then compared with the three phase fault current calculated using the PSCAD™/EMTDC™ models for the same location. These are as follows:

B.3.1 Model adjustment Method 1:

Any generator representing wind turbine generators (**WTGs**), solar inverters, or battery storage systems will have its positive sequence impedance (**ZPOS**) set to 999.0 pu based on its own MVA rating. The same adjustment will apply to any FACTS device modelled with a PSS®E generator model.

B.3.2 Model adjustment Method 2:

(a) Any WTGs or solar inverters or battery storage systems will be replaced by negative *loads*, with the *load* MW and MVAr matching the negative values of the MW and MVAr *generation* being replaced.

(b) Any FACTS device modelled using a PSS®E generator model will be replaced by a fixed shunt, with the MVAr value of the fixed shunt matching with the MVAr output of the *generation* being replaced.

B.3.3 Model adjustment Method 3:

(a) Any WTGs in Type I, II and III wind farms will be replaced by negative *loads*, with the *load* MW and MVAr matching the negative value of the MW and MVAr *generation* being replaced.

(b) Any FACTS device modelled using a PSS®E generator model will be replaced by a fixed shunt, with the MVAr value of the fixed shunt matching the MVAr output of the *generation* being replaced.

(c) Any WTGs in Type IV wind farms or solar inverters or battery storage systems will have their ZPOS set to 1.0 pu based on their own MW *generation*.

B.3.4 Model adjustment Method 4:

(a) Any WTGs in Type I and II wind farms will be replaced by negative *loads*, with the *load* MW and MVAr matching the negative value of the MW and MVAr *generation* being replaced.

(b) Any FACTS device modelled using a PSS®E generator model will be replaced by a fixed shunt, with the MVAr value of the fixed shunt matching the MVAr output of the *generation* being replaced.

(c) Any WTGs in Type III and IV WTGs or solar inverters or battery storage systems will have their ZPOS set to 1.0 pu based on their own MW *generation*.

B.3.5 Comparison

The Automatic Sequencing Fault Calculation (ASCC) method in PSS®E fault calculation has been used for all fault current calculations. The "Impose flat condition" option in the ASCC calculation is not enabled.

The *generation* MW *dispatch* and *network* configuration are the same in both the PSS®E and the PSCAD™/EMTDC™ models of the SA *power system*.

The three phase fault current calculated in PSS®E using each model adjustment method are compared with the three phase fault current calculated in PSCAD™/EMTDC™.

For the SA *power system*, the comparison was conducted with three scenarios, including different *generation dispatch* and *network* configurations as follows:

- Original *generation dispatch* and *network* configuration as downloaded from OPDMS.
- Two Pelican Point *generating units* are switched off.
- Two Pelican Point *generating units* are switched off, with the 275 kV circuit from Belaile to Mokota offline.

The purpose of comparing three phase fault current results using different *generation dispatch* and *network* configurations is to validate the model adjustment methods under different *network* conditions. A valid method should yield a similar level of accuracy under different *network* conditions.

B.4 Summary and recommendation

It is recommended that Model Adjustment Method 4 is applied to adjust the PSS®E models before they are used for static fault current calculation. Model Adjustment Method 3 ignores Type I, II and III wind farm fault current contribution and is less accurate than Model Adjustment Method 4.

Model Adjustment Method 2 can be used because it is simple, it doesn't discriminate between types of technology, and assumes no fault current contribution from any *asynchronous generation*, which effectively excludes *asynchronous generation* as system strength contributors. Model Adjustment Method 2 should be used when only Synchronous Machine fault current contribution is being assessed.

Model Adjustment Method 1 is not recommended as it can produce errors in PSS®E fault current results as high as 1.1 kA (13% error compared with PSCAD™/EMTDC™ results).

The difference in the calculated three phase fault current between PSS®E and PSCAD™/EMTDC™ can be contributed by the following factors:

- The difference in Synchronous Machine fault current contribution due to the different MVAr output of Synchronous Machines in the PSS®E and the PSCAD™/EMTDC™ models. This would cause different field *voltages*, or different internal electromagnetic forces to be used in the PSS®E fault current calculation. Once the generator MVAr output in PSS®E is matched with the PSCAD™/EMTDC™ model, both models can yield very close fault current contributions from Synchronous Machines.
- The fault current contribution from Type I and II wind farms being ignored in PSS®E will not cause major errors in the fault current calculated in PSS®E, as the fault current contribution from these wind farms decays very rapidly. By the time the PSCAD™/EMTDC™ fault current is measured (100 ms after the fault inception), the fault current contribution from these wind farms is negligible.
- Type IV wind farm fault current contribution being out of phase with system fault current contribution is offset by Model Adjustment Methods 3 and 4 slightly overestimating the fault current contribution from Type IV wind farms. This will not cause major errors in the fault current calculated in PSS®E.

- Generator unsaturated subtransient reactances are used in the PSS®E fault current calculation, where a saturated subtransient reactance could result in a higher fault current contribution from Synchronous Machines. The saturation effect is modelled in PSCAD™/EMTDC™, which could contribute to a difference in the calculated fault current between PSS®E and PSCAD™/EMTDC™.

Based on these findings, the fault current calculation should be carried out in PSS®E using generator subtransient reactances, based on the following justification:

- The PSS®E ASCC method is calculating initial AC RMS fault current that can match with the PSCAD™/EMTDC™ AC RMS fault current at 20 ms after fault inception. This correlation is only true when the wind farm fault current contributions are excluded from the calculation.
- In PSCAD™/EMTDC™ models, with wind farm fault contribution, the AC RMS fault current at t = 20 ms after the fault inception is very high, and decays very fast. PSS®E models do not have the capability to capture this high and fast decaying AC fault current for all fault locations and *generation dispatch* patterns. Furthermore, most power electronic devices take longer time to respond to *power system* disturbances. For assessment, the total fault current at close to *circuit breaker* opening time (i.e. 100 ms) should be considered to assess system strength for protection operation, as well as stability assessment.
- The AC fault current contribution from Synchronous Machines will decay, and the decayed AC fault current can be calculated using generator transient reactances. However, due to different machine characteristics, the timeframe for transient reactance to take effect is not the same for all *generating units*. Thus, using transient reactances to assess *system strength requirements* could introduce errors that are subject to machine characteristics and *dispatch* patterns.
- The fault study results show that the short circuit current characteristics are different for *power systems* dominated by *synchronous generation* vs *power systems* with high *asynchronous generation*. For *power systems* with high *asynchronous generation*, such as SA, certain PSS®E model adjustments should be carried out before the PSS®E model can be used. The overall accuracy compared with the PSCAD™/EMTDC™ total fault current at 100 ms after the fault inception is quite good when the fault currents in PSS®E are calculated with the generator subtransient reactance. Given different *regions* are shifting from Synchronous Machine dominance to high *asynchronous generation*, from a planning point of view, it is beneficial to use subtransient reactance in the fault current calculation to retain the same level of accuracy as in SA.
- For *power systems* currently dominated by Synchronous Machines, both subtransient and transient reactance can be used for fault current calculations in PSS®E, as both types can be used to determine the fault current contribution from Synchronous Machines. The fault current calculation using subtransient reactances is going to produce higher fault currents as compared with using transient reactances. This could indicate higher *system strength requirements* to maintain, and also provide a margin of error by setting higher *system strength requirements*. This could increase the likelihood of triggering a more detailed assessment in Stage 2 to capture potential *fault level shortfall* due to future *generation* retirements or forced *plant outages*.

The fault current calculation should consider a range of PSS®E snapshots with different *generation* MW and MVAr output to establish a proper distribution of bus three phase fault current.

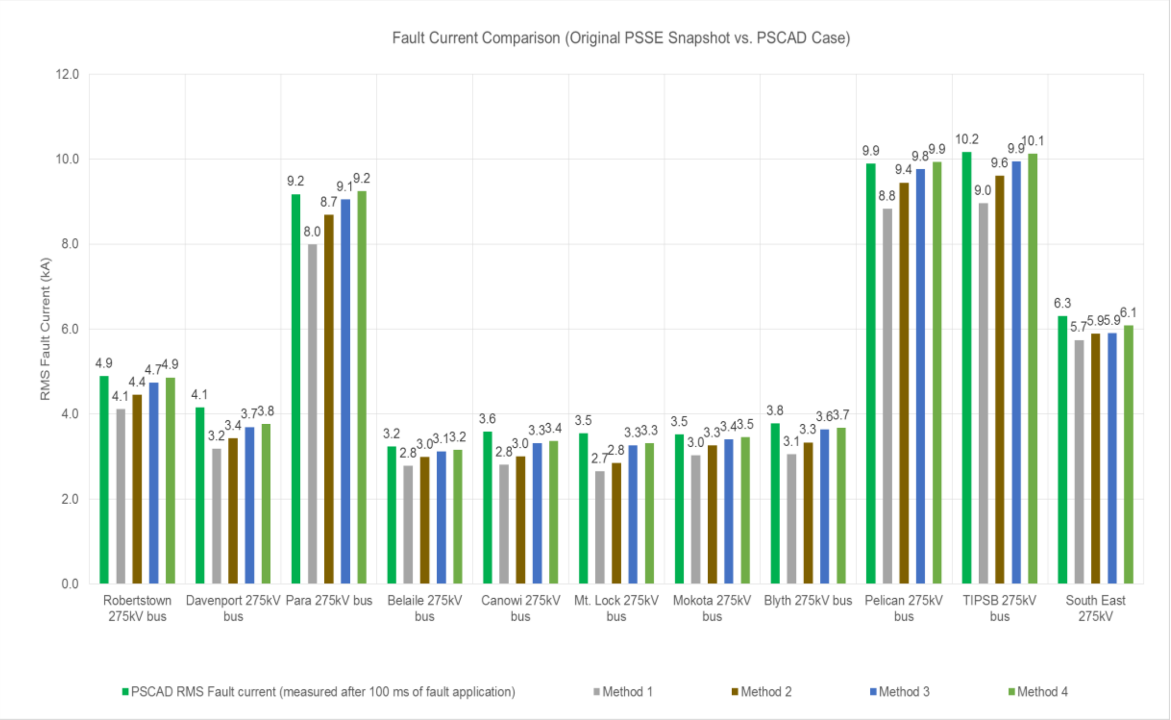
Further discussion on this is included in Appendix B.5, Appendix B.6 and Appendix B.7.

B.5 Fault current comparison in the SA power system

The following bar charts show the three phase fault current calculation comparison between PSS®E and PSCAD™/EMTDC™ under different *network* conditions, using different PSS®E model adjustment methods.

B.5.1 Original network in PSS®E and PSCAD™/EMTDC™

Figure 31 Fault level comparison – original network condition[A]



A. Generator subtransient reactances have been used to calculate fault current in PSS®E.

Figure 32 Fault level difference (PSS®E fault current – PSCAD™/EMTDC™ fault current) – original network condition

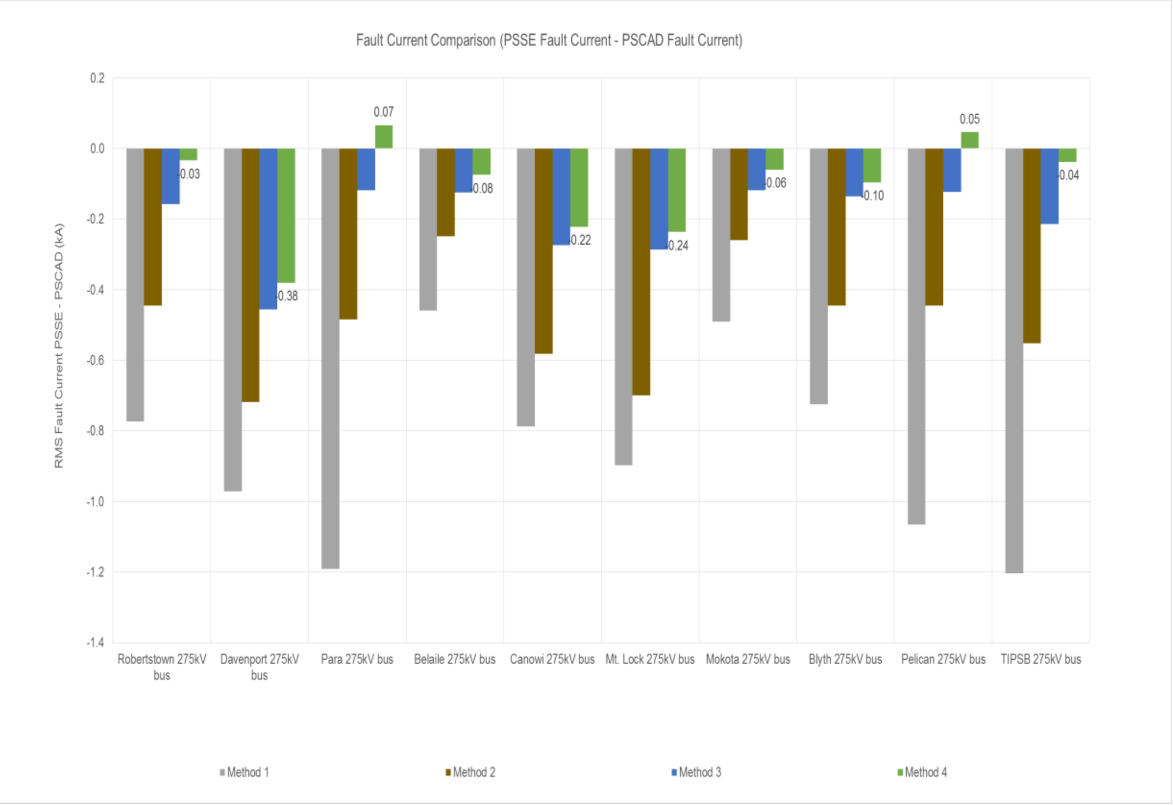


Figure 31 shows the calculated three phase fault current at various locations in PSS®E and PSCAD™/EMTDC™. The fault currents are expressed in kA. The results show that the PSS®E model following Model Adjustment Method 4 yielded the closest three phase fault current as compared with the PSCAD™/EMTDC™ model.

Figure 32 shows the difference between the PSS®E fault current results and PSCAD™/EMTDC™ (negative value means the PSCAD™/EMTDC™ fault current is higher than PSS®E). Following Model Adjustment Method 4, the largest difference is observed at Davenport, with the PSCAD™/EMTDC™ three phase fault current being 0.38 kA higher than the PSS®E fault current.

B.5.2 Two Pelican Point Generating Units Offline

Figure 33 and Figure 34 show the three phase fault current comparison between PSS®E and PSCAD™/EMTDC™, with two Pelican Point *generating units* switched off. Similar to the comparison with the original PSS®E snapshot, Model Adjustment Method 4 shows the best correlation between PSS®E and PSCAD™/EMTDC™ three phase fault current.

Figure 33 Fault level comparison – two Pelican Point generating units switched off

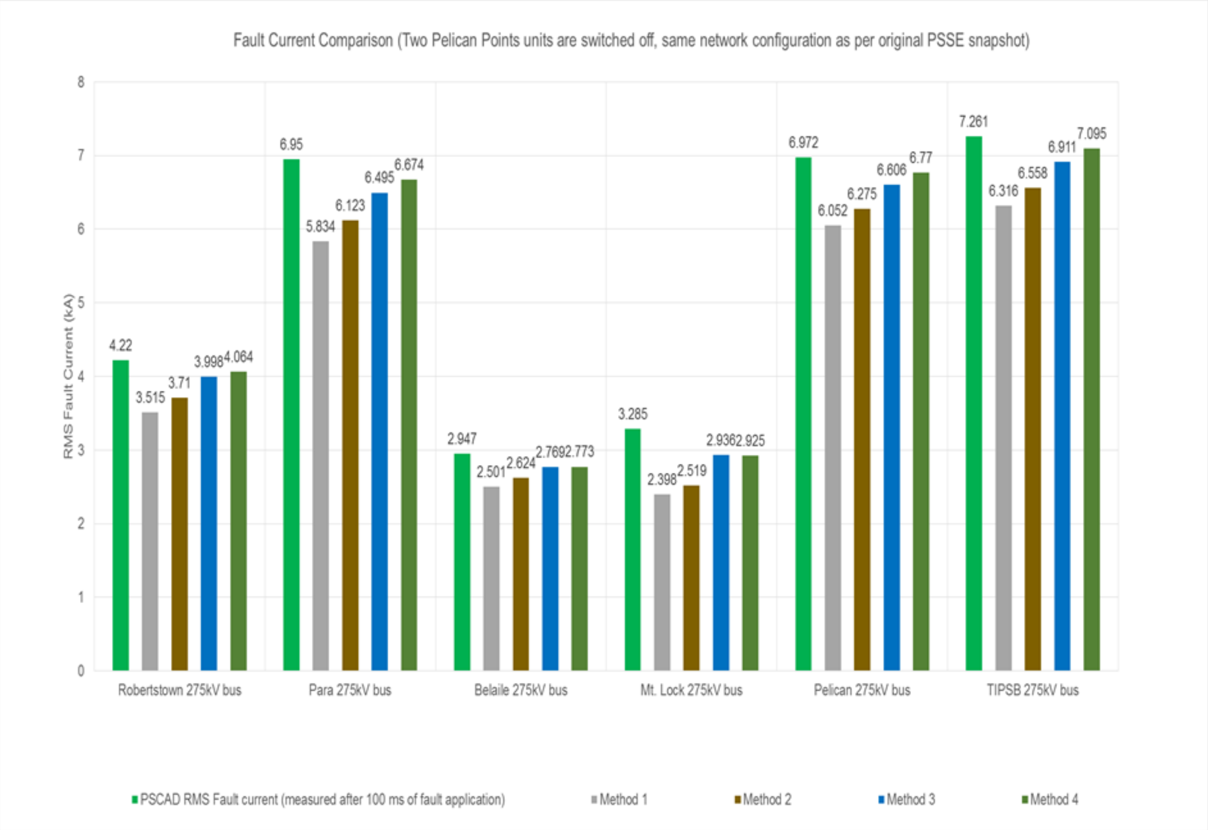
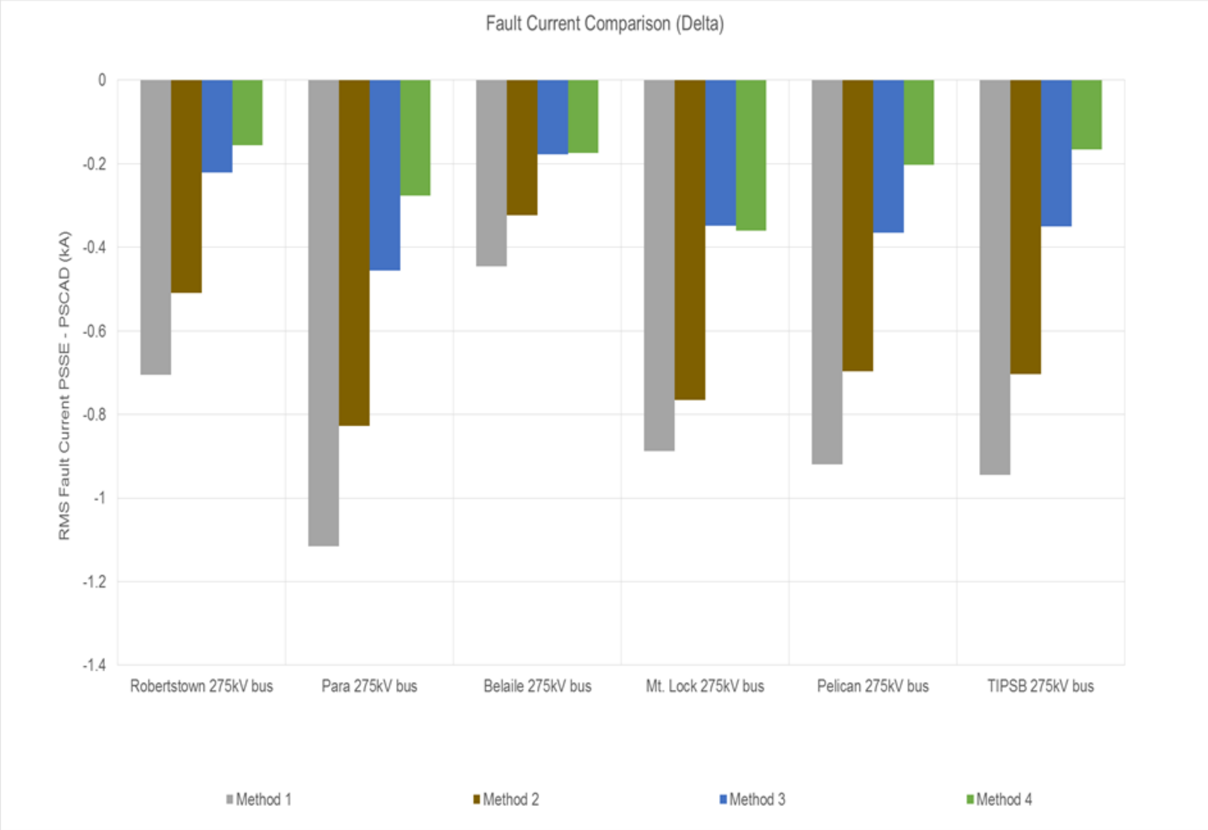


Figure 34 Fault level difference – two Pelican Point generating units switched off



Comparing Figure 34 and Figure 32, it can be seen that the three phase fault current difference between PSS®E and PSCAD™/EMTDC™ at Para, TIPSB 275, and Pelican Point slightly increased when two Pelican Point *generating units* are switched off, while the three phase fault current difference at Robertstown and Belaile remained almost the same.

This is because at Para, TIPSB, and Pelican Point, the dominating fault current contributions are from *synchronous generation*. With less *synchronous generation* online, the percentage of wind farm and *network* fault contribution will increase, which is approximated by PSS®E during fault current calculations compared with the actual fault current contribution presented in the PSCAD™/EMTDC™ model. This could lead to a slightly larger deviation from the PSCAD™/EMTDC™ fault current. Robertstown and Belaile are further away from the SA *generation centre*, thus having less *synchronous generation* online will have less impact on the fault current on these *busbars*.

B.5.3 Two Pelican Point generating units offline and 275 kV Belalie–Mokota circuit off

Figure 35 and Figure 36 show the fault current comparison between PSS®E and PSCAD™/EMTDC™, with a different *generation dispatch* and N-1 of a 275 kV *transmission* circuit. Similar to the comparison with the original PSS®E snapshot, Model Adjustment Method 4 shows the best correlation between PSS®E and PSCAD™/EMTDC™ fault current.

Figure 35 Fault level comparison – two Pelican Point generating units switched off and 275 kV Belalie–Mokota circuit off

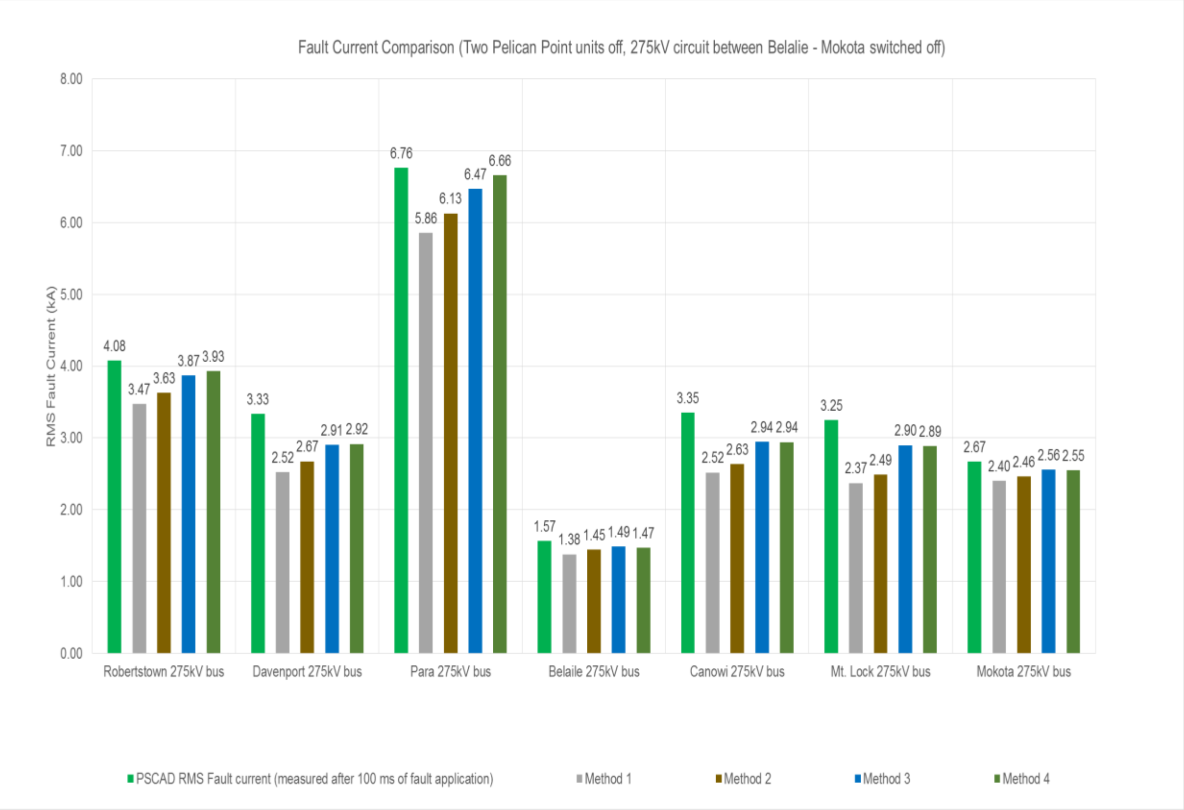
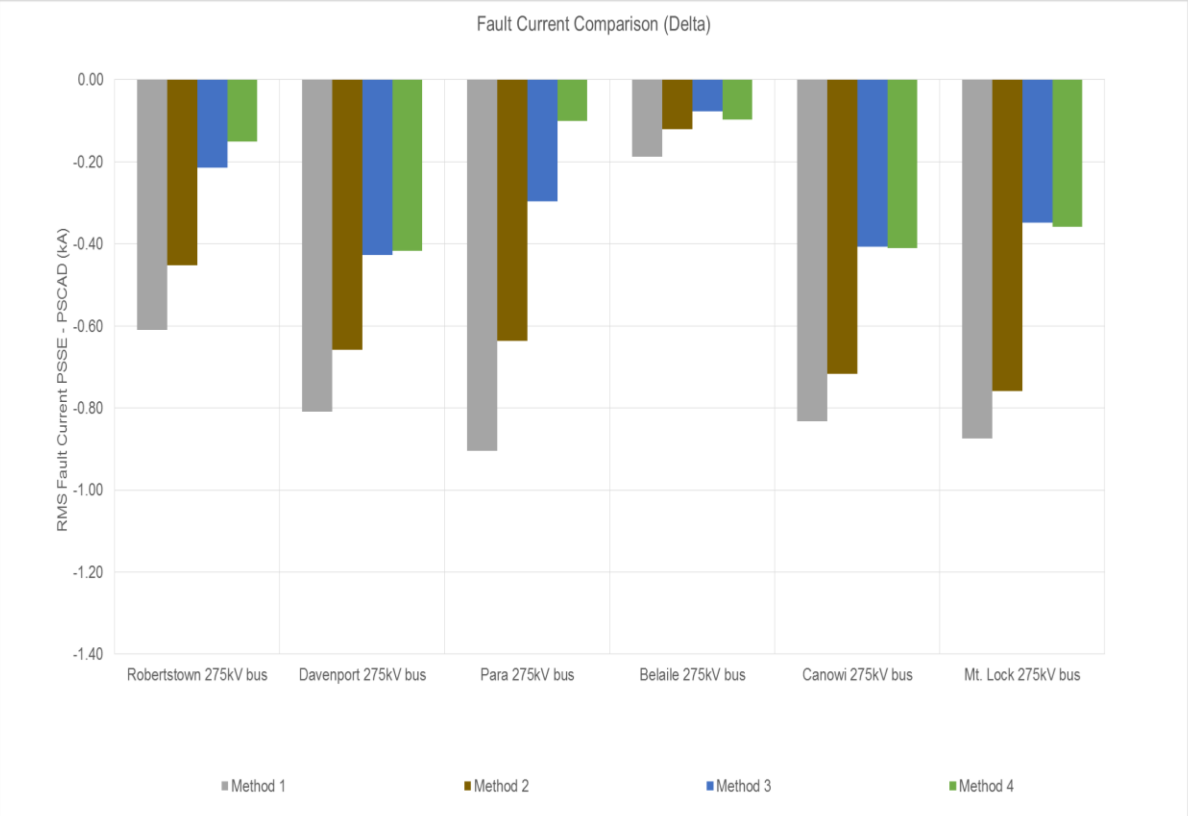


Figure 36 Fault level comparison – two Pelican Point generating units switched off, 275 kV Belalie–Mokota circuit off



B.6 Discussion

The results demonstrate that PSS®E models following Model Adjustment Method 3 and 4 can produce similar three phase fault currents as compared with the PSCAD™/EMTDC™ model.

Using Model Adjustment Method 4, fault currents calculated in PSS®E are lower than fault currents calculated in PSCAD™/EMTDC™, with two exceptions at Para and Pelican Point, where the fault current calculated in PSS®E is marginally higher than the PSS®E fault current calculated in PSCAD™/EMTDC™ (50 A and 70 A, respectively). The following sections consider factors that could contribute to the fault current differences between PSS®E and PSCAD™/EMTDC™.

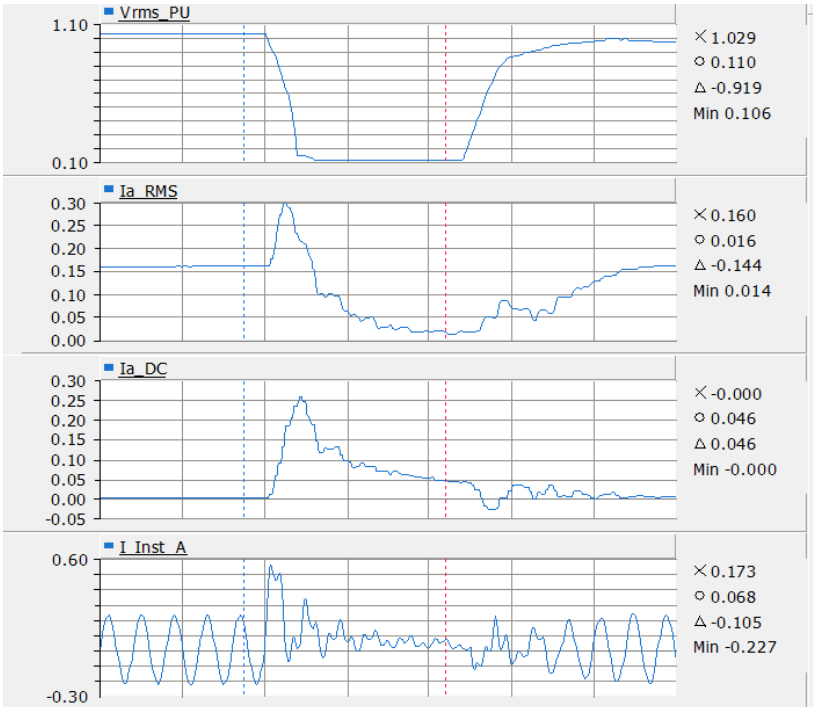
B.6.1 Type I and II wind farm fault current contribution

Type I and Type II wind farms are directly coupled with the *power system*. Like direct-online induction motors, they will inject fault current at fault inception. These fault current contributions will quickly decay due to demagnetising of the field during the fault.

In Model Adjustment Methods 3 and 4, all Type I and II wind farms are replaced with negative *loads*, which ignores the fault current contribution from these wind farms, however, this assumption will not cause major errors in the fault current comparison, as the PSCAD™/EMTDC™ fault current is measured at 100 ms after fault inception. The fault current contribution from Type I and II wind farms at this stage is already negligible.

To illustrate the fast decay of fault current injection from these wind farms, Figure 37 shows the fault current contribution from a Type I wind farm in SA calculated in PSCAD™/EMTDC™. The fault is at the *connection point*. From the plot, it can be seen the wind farm is only injecting 16A of current at 100 ms after fault inception into its 275 kV *connection point*, which is one tenth of its pre-disturbance current.

Figure 37 Fault current contribution from Type I wind farm



B.6.2 Type IV wind farm fault current contribution

The difference in three phase fault current contribution from Type IV wind farms between PSS®E and PSCAD™/EMTDC™ was also investigated. The three phase fault current at the *connection point busbar* of a Type IV wind farm, including fault current contribution from all *connecting* branches and the wind farm itself, are calculated and presented in Table 12:

Table 12 Type IV wind farm fault current contribution (fault at wind farm connection point)

	PSS®E	PSCAD™/EMTDC™
Branch 1 RMS Fault Current Contribution (kA) / fault current phase angle	1.508 / -55.70 degrees	1.463
Branch 2 RMS Fault Current Contribution (kA) / fault current phase angle	1.277 / -52.67 degrees	1.243
Wind Farm RMS Fault Current Contribution (kA) / fault current phase angle	0.774 / 2.35 degrees	0.696
Wind Farm RMS Fault Current (pu of pre-fault current at *connection point*)	1.25	1.13
Total Calculated Fault Current (kA)	3.274	3.330

It can be seen that Model Adjustment Method 4 has slightly overestimated the RMS value of the three phase fault current contribution from the Type IV wind farm, however, the total bus fault current calculated in PSS®E is smaller than the PSCAD™/EMTDC™ fault current, suggesting the wind farm fault current contribution calculated in PSS®E using Model Adjustment Method 3 is more out of phase with the branch fault current contribution, compared with the PSCAD™/EMTDC™ fault current results.

Further investigation was carried out to compare wind farm fault current contribution, following a remote three phase fault away from the wind farm *connection point*. The total bus fault current at the remote bus and the wind farm fault current contributions are calculated in PSS®E and PSCAD™/EMTDC™ and presented in Table 13:

Table 13 Type IV wind farm fault current contribution (fault at busbar away from the wind farm)

	PSS®E	PSCAD™/EMTDC™
Total Bus Fault Current (kA)	8.635	8.92
Wind Farm Fault Current Contribution (kA)	0.677	0.688

The wind farm fault current contribution calculated in PSS®E and PSCAD™/EMTDC™ following a remote fault are also quite close.

B.6.3 Synchronous generation fault current contribution

The three phase fault current contribution from *synchronous generation* is compared between PSS®E and PSCAD™/EMTDC™. The comparison is done at both machine terminal and the *high voltage connection point*, for a single machine open-circuit model (with and without its unit *transformer*), as well as with the *synchronous generation connected* to the *NEM* model.

The Synchronous Machine under consideration has the following parameters:

- X”d = 0.216 pu
- Vterminal = 16 kV
- MVA base = 250 MVA
- Xd = 1.94 pu

B.6.3.1 Synchronous machine fault current contribution at terminal (Single machine open circuit; without unit transformer)

Figure 38 shows the initial fault current contribution (100 ms after fault inception) from the *synchronous generation* at its terminal *busbar*.

Figure 38 Synchronous Machine initial fault current contribution (LV terminal)

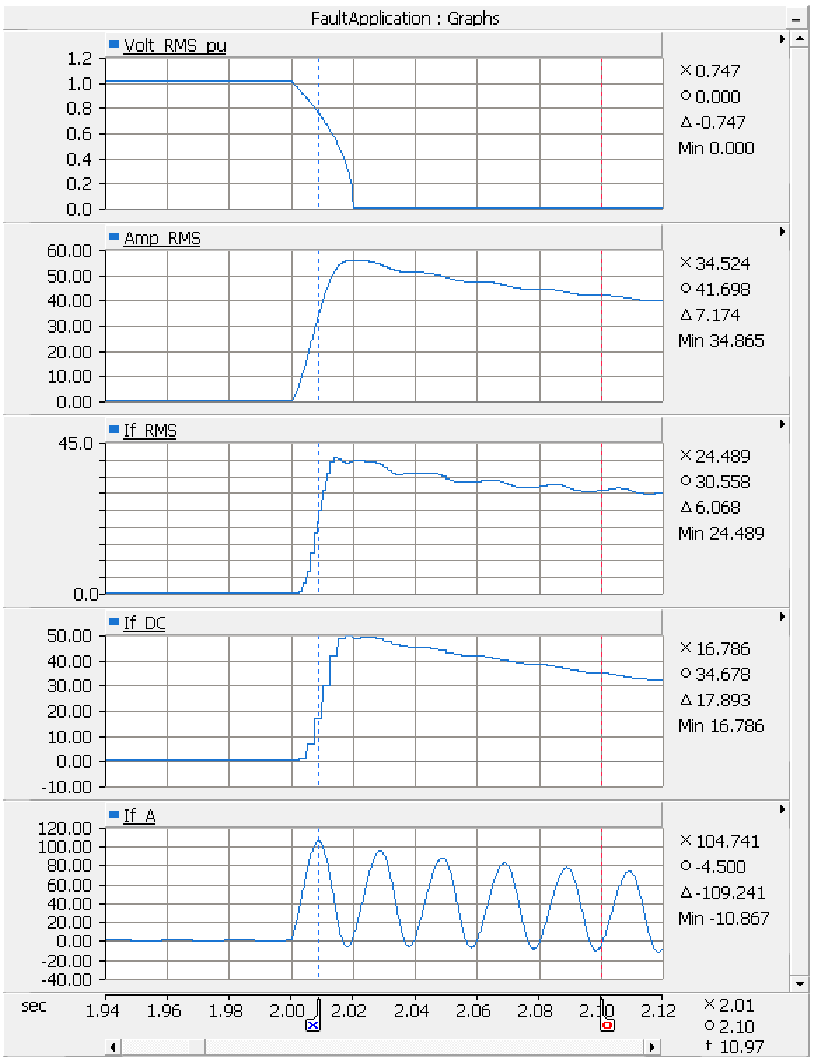


Table 14 shows the comparison of *synchronous generation* fault current contribution at its terminal, between PSS®E, PSCAD™/EMTDC™ and theoretical calculation. The comparison shows good correlation of the RMS fault current between PSS®E and PSCAD™/EMTDC™, as well as with the theoretical calculation.

In terms of the peak current, PSS®E used IEC 60909 approximation to calculate the peak current, which is slightly higher than the PSCAD™/EMTDC™ peak current due to the generator stator resistance being ignored in the PSS®E calculation. The theoretical calculation shows quite a large error (14 kA), as compared with the PSCAD™/EMTDC™ peak fault current. Closer examination shows that the theoretical calculation is calculating the peak value of the 'Top envelope' as per Figure 39, which is higher than the actual peak current of the *synchronous generation*.

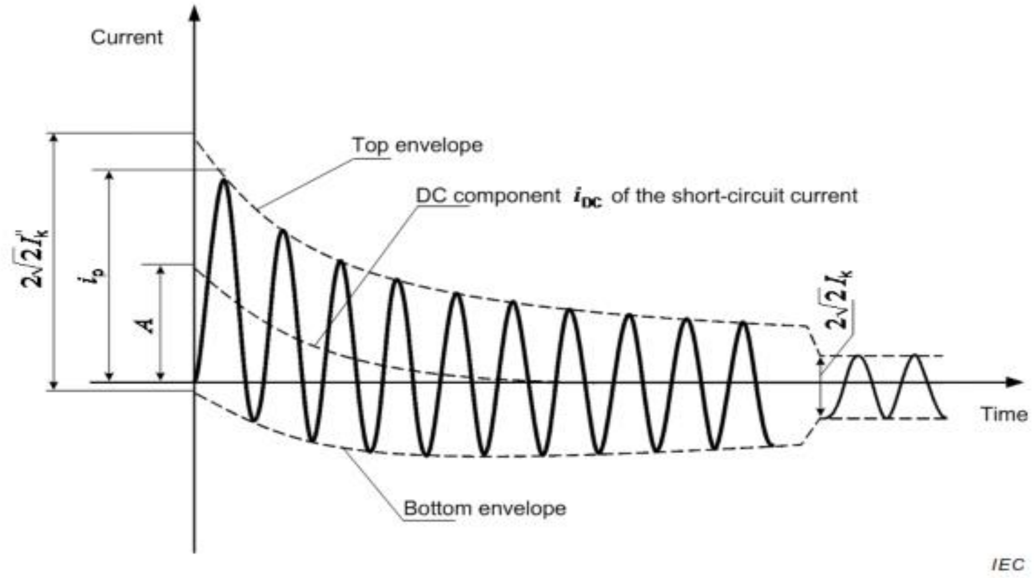
The peak current is of no interest in the assessment.

Table 14 Synchronous Machine initial fault current comparison (LV terminal)

	PSS®E	PSCAD™/EMTDC™	Theoretical calculation
RMS fault current (kA)	41.880	41.698	41.764
Peak Fault Current (kA)	110.371[19]	104.741	118.127

[19] As ASCC can't calculate the peak current, this value is calculated using IEC 60909 function in PSS®E, assuming a C factor of 1.0. This peak current is calculated using method C as per IEC 60909.

Figure 39 Synchronous Machine fault current characteristics (IEC 60909)



B.6.3.2 Synchronous generation fault current contribution at terminal (Single machine open circuit; with unit transformer)

Figure 40 shows the initial fault current contribution (100 ms after fault inception) from the *synchronous generation* at the HV side of its unit *transformer*.

Figure 40 Synchronous Generation initial fault current contribution (transformer HV side)

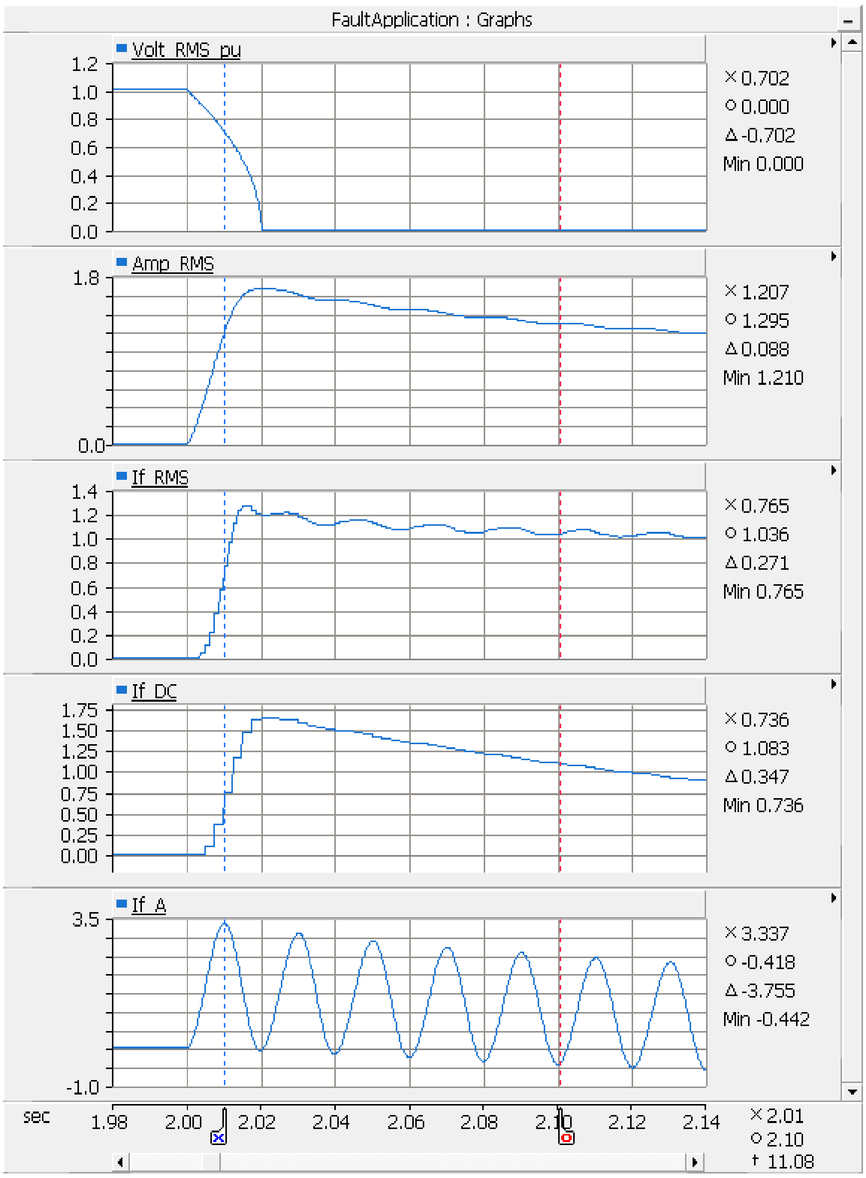


Table 15 shows the comparison of *synchronous generation* fault current contribution at its *transformer* HV terminal between PSS®E and PSCAD™/EMTDC™. The comparison shows good correlation of the RMS fault currents between PSS®E and PSCAD™/EMTDC™.

Table 15 Synchronous Generation initial fault current comparison (transformer HV side)

	PSS®E	PSCAD™/EMTDC™
RMS fault current (kA)	1.290	1.295
Peak Fault Current (kA)	3.467[20]	3.337

B.6.3.3 Synchronous generation fault current contribution at terminal (Connected to NEM, fault at connection point)

Table 16 shows a comparison of *synchronous generation* fault current contribution at the *transformer* HV side following a three phase fault at the *generating unit's connection point*, when it is *connected* to the *NEM* and *generating*. The results show the *synchronous generation* three phase fault current contribution

[20] As ASCC can't calculate the peak current, this value is calculated using IEC 60909 function in PSS®E, assuming a C factor of 1.0. This peak current is calculated using method C as per IEC 60909.

calculated in PSCAD™/EMTDC™ is higher than the fault current contribution calculated in PSS®E, which is likely the main cause of the difference between the total bus fault current calculated in PSS®E and PSCAD™/EMTDC™.

Table 16 Synchronous Machine initial fault current comparison (transformer HV side, fault at connection point)

	PSS®E	PSCAD™/EMTDC™
Synchronous Generator 1 RMS Fault Current (kA)	1.197	1.308
Synchronous Generator 2 RMS Fault Current (kA)	1.206	1.355
Synchronous Generator 3 RMS Fault Current (kA)	1.192	1.319
Total Bus fault current (kA)	9.47	9.75

Further investigation shows that the generator MVAr output in the PSS®E model and the PSCAD™/EMTDC™ model are different, with the generator absorbing 29.5 MVAr in the PSS®E model and providing 38.52 MVAr in the PSCAD™/EMTDC™ model. The difference in the MVAr output will result in different generator field *voltage*, or the internal electromagnetic force calculated in PSS®E for fault current calculation. It is noted once the generator MVAr output in the PSS®E model is matched with the MVAr output in the PSCAD™/EMTDC™ model, the RMS three phase fault current contribution from *synchronous generating unit* 1 calculated in PSS®E is increased to 1.32 kA (previously 1.197 kA), which is very close to the three phase fault current contribution (1.308 kA) calculated in PSCAD™/EMTDC™.

B.6.3.4 Synchronous generation fault current contribution at terminal (Connected to NEM, remote fault)

Table 17 shows the comparison of the *synchronous generation* three phase fault current contribution at the *transformer* HV side, following a three phase fault far away from the *generating unit's connection point*.

Table 17 Synchronous Generation initial fault current comparison (transformer HV side, remote fault)

	PSS®E	PSCAD™/EMTDC™
Synchronous Generator 1 RMS Fault Current (kA)	0.382	0.430
Synchronous Generator 2 RMS Fault Current (kA)	0.388	0.404
Synchronous Generator 3 RMS Fault Current (kA)	0.396	0.389
Total Bus fault current (kA)	3.667	4.07

Table 17 shows the fault current contribution from *synchronous generation* following a remote fault is similar in PSS®E and PSCAD™/EMTDC™. As the faulted *busbar* is further away from the *generating unit connection point*, the three phase fault current contribution from *synchronous generation* has a smaller impact on the total three phase bus fault current at the faulted *busbar*. The difference between the calculated total bus fault current in PSS®E and PSCAD™/EMTDC™ is likely to be caused by *network* characteristics (causing the fault current contribution to be out of phase) and differences in the wind farm fault current contribution.

B.7 Use of synchronous generator subtransient reactance (X"d) and transient reactance (X'd)

All previous fault level calculations in PSS®E have been using the unsaturated subtransient reactance for *synchronous generation*. The calculated bus three phase fault current is quite close to the bus three phase fault current calculated using PSCAD™/EMTDC™.

For sensitivity analysis, the unsaturated transient reactance of *synchronous generation* has been used in the PSS®E model, and the same fault current calculation was repeated. The calculated three phase fault current was plotted with the three phase fault current calculated using the subtransient reactance in PSS®E, as well as the three phase fault current calculated in PSCAD™/EMTDC™, presented in Figure 41.

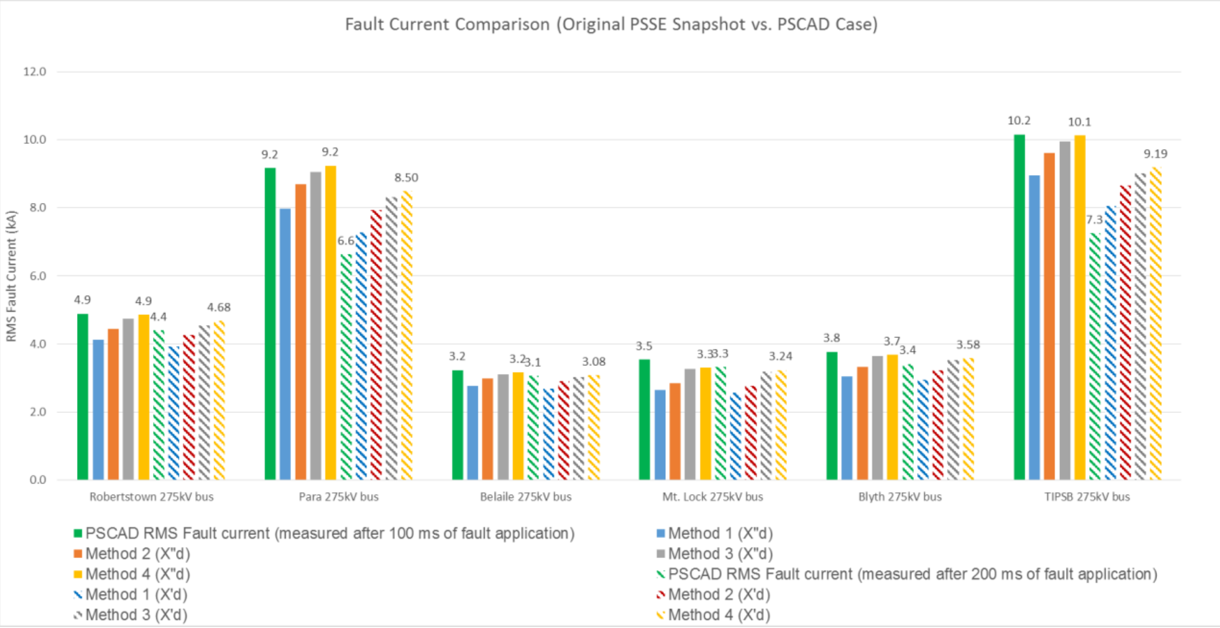
In Figure 41, the first green bar is the bus three phase fault current calculated in PSCAD™/EMTDC™ at 100 ms after fault inception, and the next four bars are the bus fault current calculated in PSS®E with the generator subtransient reactance, using different model adjustment methods.

Following the first five bars, the green bar with dashed line is the bus three phase fault current calculated in PSCAD™/EMTDC™ at 200 ms after fault inception. The last four bars are the bus fault current calculated in PSS®E with the generator transient reactance, using different model adjustment methods.

The PSCAD™/EMTDC™ fault current measured at 200 ms after fault inception is compared with the fault current calculated in PSS®E using generator transient reactances to identify whether the PSS®E fault current calculated using generator transient reactance could be used to evaluate the three phase fault currents at 200 ms after fault inception.

The fault current measured at 100 ms after fault inception should be used for stability analysis, as it represents the fault current prior to the *circuit breaker* opening as Table S5.1a.2 in NER (120 ms being the primary protection clearance time for 275 kV system in SA). This is the fault current used to benchmark fault current calculated in PSS®E for assessment.

Figure 41 Comparison of bus fault current using X"d and X'd



From Figure 41, it can be seen that when compared with the PSCAD™/EMTDC™ fault current measured at 100 ms after fault inception, the three phase fault current calculated in PSS®E using subtransient reactances have smaller errors than the three phase fault current calculated using transient reactances. This indicates that when using the generator subtransient reactances, the three phase fault current calculated in PSS®E for the SA *power system* can reflect the actual three phase fault current calculated in PSCAD™/EMTDC™ after 100 ms of fault inception, and can be used to perform the assessment.

APPENDIX C. SYSTEM STRENGTH AND CORRECT OPERATION OF PROTECTION SYSTEM

This appendix investigates the impact of system strength on the operation of *power system* distance *protection systems*. The SA *power system* has been presented as a demonstration of this.

The case study demonstrates the importance of assessing the operation of distance *protection systems* when determining the minimum acceptable *synchronous generation dispatch* scenario patterns. The minimum acceptable *synchronous generation dispatch* scenarios pattern should allow correct operation of the *protection system*.

Operation of distance protection relay was investigated in these studies, as it is the most common form of *transmission line* protection.

C.1 Mechanism for protection system maloperation under low system strength condition

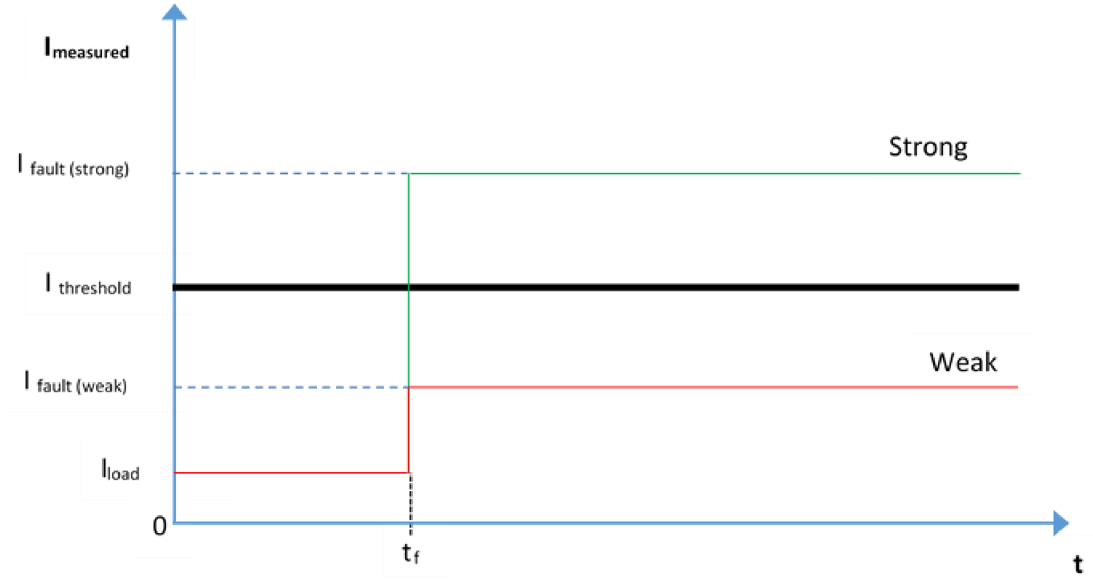
Protection maloperation can be caused by several mechanisms that are usually identified under weak grid conditions, described as follows:

C.1.1 Blocking of the relay operation due to low fault current levels

To maintain a certain reliability of the decisions made by a distance relay, the measured currents need to be above a given threshold value (a setting of the relay). If the measured current is lower than this threshold, the relay will block trip signals from distance elements. The current threshold is implemented to eliminate undesirable operation of the relay due to measurement errors and numerical errors in digital implementation of relay functions.

Under weak grid conditions, the fault current may drop to a value lower than this threshold current (see Figure 42). Hence, the relay operation will be blocked even though the fault is on the line protected by the relay. This not the expected operation of the relay and can be treated as a maloperation.

Figure 42 Measured current in network with strong and low system strength (fault applied at t_f)



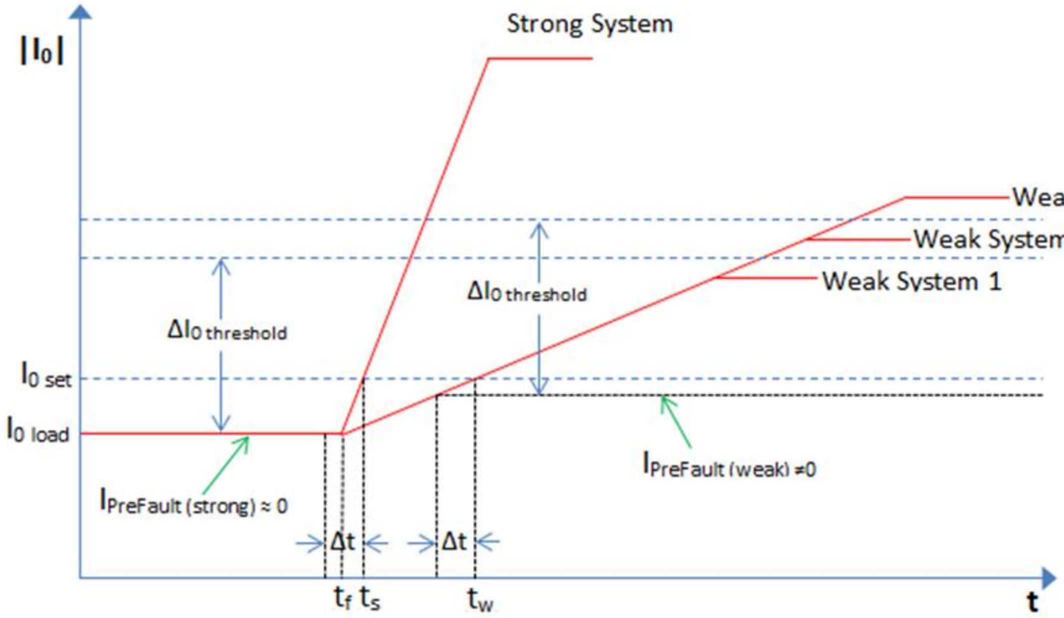
C.1.2 Blocking of the relay based on fault type identification

Some relays use the fault type identification logic to supervise their trip signals. In such cases, correct fault type identification logic is critical for desired operation of the relay.

The possibility of failure of fault type identification under weak grid conditions is higher due to low fault current levels. The level of vulnerability depends on the fault type detection method adopted by specific relay vendors. Some algorithms may not be vulnerable at low fault current levels as others.

The fault type identification algorithm used in this study is described below. This algorithm is vulnerable under low fault current levels.

Figure 43 Operation of fault type identification logic under different network conditions



The variation of the zero sequence fault current as calculated by the relay immediately following a fault is shown in Figure 43. The zero sequence current estimated by the relay under a strong grid condition and three weak grid conditions is depicted in Figure 43.

A fault is applied at tf (|I0| is close to zero prior to the fault for all system condition cases). After the fault inception, |I0| of the strong system increases rapidly compared to that of power systems with low system strength. Therefore, the fault in strong system is picked up at time ts while the fault in power systems with low system strength is picked up at time tw. Those are the respective times for |I0| to reach I0 set value (I0 set should be set in such a way that the relay does not operate for zero sequence currents due to acceptable system unbalances).

The fault type identification algorithm works on the principle of current superposition. The fault current (zero sequence component) is estimated by subtracting the pre-fault zero sequence current (load current) from the current measured during a fault. If this estimated fault current is above the ΔI0 threshold, further calculations will be performed to identify the fault type.

If this estimated fault current is below the ΔI0 threshold, the fault type identification calculations are not activated and the relay operation will be blocked.

This calculated zero sequence fault current can be below the ΔI0 threshold due to two main reasons under weak grid conditions:

- Actual fault current is below I0 threshold

  In the system 1 with low system strength in Figure 43, the calculated fault current (= measured current during a fault – load current) is below the I0 threshold due to reduced fault current contribution from wind turbines. The I0 threshold should be carefully selected in weak grid conditions.

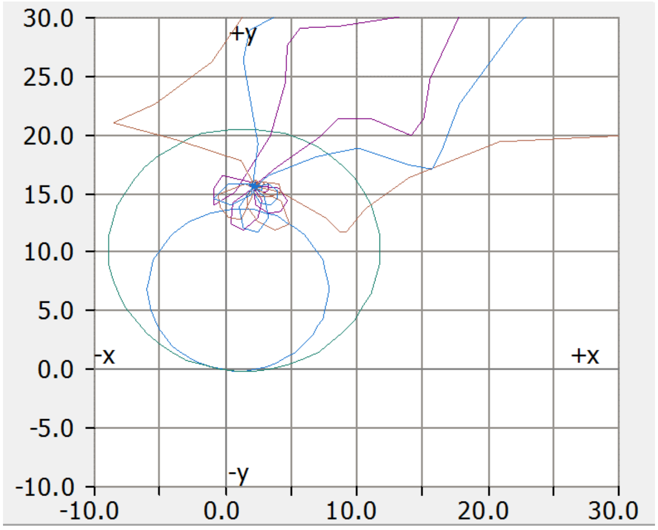
- Errors in the calculated fault current

  In the system 2 with low system strength in Figure 43, the calculated fault current (= measured current during a fault - IPreFault (weak)) is below the I0 threshold due to storage of incorrect pre-fault current. Pre-fault current is calculated based on the time of fault detection and the memory current of n previous sample times (n = 1, 2 …). In this example, n=1. Due to the slow increase of |I0|, previous memory currents include some portion of fault current. Therefore, the calculated fault current will be low (compared to actual) resulting in a failure of fault identification logic.

C.1.3 Zone over-reach during transients

In low system strength conditions, the measured impedance during a transient following a fault, may travel around the final impedance point before it comes to its final impedance point (see Figure 44). This impedance trajectory may enter an inner zone during this transient period that may lead to an unexpected trip signal. There is a certain time duration (few sample times that vary based on vendor's algorithm) that this impedance point needs to stay inside a zone for the relay to issue a trip signal. Due to weak grid conditions, there may be cases (if the fault is closer to a zone border) where the impedance trajectory travel inside an inner zone for more than the tolerance time.

Figure 44 Impedance trajectory of a power system with low system strength followed by a three phase to ground fault



C.2 Case study

C.2.1 Methodology

A case study that investigated the impact of system strength on distance protection operation was carried out for the SA *power system*, where a two-step assessment was used.

The first step of the assessment investigated 15 different minimum *synchronous generation dispatch* scenarios cases identified in SASSA. Fault current calculations were conducted with each generator *dispatch* case for different *contingency events*. For each *contingency event*, a fault was applied at either side of a *transmission line*, and the three phase fault current contribution from both sides of the faulted *transmission line* were calculated using PSS®E. Faults at both ends of the same *transmission line* were investigated.

For example, for faults at the Canowi–Robertstown 275 kV circuit, two three phase faults were investigated:

- Three phase fault at 5% line distance from the Robertstown *busbar*
- Three phase fault at 95% line distance from the Robertstown *busbar* (5% from Canowi)

For each of these faults, the three fault current contribution from both the Robertstown 275 kV *busbar* and Canowi 275 kV *busbar* were calculated in PSS®E.

The second step of the assessment will select the *synchronous generation dispatch* scenarios cases producing the lowest fault current contribution to the studied faults. The selected *synchronous generation dispatch* is then assessed using an EMT-type simulation with actual distance protection relay models and settings, to investigate whether such low fault current would cause maloperation of the distance *protection system*.

The same *contingency events* assessed in the first step assessment is simulated in the EMT type simulation. Different fault types, including single-phase-to-ground, phase-to-phase, two-phase-to-ground and three phase faults have been investigated to assess the performance of the *protection system*.

C.2.2 Study findings

From the first step assessment, three *synchronous generation dispatch* scenarios patterns were selected because they produced low fault currents in the SA *power system*. For several *contingency events*, the three phase fault current contribution calculated using PSS®E is lower than the *transmission line* rating, which indicates high risk of distance protection maloperate for *contingency events* on these circuits. Such *contingency events* are listed in Table 18:

Table 18 Contingency events with three phase fault current lower than transmission line rating

Contingency ID	Line Voltage (kV)	Line Rating (kA)	Three Phase Fault Current Contribution (Fault @ Close end)	Three Phase Fault Current Contribution (Fault @ Remote end)
1919	275	0.999	1.336	0.662
1945	275	0.900	0.870	0.572
1951	275	1.240	0.977	0.792
1827	132	0.779	0.789	0.431

It can be seen that for contingencies 1945 and 1951, the fault current from the line is less than the line rating even when the fault is at the close end of the line (Zone 1 of the close end distance *protection* relay).

The EMT-type study shows these *contingency events* all caused maloperation of distance *protection system*, which are listed in Table 19:

Table 19 Maloperation of protection system identified in EMT type simulation

Contingency ID	Fault Type	Failure to Operate	Reason for Failure
1919	Three phase to Ground	No, but operation not desired	Transient oscillation of impedance point during fault causes Zone 1 trip on **remote end**.
1945	Single Phase to Ground	Yes	Fault type identification blocks **remote end** alarm and trip signal
1951	Single Phase to Ground	Yes	Fault type identification blocks **close end** alarm signal and **remote end** Alarm/Trip signal.
1827	Single Phase to Ground	Yes	Fault type identification blocks **close/remote end** alarm and trip signals.

C.3 Conclusion

The case study demonstrates that a two-step assessment was used to assess the impact of system strength on the correct operation of distance *protection systems*. The first step screening method could identify certain *synchronous generation dispatch* scenarios with which the distance *protection system* might maloperate following certain *contingency events*. From the above studies, a simple assessment metric is used which compares the *transmission line* fault current contribution to its winter rating. The *transmission line* fault current contribution can be calculated using PSS®E.

A more detailed assessment using PSCAD™/EMTDC™ simulation demonstrated that with the selected Synchronous Machine *dispatch* scenarios, distance *protection* system mal-operation were identified following contingencies on lines where the calculated *transmission line* fault current contribution was less than the line winter rating in step 1 assessment.

The above screening method can be used to identify the minimum acceptable *synchronous generation dispatch* scenarios to be used in the assessment described in Section 9.1. As indicated in the screening method, when the calculated PSS®E fault current is less than the *transmission line* rating, it is more likely to cause protection to maloperate following *contingency events*, as later observed in the PSCAD™/EMTDC™ assessment. The following modified screening method should be used to assess *protection system* operation during the assessment as described in Section 9.1 of the Methodology:

- For a specified *transmission line*, calculate the three phase fault current for faults at the following location:
  - Three phase fault at 5% from one end of the line
  - Three phase fault at 5% from the other end of the line

- Calculate the three phase fault current contribution from both ends of the line to each of the above faults
  - The fault current calculation should use the same methods as described in Section 9.1.2. The total fault current, including contribution from *asynchronous generation*, should be calculated.

The minimum acceptable *synchronous generation dispatch* scenarios must ensure the fault current contribution from the closer end of the *transmission line* to the fault is higher than the highest rating of *transmission line* as advised by TNSPs.