INTEGRATING RENEWABLE ENERGY - WIND INTEGRATION STUDIES REPORT

For the National Electricity Market (NEM)

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EXECUTIVE SUMMARY

The National Electricity Market (NEM) design incorporates several features which will assist in effectively managing the expected 8.88 GW of new wind generation forecast to connect to the power system by 2020.

Nevertheless, integrating this level of new wind generation will present challenges in operating the power system and the electricity market. These challenges are expected to arise first in South Australia and Tasmania, where forecast levels of wind generation are highest compared to demand.

Further challenges are expected to arise from technological innovations, including increased distributed generation such as rooftop PV; and from changing consumer behaviour contributing to a trend of declining electricity consumption from the power system.

What this report provides

This is a technical report that explores how increased levels of wind generation will affect network and operational limits in the NEM.

Previous work by AEMO on the large-scale integration of wind generation recommended an assessment of the challenges presented by the particular technical and operational characteristics of the NEM. This document is the second of two publications that report on AEMO's assessment of some of these challenges.

The first report, on Wind Turbine Plant Capabilities, was published in June 2013. It provided information and assumptions about future wind generation performance. This second report focusses on the operational challenges presented by high levels of wind generation in the NEM.

Challenges to power system operation

AEMO forecast 8.88 GW of additional wind generation in the NEM by 2020 in its 2012 National Transmission Network Development Plan (NTNDP). This results in total installed NEM wind generation capacity of around 11.5 GW.

The key operational challenges to support this amount of wind generation in the NEM are:

- Power system inertia could be reduced due to displacement of conventional synchronous generation, particularly in South Australia and Tasmania. This would make control of power system frequency following contingency events more challenging in these regions.
- While power system frequency control in Victoria, New South Wales and Queensland would not be significantly affected, AEMO must make changes in Tasmania and South Australia to ensure ongoing control of power system frequency within required limits.
- Significant new wind generation can reduce existing interconnector transfer limits, particularly under conditions of low demand and high wind speeds when wind generation forms a large percentage of the generation mix.
- Early modelling indicates that, without action, up to 5,750 GWh and 1,260 GWh of the maximum potential wind generation energy in Victoria and South Australia respectively could be curtailed due to network limitations. This represents around 35% and 15% respectively of the energy potentially available from wind generation installed in these regions.
- Increasing levels of wind generation will reduce power system fault levels at some locations, which may lead to further limitations on the operation of wind generation and high voltage direct current (HVDC) links.

Options to address these challenges

AEMO could potentially manage these power system impacts with existing processes and systems. This could involve either using constraint equations in the central dispatch process to limit wind generation, or as a last resort by market intervention through issuing directions to synchronous generators to ensure sufficient levels of power system inertia are maintained to allow adequate control of power system frequency.

A number of other options could be considered to assist integration of this generation. These would require changes to processes, systems and regulatory instruments. Some of these involve:

- Establishing new ancillary service requirements to provide services that allow adequate control of power system frequency under conditions of low power system inertia.
- Investing to install purpose-built synchronous condensers to maintain system inertia and power system fault levels.
- Investing to allow some existing generating units to operate either with reduced minimum load or as synchronous condensers. This would allow existing generation to maintain system inertia and power system fault levels during periods of high wind generation.
- Establishing new control schemes, or modifying existing schemes, to ensure adequate control of power system frequency under conditions of low power system inertia.

AEMO will investigate the likely costs and potential benefits of these options, as well as considering any other feasible options or proposals identified by other parties.

Short-term actions

AEMO will complete the following by the end of 2013:

- Make changes to contingency frequency control ancillary services (FCAS) requirement calculations in Tasmania, to more accurately consider the response of Basslink and wind generation in Tasmania to power system disturbances.
- Make changes to contingency FCAS requirement calculations to consider power system inertia in South Australia, when the region is at risk of separation from the NEM.
- Better define the limits to power system operation with high rates of change of frequency, particularly in South Australia and Tasmania.

Longer-term actions

AEMO will improve its modelling of wind generation in its operational and planning tools and processes, to improve their accuracy with increasing levels of wind generation.

The focus of this study was the effects of transmission-connected wind generation on the power system. Other technologies, such as large-scale distribution-connected generation, may also affect power system operation.

This raises broader questions about the challenges facing the power system, market, and regulatory framework due to the pace of technological innovation altering the supply mix; and changing consumer behaviour, particularly in response to high electricity prices.

AEMO will provide further information on these issues before the end of 2013.

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CHAPTER 1 - INTRODUCTION

AEMO's 2012 National Transmission Network Development Plan (NTNDP)[1], published in December 2012, forecasts 8.88 GW of new wind generation for the National Electricity Market (NEM) by 2020. This is in addition to the 2.67 GW (approximately) installed as at May 2013.

Table 1-1 — Projected 2020 NEM wind generation

Region	Existing wind (MW)	Projected new wind by 2020 (MW)	Total 2020 wind (MW)	2012 minimum demand (MW)
QLD	0	266	266	4,098
NSW	265	2,117	2,382	5,124
VIC	884	4,090	4,974	3,780
SA	1,205	1,350	2,555	1,035
TAS	308	1,060	1,368	813
NEM	2,662	8,883	11,545	15,174

AEMO has been undertaking a range of wind integration studies to explore how well existing NEM systems, processes and arrangements are placed to integrate this generation, and what changes may be required.

AEMO's first wind integration studies were undertaken for the 2011 NTNDP. As part of this work AEMO conducted a review of world best practice for wind integration, and undertook an initial investigation of network impacts in the NEM. AEMO commissioned three international studies, covering:

- International practice and wind integration experience.
- A review of international grid codes.
- Lessons learned from international studies.

AEMO also undertook a series of market simulations which modelled thermal limits arising from the forecast new wind generation. This work was completed in December 2011; the details were published on AEMO's website.[2]

1.1 Current wind integration studies

Commencing in December 2012, AEMO's commenced studies to investigate how the 8.88 GW increase in wind generation forecast in AEMO's 2012 NTNDP might affect network and operational limits in the NEM. The purpose of these studies was for AEMO to understand the possible impacts of a "business as usual" approach to connecting this new generation, and to operating the NEM.

The current phase consists of:

- A study of current and projected wind generation grid performance (published June 2013).[3]
- A study of the impact of wind generation on power system operation (included in this report).
- Market modelling to quantify some of the impacts identified (included in this report).

The outcomes from these studies are as follows:

[1] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan.
[2] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Wind-Integration-Investigation.
[3] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Wind-Integration-Studies.

- To assist AEMO to anticipate and plan for operational impacts of large-scale wind generation.
- To enable better modelling of wind generation in future planning work.
- To identify possible requirements for changes to existing ancillary service arrangements.
- To inform AEMO's response to the Australian Energy Market Commission's (AEMC) proposed technical standards review.

1.2 Context for this report

AEMO's 2011 wind integration studies identified the need for technical studies considering the specific characteristics of the NEM, to investigate potential power system impacts resulting from high levels of wind generation. Potential impacts identified include:

- Wind generation can reduce power system inertia due to the economic displacement of synchronous generation. This has implications for power system frequency control.
- Procedures for operating islanded transmission networks (where parts of the power system have been electrically separated from the rest of the system) may require review.
- Wind generation typically has a lower fault level than the synchronous generation it displaces, resulting in reduced power system fault levels.
- Plant performance under unbalanced fault conditions, and the fast-acting control on power electronic devices such as wind generation, might require changes to power system modelling and limit analysis methods.
- Displacement of synchronous generation with power system stabilisers may impact power system damping.
- Series compensated lines and high voltage direct current (HVDC) network elements can interact with power electronic devices such as wind generation, giving rise to sub-synchronous resonance, which in turn can cause damage to generating plant.
- Methods of restarting the system from a black system condition might require review.

The 2011 wind integration studies suggest that increasing wind generation in the NEM may potentially have local impacts (thermal congestion or voltage control), inter-regional impacts (changes to interconnector utilisation or transfer limits), and system-level impacts (frequency control).

This report focusses on issues that affect real-time operation of the NEM as a large-scale interconnected power system, and those affecting inter-regional power system transfers. Of particular concern are issues related to control of power system frequency, where impacts arise from potentially large-scale economic displacement of conventional synchronous generation by wind generation.

The studies undertaken as part of this current report are informed by the "Lessons Learned from International Wind Integration Studies" report, produced as part of AEMO's 2011 studies. The recommendations considered when designing the current studies included the following:

- Evaluate stability impacts of wind power across the NEM as an integrated power system, rather than for individual regions.
- Consider the impact of wind generation on short-circuit levels.
- Consider the potential ability of wind power plants to support voltage and frequency.
- Use realistic wind turbine capability models in the system studies.

Market modelling

For this current report, AEMO used market modelling to quantify some of the potential impacts identified in the studies. Understanding the magnitude of a given impact on system operation, and how often it might be encountered, is important when considering what (if any) changes should be made to business-as-usual processes and systems.

Exclusions

This report focusses on the impacts of high levels of transmission-connected wind generation on the operation of the NEM as an integrated power system. Issues related to individual wind farm connections, such as local voltage control or network thermal loading, or issues confined to small sub-areas of the power system are not generally considered.

Such issues are typically considered either through the regional Annual Planning Reports produced by transmission network service providers (TNSPs), or through the connection processes for new generation.

While the potential impacts of increasing levels of distributed generation on power system operation are noted in a number of places throughout the report, this was not a main focus of this work.

This report does not assess how increased wind generation affects NEM reserve levels or power system reliability. NEM reserve levels are assessed as part of AEMO's Electricity Statement of Opportunity (ESOO)[4], and power system reliability is assessed in AEMO's Power System Adequacy (PSA)[5] reports.

1.3 Content and structure of this report

This report presents the findings of studies undertaken by AEMO to assess the potential impact of high levels of wind generation on network and operational limits in the NEM by 2020.

Chapter 2 - details the study assumptions used in this report; these are closely based on the planning scenario presented in AEMO's 2012 NTNDP, representing AEMO's forecast of the most likely state of the NEM in 2020. Assumptions that differ from, or were not taken from the 2012 NTNDP, are also described. Chapter 2 also outlines the interconnector limits selected for assessment. Further detail on the study methodologies, including a more granular breakdown of assumptions, is provided in Section 8.1.

Chapter 3 - presents the results of AEMO's investigation of the potential impacts of increased wind generation on power system frequency control, and on power system inertia levels. It provides background information on these issues, including a description of how they have historically been managed in the NEM. It projects how this may change as significant levels of new wind generation are introduced, and describes a range of options for mitigating or managing these issues going forward.

Chapter 4 - presents the results of AEMO's investigation of the potential impacts of increased wind generation on power system fault levels. It also describes several possible reasons why it may be necessary to maintain minimum amounts of synchronous generation online.

Chapter 5 - presents the results of AEMO's investigation of the potential impacts of increased wind generation on interconnector transfer limits. AEMO identified key existing NEM interconnector transfer limits based on voltage, transient and oscillatory stability, and made an assessment of how increased wind generation might modify these limits. Further detail about the methodology used to make these assessments is provided in Section 8.1.

Chapter 6 - provides a summary of the findings of this report with a focus on individual NEM regions.

Chapter 7 - summarises the market modelling work undertaken by AEMO to quantify some of the power system impacts identified in these studies. The findings of this work will help identify any changes that may be required to existing systems and processes to better manage or minimise some of the impacts identified.

Chapter 8 - contains supplementary information about the modelling methods and data used in this report.

Chapter 9 – contains a summary of units of measure and acronyms used in the report.

[4] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities.
[5] AEMO. Available: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/Power-System-Adequacy.

CHAPTER 2 - MODELLING ASSUMPTIONS

2.1 Introduction

This report considers the potential impact of wind generation on National Electricity Market (NEM) operation in the year 2020. The planning scenario outlined in AEMO's 2012 National Transmission Network development Plan (NTNDP) provides the basis for the assumptions in these current studies regarding new generation (including new wind generation), retirement of existing generation, demand, and network developments. Information on the modelling assumptions used in the NTNDP is presented in this chapter, in Chapter 8 -, and on AEMO's website.[6]

This report assumes a business-as-usual approach for NEM operation and new generation connections, and then assesses what network and operational impacts might arise. It identifies several options to mitigate or manage some of these impacts.

This report generally assumes system-normal operating conditions; that is, without any major transmission or generation outages, though it does also consider the potential impacts of a few key potential outages.

Key assumptions about future wind turbine performance are outlined in AEMO's "Wind Turbine Plant Capabilities Report" released in June 2013, and are available on AEMO's website.[7]

This report does not assess issues arising from individual wind farm connections, or those specific to small local areas within the power system. It focusses on "NEM-level" impacts of increased wind generation, including the following:

- Power system frequency control and inertia.
- Impact on interconnector capability arising due to transient, voltage and oscillatory stability limits.
- Power system fault levels.

2.2 Generation

The power system model assumed by AEMO for 2020 is based on the 2012 NTNDP. It includes significant new generation in the NEM, most of which is wind. It also includes smaller quantities of new thermal and utility-scale photovoltaic (PV) generation. Some retirement of existing generation is also assumed. Unless listed as retired in Table 2-13, all existing NEM generation is assumed to remain operational in 2020.

2.2.1 Existing wind generation

Table 2-1 to Table 2-4 list the existing NEM wind generation[8], which is assumed to remain operational in 2020. These tables do not include an additional 67 MW of smaller or older wind farm capacity across the NEM, as AEMO does not have real-time operational data for these wind farms. Further information about existing wind generation is available on AEMO's generation information webpage.[9]

Table 2-1 — Existing New South Wales wind generation

Region	Wind farm	Capacity (MW)	Dispatch type	Nearest grid connection
NSW	Capital	140	NS	Capital 330 kV
NSW	Cullerin	30	NS	Cullerin Tee 132 kV

[6] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Overview.
[7] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Wind-Integration-Studies.
[8] Includes both semi-scheduled (SS) and non-scheduled (NS) wind generation.
[9] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.

Region	Wind farm	Capacity (MW)	Dispatch type	Nearest grid connection
NSW	Gunning	47	SS	Cullerin Tee 132 kV
NSW	Woodlawn	48	SS	Capital 330 kV
Total		265		

Table 2-2 — Existing Victorian wind generation

Region	Wind farm	Capacity (MW)	Dispatch type	Nearest grid connection
VIC	Macarthur	420	SS	Tarrone 500 kV
VIC	Oaklands Hill	67	SS	Terang 66 kV
VIC	Mortons Lane	20	NS	Terang 66 kV
VIC	Yambuk	30	NS	Terang 66 kV
VIC	Challicum Hills	53	NS	Ballarat–Horsham 66 kV
VIC	Waubra	192	NS	Waubra 220 kV
VIC	Portland	102	NS	Portland 220 kV
Total		884		

Table 2-3 — Existing South Australian wind generation

Region	Wind farm	Capacity (MW)	Dispatch type	Nearest grid connection
SA	Bluff Wind Farm	53	SS	Belalie 275 kV
SA	Canunda	46	NS	Snuggery 132 kV
SA	Cathedral Rocks	66	NS	Port Lincoln 132 kV
SA	Clements Gap	57	SS	Redhill 132 kV
SA	Hallett Hill	71	SS	Mokota 275 kV
SA	Hallett (Brown Hill)	95	SS	Hallett 275 kV
SA	Lake Bonney Stage 1	81	NS	Mayura 132 kV
SA	Lake Bonney Stage 2	159	SS	Mayura 132 kV
SA	Lake Bonney Stage 3	39	SS	Mayura 132 kV
SA	Mt Millar	70	NS	Yadnarie 132 kV
SA	Snowtown	99	SS	Snowtown 132 kV
SA	Starfish Hill	35	NS	Willunga 132 kV
SA	Wattle Point	91	NS	Dalrymple 132 kV
SA	Waterloo	111	SS	Waterloo East 132 kV
SA	Nth Brown Hill	132	SS	Belalie 275 kV
Total		1,205		

Table 2-4 — Existing Tasmanian wind generation

Region	Wind farm	Capacity (MW)	Dispatch type	Nearest grid connection
TAS	Woolnorth	140	NS	Smithton 110 kV
TAS	Musselroe	168	SS	Derby 110 kV
Total		308		

2.2.2 New wind generation

AEMO uses the concept of "wind bubbles" to model expansion of wind generation. A wind bubble corresponds to a geographical area where:

- The wind resource is believed to be sufficiently attractive for wind generation development.
- All wind generation within the bubble is assumed to experience the same wind speeds.

Figure 2-1 shows the wind bubbles defined in AEMO's NTNDPs and used in this study.

Table 2-5 provides a list of the wind bubble abbreviations and names shown in Figure 2-1.

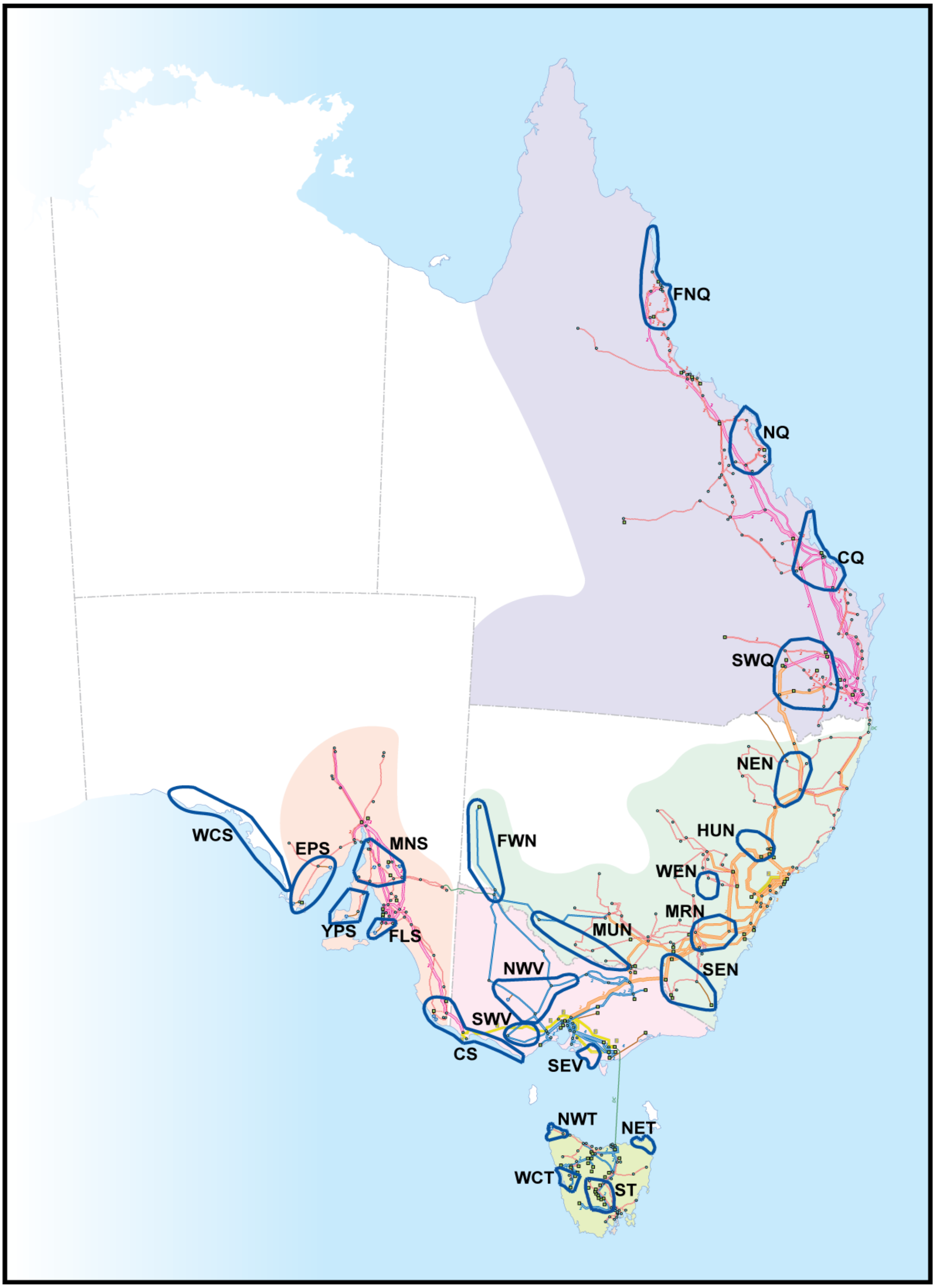
All new wind generation is assumed to be semi-scheduled.

Table 2-5 — NEM wind bubbles

Wind bubble abbreviation	Description and region
FNQ	Far North Queensland
NQ	North Queensland
CQ	Central Queensland
SWQ	South West Queensland
NEN	New England New South Wales
HUN	Hunter New South Wales
WEN	West New South Wales
MRN	Marulan New South Wales
MUN	Murray New South Wales
SEN	South East New South Wales
FWN	Far West New South Wales
NWV	North West Victoria
SWV	South West Victoria
SEV	South East Victoria
CS	Central South [Victoria and South Australia]
FLS	Fleurieu Peninsula South Australia
MNS	Mid North South Australia
YPS	Yorke Peninsula South Australia
EPS	Eyre Peninsula South Australia
WCS	West Coast South Australia

Wind bubble abbreviation	Description and region
NWT	North West Tasmania
NET	North East Tasmania
WCT	West Coast Tasmania
ST	South Tasmania

Figure 2-1 — NEM wind bubbles



New wind generation in this study is based on the planning scenario used in the 2012 NTNDP. Figure 2-2 and Table 2-6 to Table 2-10 show the new wind generation assumed for 2020 in this report.

Figure 2-2 — New wind generation for each wind bubble

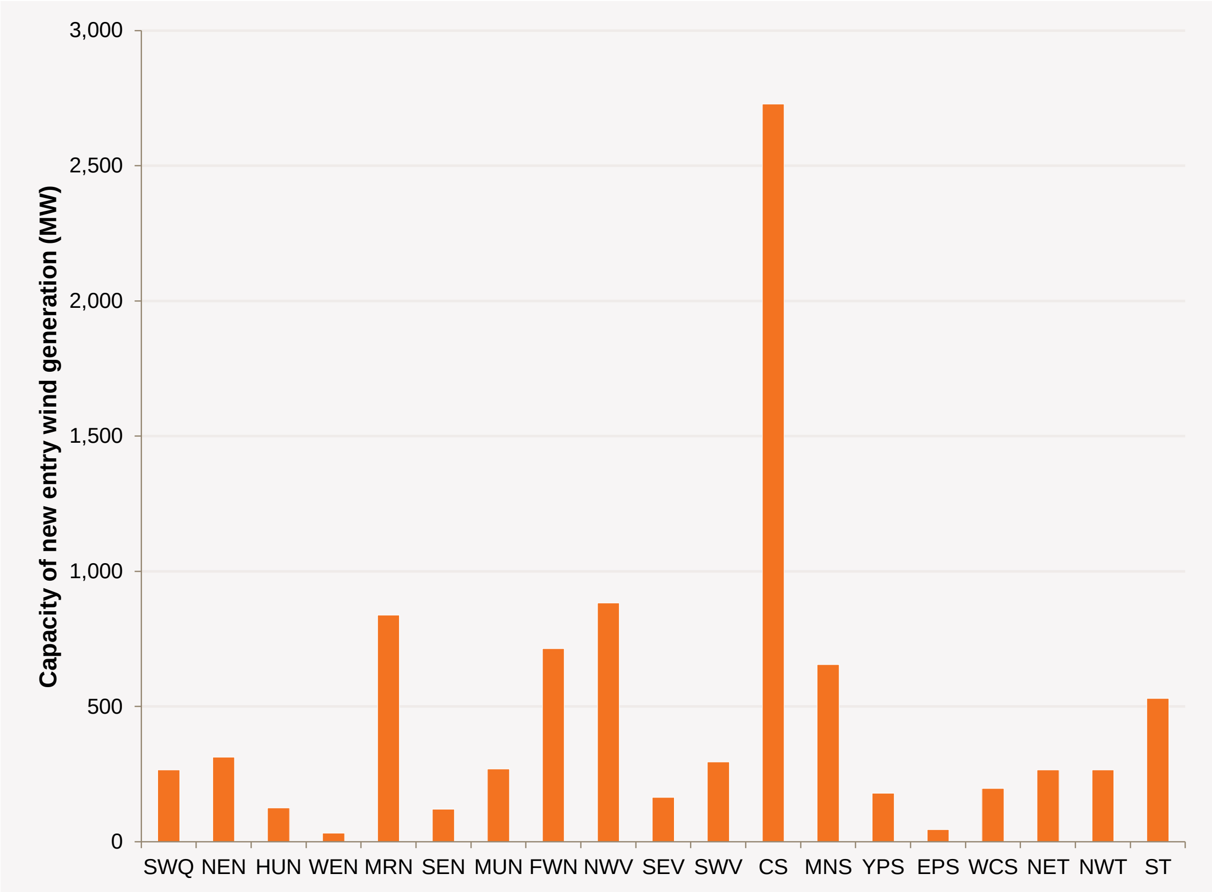


Table 2-6 — New wind generation in Queensland by 2020

Region	Wind bubble	2012 NTNDP wind farm name	Capacity (MW)	Connection point
QLD	SWQ	Blackstone_WIND	199.5	Blackstone 275 kV
QLD	SWQ	Greenbank_WIND	66.5	Greenbank 275 kV
Total			266	

Table 2-7 — New wind generation in New South Wales by 2020

Region	Wind bubble	2012 NTNDP wind farm name	Capacity (MW)	Connection point
NSW	FWN	Broken Hill_WIND	247.9	Broken Hill 220 kV
NSW	FWN	Buronga_WIND	172.1	Buronga 220 kV
NSW	MRN	Yass_WIND	681.7	Yass 330 kV
NSW	MUN	Deniliquin_WIND	96.4	Deniliquin 132 kV
NSW	MUN	Jindera_WIND	172.1	Jindera 330 kV
NSW	NEN	Armidale_WIND	313	Armidale 330 kV

NSW	SEN	Cooma_WIND	120.3	Cooma 132 kV
NSW	HUN	Bayswater_WIND	125.2	Bayswater 330 kV
NSW	MRN	Bannaby_WIND	156.5	Bannaby 330 kV
NSW	WEN	Wallerawang_WIND	31.3	Wallerawang 330 kV
Total			2,117	

Table 2-8 — New wind generation in Victoria by 2020

Region	Wind bubble	2012 NTNDP wind farm name	Capacity (MW)	Connection point
VIC	CS	Mortlake_WIND	1,227	Mortlake 500 kV
VIC	CS	Shaw River_WIND	613.5	Tarrone 500 kV
VIC	CS	Tarrone_WIND	613.5	Tarrone 500 kV
VIC	FWN	Red Cliffs_WIND	294.4	Redcliffs 220 kV
VIC	NWV	Ballarat_WIND	294.4	Ballarat 220 kV
VIC	NWV	Bendigo_WIND	294.4	Bendigo 220 kV
VIC	NWV	Horsham_WIND	294.4	Horsham 220 kV
VIC	SWV	Terang_WIND	294.4	Terang 220 kV
VIC	SEV	Hazelwood_WIND	164	Hazelwood B3/4 220 kV
Total			4,090	

Table 2-9 — New wind generation in South Australia by 2020

Region	Wind bubble	2012 NTNDP wind farm name	Capacity (MW)	Connection point
SA	CS	Krongart 275_WIND	274.5	Krongart 275 kV
SA	EPS	Port Lincoln132_WIND	44.8	Port Lincoln 132 kV
SA	MNS	Belalie 275_WIND	35.8	Belalie 275 kV
SA	MNS	Snowtown 2_WIND[10]	270	Blyth 275 kV
SA	MNS	Brinkworth 275_WIND	44.8	Brinkworth 275 kV
SA	MNS	Bungama 275_WIND	35.7	Bungama 275 kV
SA	MNS	Canowie 275_WIND	71.6	Canowie 275 kV
SA	MNS	Glenriver 275_WIND	62.6	Glen River 275 kV
SA	MNS	Mokota 275_WIND	35.8	Mokota 275 kV
SA	MNS	Robertstown132 kV_WIND	26.8	Robertstown 132 kV
SA	MNS	Robertstown 275_WIND	71.6	Robertstown 275 kV
SA	WCS	Cultana 275_WIND	44.8	Cultana 275 kV

[10] This new wind generation models the Snowtown 2 Wind Farm, currently under construction in South Australia.

SA	WCS	Lincoln Gap275_WIND	152.2	Lincolns Gap 275 kV
SA	YPS	PGW 275_WIND	179	Parafield Gardens West 275 kV
Total			1,350	

Table 2-10 — New wind generation in Tasmania by 2020

Region	Wind bubble	2012 NTNDP wind farm name	Capacity (MW)	Connection point
TAS	NET	George Town_WIND	265	George Town 220 kV
TAS	NWT	Burnie_WIND	265	Burnie 220 kV
TAS	ST	Derby_WIND	265	Derby 110 kV
TAS	ST	Waddamana_WIND	265	Waddamana 220 kV
Total			1,060	

2.2.3 New thermal and PV generation

AEMO assumed the following new thermal and utility-scale solar PV generation, based on the 2012 NTNDP planning scenario. New utility-scale PV plant locations are based on wind bubbles; new thermal generation is not.

AEMO generally considers rooftop PV generation as a reduction in load supplied from the transmission and distribution networks; it was therefore considered in the demand forecasts rather than as a source of supply.

Table 2-11 — New thermal generation in the NEM by 2020

Region	New generation type	Capacity (MW)	Connection point
VIC	Open cycle gas turbine	314	Hazelwood B3/4 220 kV
SA	Open cycle gas turbine	21.1	Torrens Island 275 kV
SA	Biomass	300	Krongart 275 kV
Total		635	

Table 2-12 — New utility-scale PV generation in the NEM by 2020

Region	Wind bubble	Solar plant name	Capacity (MW)	Connection point
QLD	NQ	SOLAR 1	66.7	Ross 275 kV
QLD	NQ	SOLAR 1	66.7	Strathmore 275 kV
QLD	NQ	SOLAR 1	66.7	Nebo 275 kV
VIC	CVIC	SOLAR 1	80	Redcliffs 220 kV
VIC	CVIC	SOLAR 1	80	Kerang 220 kV
VIC	CVIC	SOLAR 1	80	Shepparton 220 kV
VIC	CVIC	SOLAR 1	60	Bendigo 220 kV
VIC	CVIC	SOLAR 1	60	Horsham 220 kV
VIC	CVIC	SOLAR 1	40	Ballarat 220 kV
SA	NSA	SOLAR 1	400	Davenport 275 kV
Total			1,000	

2.2.4 Retirement or mothballing of generation

As per the 2012 NTNDP planning scenario, the following NEM thermal generation is assumed to be retired or mothballed by 2020.

Table 2-13 — Retired or mothballed NEM generation by 2020

Region	Fuel type	Capacity (MW)
QLD	Black coal	190
NSW	Black coal	1,644
VIC	Brown coal	884
SA	Brown coal	240
Total		2,958

2.2.5 Existing thermal and hydro generation capacity

Information on existing thermal and hydro generation in each NEM region can be found on AEMO's website.[11] Other than the generation listed as retired in Table 2-13, all existing thermal and hydro generation in the NEM is assumed to remain in service for 2020.

2.2.6 Dynamic modelling of new generation

A number of studies for this report required dynamic modelling of both existing and new generation in the NEM as at 2020. Existing AEMO dynamic models were used for existing thermal and hydro plant. Modelling of new thermal generation was based on modelling of comparable existing thermal generation in the NEM.

AEMO's Wind Turbine Plant Capabilities Report[12] published in June 2013, documents dynamic modelling assumptions used for different wind turbine models and utility-scale PV models. The report summarises the technical capabilities of existing wind turbines in the NEM and describes current developments in wind turbine capability that underpin AEMO's assumptions about how wind technology may evolve. All existing and new wind generation in this study was modelled using the typical wind generation models described in the Wind Turbine Plant Capabilities Report.

A "plausible minimum" performance scenario was assumed for new wind generation; it assumed that a larger proportion of generally lower-performing doubly fed induction generator (DFIG, type 3) wind turbines will be built rather than the generally higher-performing full converter (type 4) turbines. The breakdown between the two types of modelled new wind turbines was approximately 65% type 3 and 35% type 4, with type 4 selected for the largest individual projects.

AEMO assumed for the purposes of this study that the existing South Australia-specific ESCOSA Licence Conditions for Wind Generators[13] remains in place, and that all new wind generation in South Australia to 2020 will meet the performance requirements specified in these licence conditions.

2.3 Demand

Forecasts of future demand levels are a key input into any assessment of the future operation of the power system. Power system studies typically focus on maximum demand conditions, or other conditions that result in the heaviest loading on the power system. However, minimum demand and high wind conditions will typically result in wind generation forming the highest percentage of the generation mix, so minimum demand conditions are also an important study condition in this report.

AEMO used demand forecasts from the 2012 NTNDP in these studies. Specifically, the planning scenario 10% probability of exceedance (POE) demand traces for 2020–21 were used in market modelling for these studies. These were derived from the 10% POE demand forecasts originally reported in AEMO's 2012 National Electricity Forecasting Report (NEFR)[14], and were then modified to produce a forecast of the demand that must be met by the generation modelled in the 2012 NTNDP.[15]

Table 2-14 summarises the modelled 2020–21 NEM regional maximum and minimum demands considered in the market modelling for these studies, and shows actual 2012 maximum and minimum regional demands for comparison.

[11] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information.
[12] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Wind-Integration-Studies.
[13] AEMO. Available: http://www.escosa.sa.gov.au/projects/15/2010-wind-generation-licensing.aspx.
[14] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012.
[15] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/~/media/Files/Other/ntndp/2012NTNDP_DemandTracesDevelopment.ashx.

Table 2-14 — Modelled and actual regional demands

Region	2020–21 modelled 10% POE peak demand (MW)*	2020-21 modelled minimum demand (MW)*	Actual peak demand 2012 (MW)**	Actual minimum demand 2012 (MW)**
QLD	10,597	5,220	8,756	4,098
NSW	14,707	5,747	12,310	5,124
VIC	11,167	3,866	9,447	3,780
SA	3,566	809	2,997	1,035
TAS	1,946	894	1,721	813
NEM total	37,482	17,544	31,427	15,174

* Demand in NTNDP market modelling is "sent out" demand, which is measured as generation injected into the transmission grid. It excludes generation output that is consumed internally in power station house loads.

** "Actual peak" and "actual minimum" demands are based on five-minute "as generated' demand data obtained from AEMO's market systems. This demand includes the output of scheduled, semi-scheduled, and significant non-scheduled generators. It is higher than the market modelling demand where significant power station house loads are present.

2.4 Network augmentations

AEMO's studies for this report assumed that the transmission network augmentations considered to be "committed" in the 2012 NTNDP are in place by 2020. AEMO engaged the jurisdictional planning body in each NEM region to discuss potential network issues that could arise in 2020 based on the assumptions made in this study; these included new generation, demand forecasts, and network augmentation projects. The discussions were also important in refining methodologies and assumptions used in the power system impact assessments.

2.4.1 Heywood Interconnector upgrade

The proposed upgrade of the Heywood Interconnector between Victoria and South Australia is the most significant network upgrade modelled in this project. This upgrade is expected to raise the existing maximum transfer capability between Victoria and South Australia from 460 to 650 MW. Together with the Murraylink high voltage direct current (HVDC) Interconnector's existing 220 MW capability, Victoria and South Australia's maximum transfer capability is assumed to be 870 MW in both directions. Further details regarding the Heywood Interconnector upgrade are available on AEMO's website.[16]

2.5 Impacts on network limits

This study provides an initial assessment of the potential impact by 2020 of increased wind generation on several key interconnector limits in the NEM related to transient, voltage and oscillatory stability. Information is provided below on the methods and assumptions used in this assessment.

2.5.1 Identification of key interconnector limits

AEMO first reviewed the most material limits that currently determine inter-regional transfer capability in the NEM. These key limits were selected based on their relevance and historic binding statistics over the past five years. Only system-normal interconnector power transfer limits were considered.

AEMO assumed that existing wind generation was already accurately considered in the existing limits, and that they would remain valid in their existing form in 2020 in the absence of any new wind generation. Power system

[16] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T.

studies were then undertaken to determine offsets or adjustments to each of the existing key interconnector limits as a function of the new wind generation in each wind bubble.

Due to the planned upgrade of the Heywood Interconnector prior to 2020, new limit equations representing the Heywood Interconnector limits after the upgrade were used as a starting point; these limits were determined as part of the upgrade assessment process.

2.5.2 Key transient stability limits

Transient stability limits commonly set three inter-regional transfer capabilities in the NEM. These are:

- Queensland to New South Wales power transfer on the Queensland–New South Wales interconnector (QNI).
- Victoria to New South Wales power transfer on the Victoria – New South Wales interconnector.
- Victoria to South Australia power transfer on the Heywood Interconnector.

Table 2-15 summarises these existing transient stability limits, and the IDs of the existing constraint equations AEMO uses in central dispatch process to manage these limits.

Table 2-15 — Key existing interconnector limits based on transient stability

Transient stability limit description	Constraint equation ID
Limit flow from VIC to NSW to prevent instability for the fault and trip of a Hazelwood – South Morang 500 kV line.	V::N_NIL_S1 to V::N_NIL_S4 V::N_NIL_V1 to V::N_NIL_V4 V::N_NIL_Q1 to V::N_NIL_Q4
Limit flow from VIC to SA to prevent instability for the loss of the largest generation block in SA.	V::S_NIL_MAXG_AUTO
Limit flow from QLD to NSW to prevent instability for the fault and trip of a 330 kV line between Armidale and Bulli Creek.	Q:N_NIL_BCK2L-G
Limit flow from QLD to NSW to prevent instability for the trip of a Boyne Island smelter potline.	Q:N_NIL_BI_POT

2.5.3 Key voltage stability limits

Voltage stability limits commonly set three inter-regional transfer capability limits in the NEM, which are:

- New South Wales to Queensland power transfer on the Queensland – New South Wales Interconnector (QNI) and Directlink.
- New South Wales to Victoria power transfer on the Victoria – New South Wales Interconnector.
- Victoria to South Australia power transfer on the Heywood Interconnector.

A New South Wales intra-regional voltage stability transfer limit, the New South Wales limit from the Snowy region, was also studied due the significant forecast installation of wind generation in southern New South Wales.

Table 2-16 summarises these existing voltage stability limits, and the IDs of the existing constraint equations that AEMO uses in the central dispatch process to manage these limits.

Table 2-16 — Key existing interconnector limits based on voltage stability

Voltage stability limit description	Constraint equation ID
Limit flow from the Snowy region to NSW to prevent instability for the trip of Canberra – Lower Tumut 330 kV line.	N^^N_NIL_1
Limit flow from NSW to QLD to prevent instability for the loss of the largest generator in QLD.	N^Q_NIL_B N^^Q_NIL_B1 to N^^Q_NIL_B6

Limit flow from NSW to QLD to prevent instability for the trip of Liddell–Muswellbrook 330 kV line.	N^Q_NIL_A
Limit flow from VIC to SA to prevent instability for the loss of the largest generation block in SA.	V^^S_NIL_MAXG_AUTO
NSW to VIC to prevent instability for the loss of the largest generator in VIC.	N^^V_NIL_1
NSW to VIC to prevent instability for the trip of a Dederang – Murray 330 kV line.	N^^V_NIL_2

2.5.4 Oscillatory stability limits

There are two key oscillatory stability limits which currently set inter-regional transfer limits in the NEM under normal system conditions:

- Queensland to New South Wales power transfer on the Queensland – New South Wales Interconnector (QNI).
- South Australia to Victoria combined power transfers on the Heywood and Murraylink interconnectors.

Table 2-17 summarises these existing voltage stability limits, and the IDs of the existing constraint equations that AEMO uses to manage these limits.

Table 2-17 — Key existing interconnector limits based on oscillatory stability

Oscillatory stability limit description	Constraint equation ID
QNI oscillatory stability limit.	Q:N_NIL_OSC
SA to VIC oscillatory stability limit.	S:V_580

QNI oscillatory stability limit

For the last several years, flow south from Queensland to New South Wales on QNI has been limited to a maximum of 1,078 MW based on oscillatory stability. AEMO has historically understood that conditions of high Queensland to New South Wales flow on QNI potentially degrade at least one of the key inter-area modes of oscillation in the NEM, known as the “QNI” mode. This is a mode of oscillation between Queensland generators and generators in the rest of the NEM, with a frequency between 1.6 to 2.2 radians/sec.

The previous Inter-regional Planning Committee (IRPC) originally determined the QNI oscillatory limit to be 1,078 MW under system-normal conditions. This limit was reviewed in 2012 and an increased system-normal limit of 1,200 MW was endorsed by the Inter-network Test Working Group (INTWG). AEMO implemented this increased oscillatory stability limit on QNI southward flow in July 2013.

Work previously commissioned by AEMO also suggests that flows above 1,200 MW can be achieved on QNI while still maintaining adequate system damping. For the purposes of this report, AEMO and Powerlink agreed to assume a 1,400 MW limit for southward flow on QNI based on oscillatory stability for the 2020 scenario. This essentially assumes that the oscillatory stability will not materially limit southward flow from Queensland to New South Wales on QNI in 2020 for system-normal conditions. An assessment of the reasonability of the assumption is provided in Section 5.4.1.

Real-time measured damping of the QNI oscillatory mode has improved noticeably after installing and tuning Power Oscillation Dampers (PODs) at key static VAR compensators (SVCs) in south-east Queensland. AEMO anticipates that the QNI mode damping can continue to be improved, particularly with the recent commissioning of a new POD on the SVC at Armidale in northern New South Wales.

South Australia to Victoria oscillatory stability limit

The combined South Australia to Victoria power transfer on the Heywood and Murraylink interconnectors can be limited by oscillatory stability. AEMO understands that, historically, high South Australia to Victoria export conditions on Heywood and Murraylink have potentially degraded at least one of the key inter-area modes of oscillation in the NEM, known as the “I25” mode. This is a mode of oscillation between South Australia and Queensland generators combined against New South Wales generators, with a frequency usually between 2.4 to 3.1 rad/sec.

Following review, the INTWG endorsed an increase in the limit for combined flow on the Heywood and Murraylink interconnectors from 460 to 580 MW in 2010. AEMO implemented this 580 MW limit in January 2011. Since then, the South Australia to Victoria export is more likely to be limited by the thermal capacity of the two Heywood 500/275 kV transformers. This limit will increase with the installation of a third Heywood transformer, which is currently expected to be commissioned in mid-2016. This will lift the current thermal limitation on the Heywood transformers from 460 to 650 MW.

An indicative study performed by AEMO and ElectraNet in 2011 suggests that this oscillatory stability limit could be increased beyond the thermal limitation of 870 MW on combined Heywood and Murraylink export from South Australia to Victoria with some relatively low-cost control modifications such as retuning of PODs installed at Para SVCs. For the current studies, AEMO and Electranet agreed to assume an 870 MW limit for the 2020 scenario.

An assessment of the reasonability of these assumptions is provided in Section 5.4.2. Further information on the technique used by AEMO to make these assessments is provided in Section 8.1.3.

CHAPTER 3 - FREQUENCY CONTROL AND INERTIA

3.1 Introduction

This chapter presents the results of AEMO's assessment of the potential impact of significant new wind generation on power system frequency control and inertia. This work identifies possible changes that could be considered to better manage or mitigate some of the impacts identified.

3.2 Frequency control in the National Electricity Market

Managing power system frequency within specified limits is one of AEMO's key day-to-day responsibilities in its role as a power system operator. To achieve this, AEMO must keep generation and load in very close balance at all times. The key mechanism AEMO uses to balance generation and load is the central dispatch process, which includes the dispatch of both energy and frequency control ancillary services (FCAS).

3.2.1 Central dispatch and wind generation

The central dispatch process operates on a five-minute cycle, where generators are centrally scheduled based on an economic merit order determined by their supply offers to meet a load forecast five minutes in the future.

Since 2009 new wind farms registered in the National Electricity Market (NEM) larger than 30 MW have been required to participate in the central dispatch process. However, approximately 1,100 MW of wind generation registered before 2009 is non-scheduled (can self-dispatch), and does not participate directly in the central dispatch process.

To include wind generation in the central dispatch process, AEMO develops forecasts of maximum potential wind generation capacity using the Australian Wind Energy Forecasting System (AWEFS).[17] These forecasts are developed for a range of timeframes from five minutes ahead to two years ahead. They allow variable wind generation to be included in the central dispatch process in a manner similar to conventional synchronous generation. Forecasts are produced for all wind farms, including those not participating in the central dispatch process, to allow generation output outside the central dispatch process to be considered in the load–generation balance.

Given its very low marginal cost, wind generation normally aims to run at full capacity at all times, subject only to the available wind and any network limits or congestion. Wind generation capacity is normally offered for dispatch at very low (often negative) prices, and is typically the lowest-priced source of supply available.

Other future large-scale renewable generation technologies, such as utility-scale PV systems, will be required to participate in the central dispatch process. AEMO is currently developing the Australian Solar Energy Forecasting System (ASEFS) to provide forecasts of the maximum unconstrained output of utility-scale PV systems over a range of timeframes.

3.2.2 Frequency control ancillary services

Over timeframes shorter than the five-minute central dispatch cycle, imbalances between load and generation are managed in the NEM using frequency control ancillary services (FCAS). Two types of FCAS are used—regulation FCAS, and contingency FCAS—to manage two different causes of load–generation imbalances.

Regulation FCAS is used to control deviations in power system frequency arising from the generally small mismatches that occur between generation and load within the five-minute central dispatch process. These can occur due to errors in future load forecasts; errors in future wind generation output forecasts; generators moving

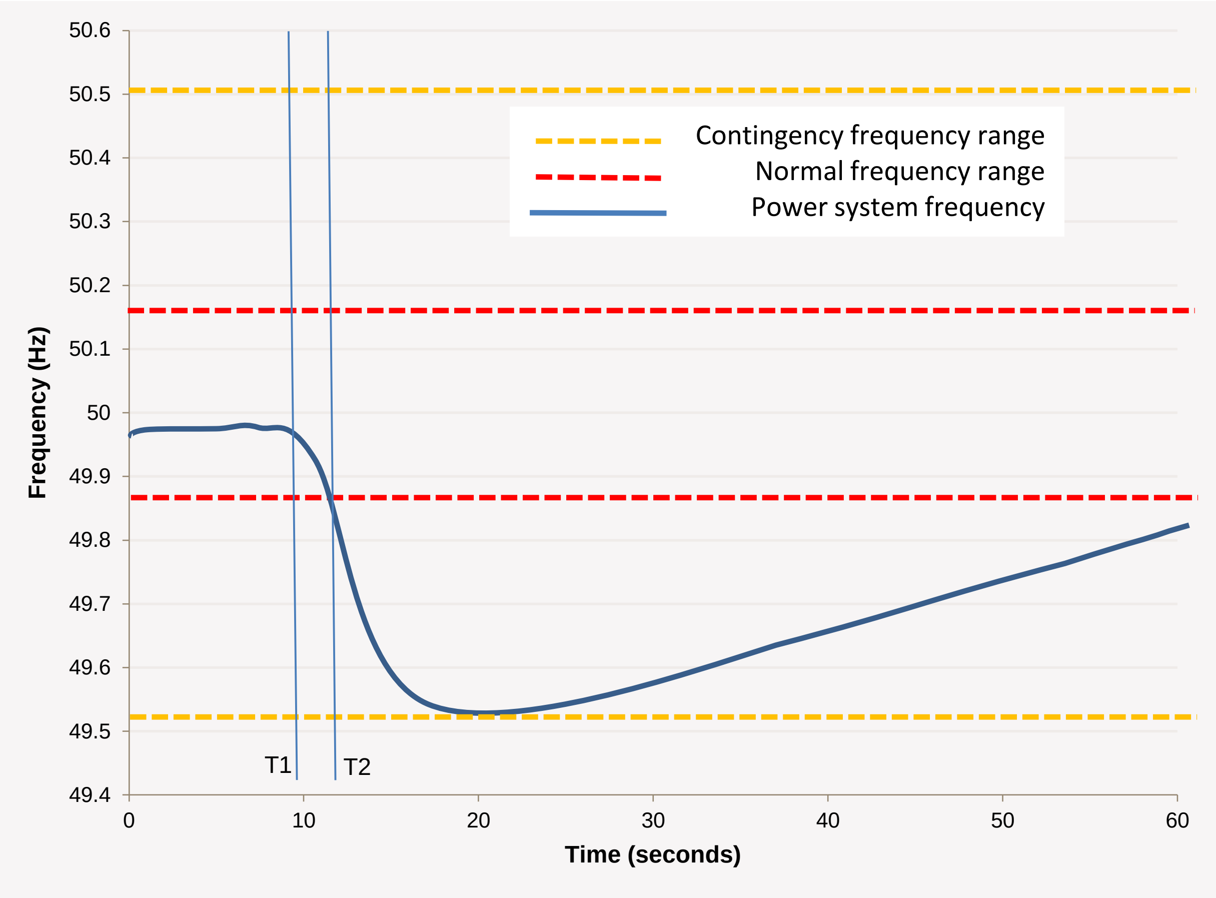
[17] AEMO. Available: http://www.aemo.com.au/~/media/Files/Other/electricityops/0260-0007%20pdf.ashx.

from one target operating point to another in a way that does not exactly track load changes; generators not correctly following their central dispatch targets; or a combination of these.

Contingency FCAS is used to manage changes in power system frequency arising from the larger load–generation imbalances that occur following a sudden unplanned disconnection of a large load or generator from the power system (a contingency event).

Figure 3-1 below shows the control of frequency in the NEM during normal operation, and following a contingency event. In this figure, a contingency event (loss of generation) occurs at the time shown as T1, resulting in a fall in power system frequency, which leaves the normal frequency operating range at T2. After T2, contingency FCAS would be used to arrest the fall in frequency, and to begin restoring frequency to the normal range.

Figure 3-1 — Frequency control in the NEM



Every five minutes, AEMO determines the quantities of regulation and contingency FCAS required, and both generators and loads then bid in a real-time FCAS market to supply these services. In practice, the majority of FCAS requirements are obtained from generators, though some large industrial loads do also provide them.

Generators are not obliged to participate in FCAS markets, and since NEM commencement in 1998, very few new entry generators have chosen to do so. No wind farms currently operating in the NEM have registered to participate in FCAS markets, and these studies assume that none will choose to do so by 2020.

The NEM FCAS markets are currently of very low value relative to the NEM energy market. In calendar year 2012 the total value of all FCAS markets in the NEM was $24.6 million[18], compared to $8.8 billion for the NEM wholesale energy spot market for the same period.

Further background information on NEM frequency control arrangements can be found on AEMO's website.[19]

3.2.3 Frequency Operating Standards

The NEM Frequency Operating Standards[20] specify the required ranges within which power system frequency must be maintained for a range of system operating conditions, including:

- Normal operating conditions, where frequency is controlled using regulation FCAS.
- Following a contingency event, where frequency is controlled using contingency FCAS.
- Following non-credible multiple contingency events.
- For events resulting in separation of parts of the power system.

The frequency of the Tasmanian and mainland power systems are not the same, because the Tasmanian power system is connected to the mainland via an asynchronous high voltage direct current (HVDC) link, rather than through a synchronous alternating current (AC) link.

Separate Frequency Operating Standards are specified for the Tasmanian power system due to its different technical characteristics. Different Frequency Operating Standards are also specified for areas of the power system that have been temporarily disconnected (islanded) from the rest of the power system.

These Frequency Operating Standards ultimately determine the quantity of FCAS AEMO requires for frequency control. The most important NEM Frequency Operating Standards are summarised below in Table 3-1.

Table 3-1 — Key NEM Frequency Operating Standards

Condition	Mainland (interconnected)	Tasmania (interconnected)	Mainland (islanded region)	Tasmania (islanded region)
Accumulated time error	5 seconds	15 seconds	-	-
Normal operation	49.85 to 50.15 Hz 99% of the time 49.75 to 50.25 Hz at all times	49.85 to 50.15 Hz 99% of the time 49.75 to 50.25 Hz at all times	49.5 to 50.5 Hz	49 to 51 Hz
Single load or generation trip	49.5 to 50.5 Hz	48 to 52 Hz	49 to 51 Hz	48 to 52 Hz
Multiple load or generation trip	47 to 52 Hz	47 to 55 Hz	47 to 52 Hz	47 to 55 Hz
Separation event	49 to 51 Hz	47 to 55 Hz	49 to 51 Hz	47 to 55 Hz

3.2.4 Regulation FCAS

Regulation FCAS allows AEMO to correct small deviations in frequency under normal operating conditions. There are two types: lower regulation FCAS and raise regulation FCAS.

When a generator provides AEMO with lower regulation FCAS, the generator's output can be reduced by AEMO's Automatic Generation Control (AGC) system during periods when the power system frequency is observed to be increasing, to restore frequency to 50 Hz.

[18] AEMO. Available: http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Ancillary-Service-Payments.
[19] AEMO. Available: http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services.
[20] AEMO. Available: http://www.aemc.gov.au/panels-and-committees/reliability-panel/standards.html.

When a generator provides AEMO with raise regulation FCAS, the generator's output can be increased during periods when the power system frequency is observed to be falling, to restore frequency to 50 Hz. To provide raise regulation FCAS to AEMO, a generator must operate below its maximum output, and "reserve" some of its capacity so AEMO can increase its output for power system frequency control.

While there is no basic technical reason why wind generation could not be operated in this way to provide raise regulation FCAS, it conflicts with normal wind farm operation, which is to maximise generation at all times, particularly given the typically low value of the FCAS market relative to the energy market.

Assuming the necessary control facilities were installed, there is also no obvious reason why wind generation could not provide lower regulation FCAS.

Under normal operating conditions the amounts of raise and lower regulation FCAS required by AEMO are fixed, pre-determined amounts. Separate regulation FCAS requirements are specified for the entire NEM including Tasmania (i.e., global regulation FCAS requirements), and for Tasmania only.

When the NEM commenced in 1998 the global raise and lower regulation FCAS requirements were 250 MW each. These have been progressively reduced to 120 MW lower and 130 MW raise, based on empirical factors such as improved load forecasting performance, operational experience, and observation of the NEM's long-term frequency regulation performance.

All mainland regions experience the same power system frequency, and AEMO can obtain global regulation FCAS from generators located within any mainland region. As described later, global regulation FCAS can also be sourced from Tasmania via the Basslink Interconnector. FCAS transfers across Basslink are described further in Section 3.4.2.

The Tasmanian raise and lower regulation FCAS requirements are both normally set at a fixed 50 MW. This must be available to the Tasmanian power system at all times; however, it also can be sourced either from generation within Tasmania, or from the mainland via Basslink.

There are existing automatic processes to increase the global regulation FCAS requirements from the normal value (120 or 130 MW) in several steps up to a maximum of 250 MW, based on the observed NEM real-time frequency regulation performance. This may be required if, for example, a sustained error in the automated load forecasting processes results in a sustained frequency deviation away from the normal frequency operating range.

There is currently no process to automatically adjust the Tasmanian local regulation FCAS requirements based on the observed frequency regulation performance in Tasmania, and no need to increase these requirements has been identified to date.

3.2.5 Contingency FCAS

Contingency FCAS are services provided by generators to correct larger deviations in power system frequency following unplanned disconnection of a large generator or load. Contingency FCAS are also classified as either raise or lower, for responding to a generator or load disconnection respectively.

AEMO obtains three different types of contingency FCAS to manage power system frequency over three different timeframes following a contingency. For the first six seconds following a contingency, a six-second contingency FCAS is used to arrest the immediate, rapid change in power system frequency and limit the minimum or maximum frequency that occurs.

Over the 60-second timeframe, 60-second contingency FCAS are used to return the frequency towards the normal operating range; and over the five-minute timeframe, five-minute contingency FCAS are used to fully correct the load–generation balance. These services are referred to as R6, R60 and R5 for raise contingency FCAS; and L6, L60 and L5 for lower contingency FCAS.

Because both five-minute contingency and regulation FCAS effectively provide the same service for controlling power system frequency, the requirement for these two services is co-optimised in the central dispatch process.

Like raise regulation FCAS, providing any of the three contingency raise FCAS requires a generator to operate below its maximum possible output, and to rapidly and automatically increase output in response to falling power system frequency. This can conflict with typical wind farm operation that seeks to maximise generation output at all times.

AEMO calculates the required quantity of each contingency FCAS type every five minutes based on current power system conditions. Generators and loads who have previously registered their FCAS capabilities with AEMO then provide offers in a real-time market to supply these various contingency FCAS requirements to AEMO.

Like regulation FCAS, AEMO uses separate calculations for contingency FCAS requirements for the NEM globally, and for Tasmania alone. Due to the Tasmanian power system's different technical characteristics and the characteristics of the Basslink Interconnector, Tasmania requires a more technically complex calculation of contingency FCAS requirements. Again, these different contingency FCAS requirements can usually be sourced from either the mainland, or from Tasmania via the Basslink Interconnector, as described in Section 3.4.2.

The current calculation of NEM global contingency FCAS requirements considers:

b) Size of the largest single load or generation contingency.

c) Power system load (to model frequency-dependent load relief).

Contingency FCAS requirements are highest for large contingency sizes and low load conditions.

In addition to these two factors, calculating contingency FCAS requirements for Tasmania also considers the inertia of the Tasmanian generating units, as contingency FCAS requirements increase under low Tasmanian power system inertia conditions. AEMO does not currently consider inertia when calculating contingency FCAS requirements other than in Tasmania. Further information on the calculations used to determine contingency FCAS requirements are available on AEMO's website.[21] Further information on power system inertia is provided in Section 3.3.

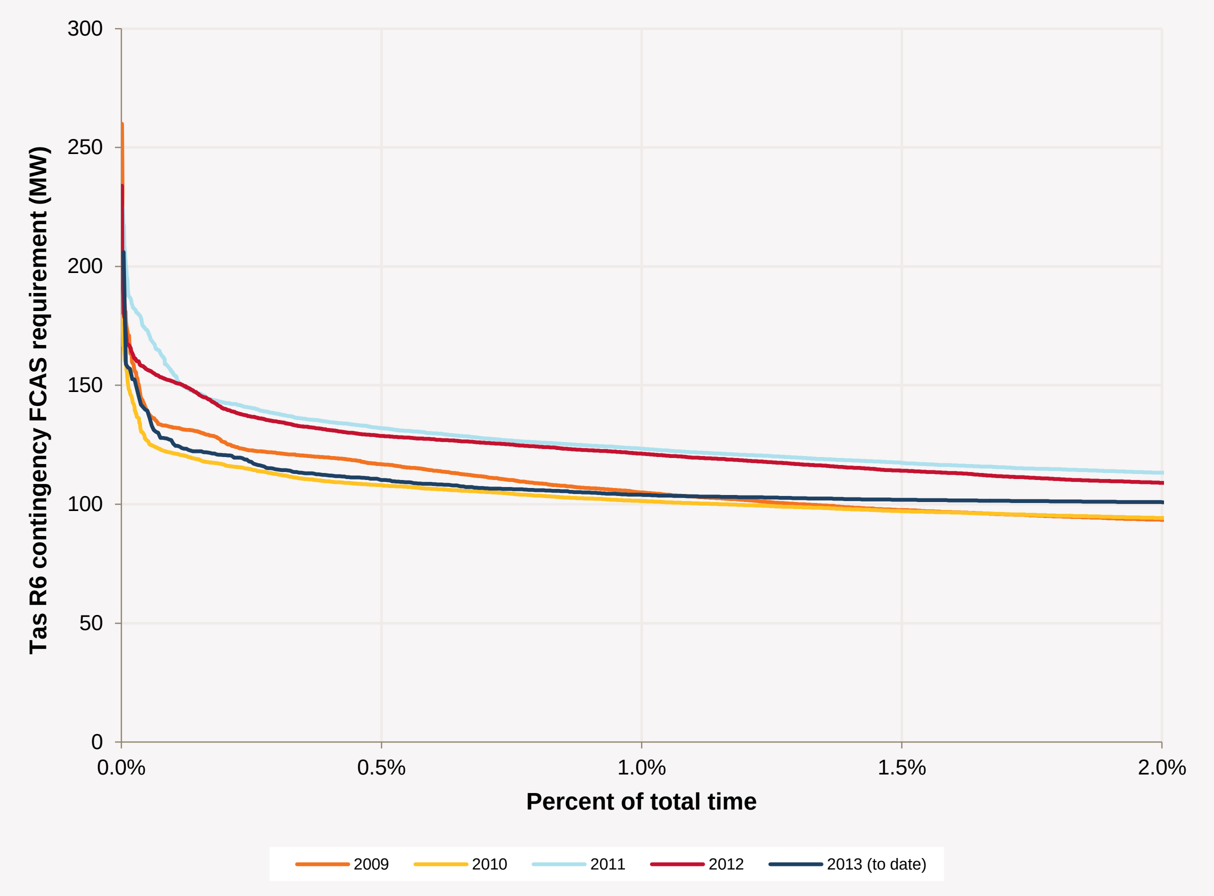
Under most operating conditions AEMO is able to source the required quantities of regulation and contingency FCAS at low cost. However, under some operating conditions it can be challenging for AEMO to obtain sufficient contingency FCAS, particularly in Tasmania. These conditions typically occur when Tasmanian demand is low, when there are few generators online, and when FCAS must be obtained from within Tasmania.

Approximately 64% of the total costs for NEM FCAS in 2012 were incurred for providing contingency raise FCAS.

Figure 3-2 below shows a partial time duration of R6 (six-second raise) contingency FCAS requirements in Tasmania over the last five years. It indicates that during a very small number of hours per year there is a large increase in R6 FCAS requirements. These periods are associated with conditions of low Tasmanian demand, large contingency size, and low power system inertia.

[21] AEMO. Available: http://www.aemo.com.au/Electricity/Market-Operations/Congestion-Information-Resource/Constraint-Implementation-Guidelines.

Figure 3-2 — Historical Tasmanian R6 FCAS requirements



Transend and AEMO are currently reviewing the calculation used to determine contingency FCAS requirements in Tasmania, due to the service of Musselroe Wind Farm. This review suggests the need to update this calculation to better consider the fault ride through behaviour of both Tasmanian wind generation and Basslink, and the behaviour of the Basslink Frequency Controller. Further information on these issues is provided in sections 3.6.8 and 3.4.1.

The technical issues identified in the contingency FCAS requirements calculation review in Tasmania suggest AEMO should consider similar factors in calculating contingency FCAS requirements in South Australia, when it is actually, or may become, islanded from the NEM.

3.3 Power system inertia

Power system inertia is a measure of the energy stored in the rotating masses of generators synchronised to the power system. If a generator is online, it provides a fixed amount of inertia to the power system; if it is disconnected, it provides no inertia. The amount of inertia a given generator provides is a constant value, which depends on the generator's design and size. Larger generators, those with more massive construction, and generators that operate at higher rotational speeds provide the most inertia to the power system. In this report inertia is measured in units of megawatt seconds (MW.s).

Power system inertia is lowest under conditions of low demand, when the fewest generators are connected to the power system. AEMO does not currently control inertia in any way—it is simply an observed characteristic of the power system, much like load level. AEMO currently operates the power system around the requirements that arise from the inertia levels that are present.

3.3.1 Effects of power system inertia

The level of inertia on a power system determines how fast the power system frequency will change following a disturbance that results in a load–generation imbalance. Under conditions of low power-system inertia, power system frequency changes more rapidly, as such changes require all synchronous generators connected to the power system to speed up or slow down correspondingly. In effect, when power system inertia is low, the power system can “accelerate” or “decelerate” more quickly. Conversely, when power system inertia is high, its frequency will change more slowly for a given disturbance.

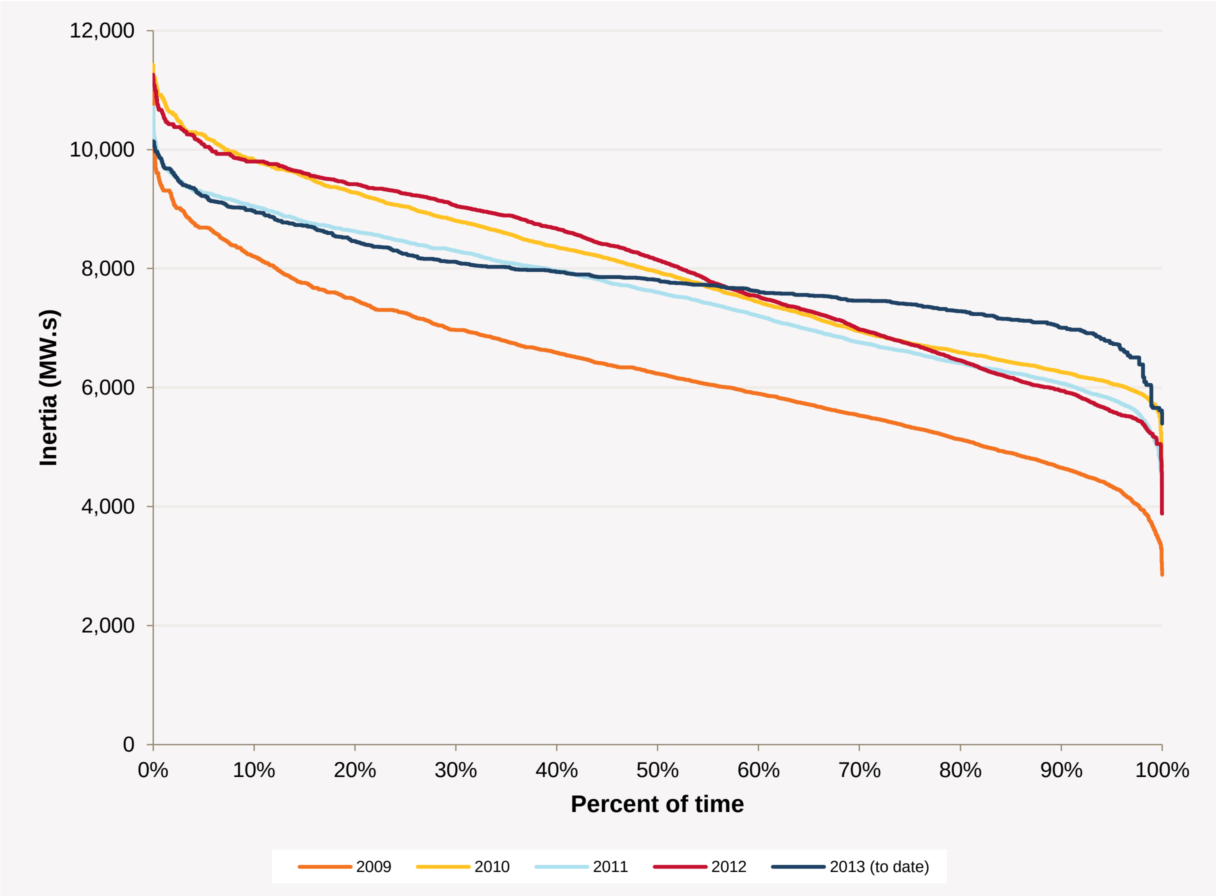
As inertia affects how fast power system frequency can change, it has implications for both calculating contingency FCAS requirements, and also more broadly when considering power system operation with high rates of change of frequency.

As power system frequency is normally the same at all mainland locations, the total inertia level on the mainland is normally the relevant factor determining how fast mainland frequency will change. During conditions when small NEM sub-regions become separated from the main body of the power system, the inertia of generators located only within those regions will determine frequency control in these regions.

Currently, AEMO always assumes mainland inertia levels to be high enough not to affect the calculation of mainland contingency FCAS requirements. As the Tasmanian power system is not synchronously connected to the mainland, Tasmania does not directly “see” mainland inertia. Inertia levels within Tasmania are much lower than the mainland, so managing Tasmanian frequency is more technically challenging; this is why power system inertia levels are considered when determining Tasmanian contingency FCAS requirements.

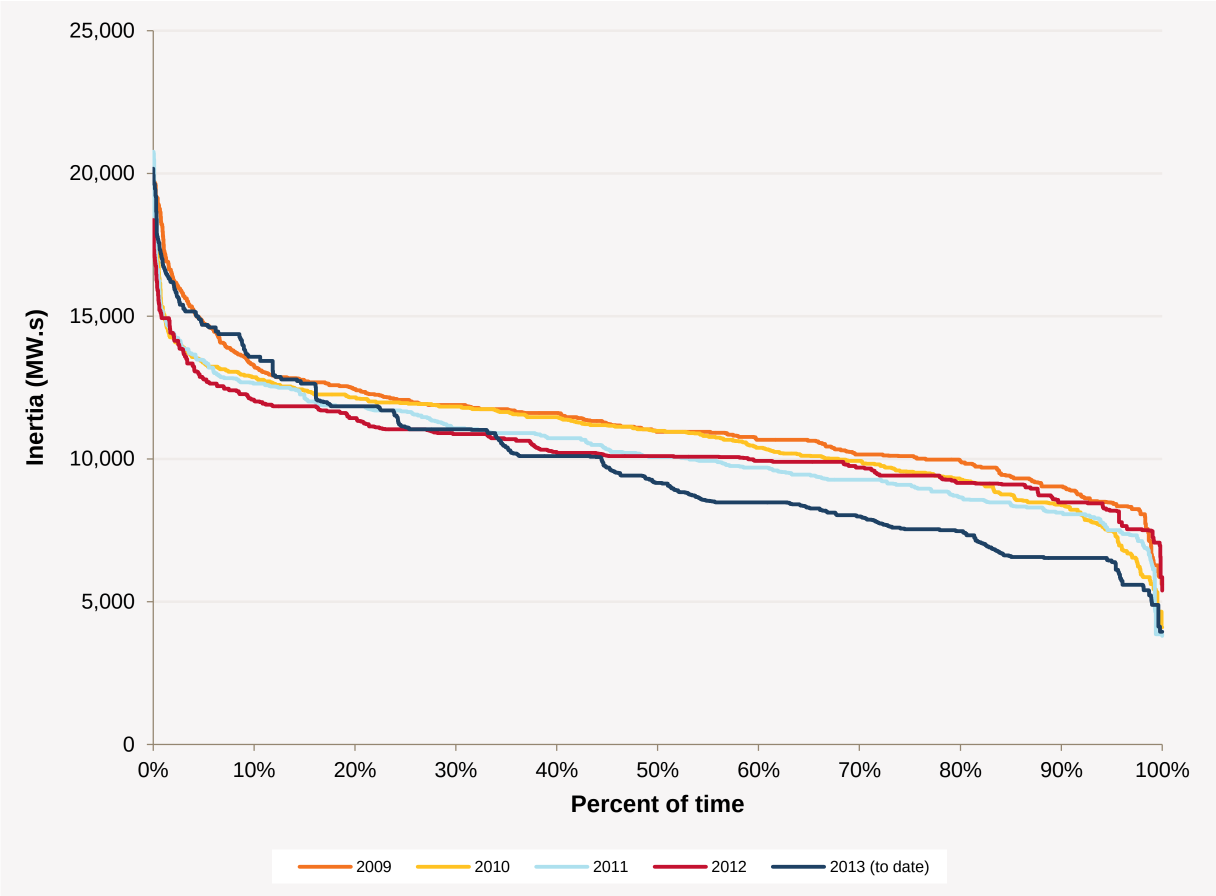
Figure 3-3 to Figure 3-5 below show the inertia distribution of the power system in Tasmania, South Australia, and the combined NEM mainland regions (Queensland, New South Wales, Victoria and South Australia) for the last five years. These three figures indicate that inertia in Tasmania is significantly lower than on the mainland. Data for 2013 is shown to the end of May.

Figure 3-3 — Inertia of Tasmanian power system



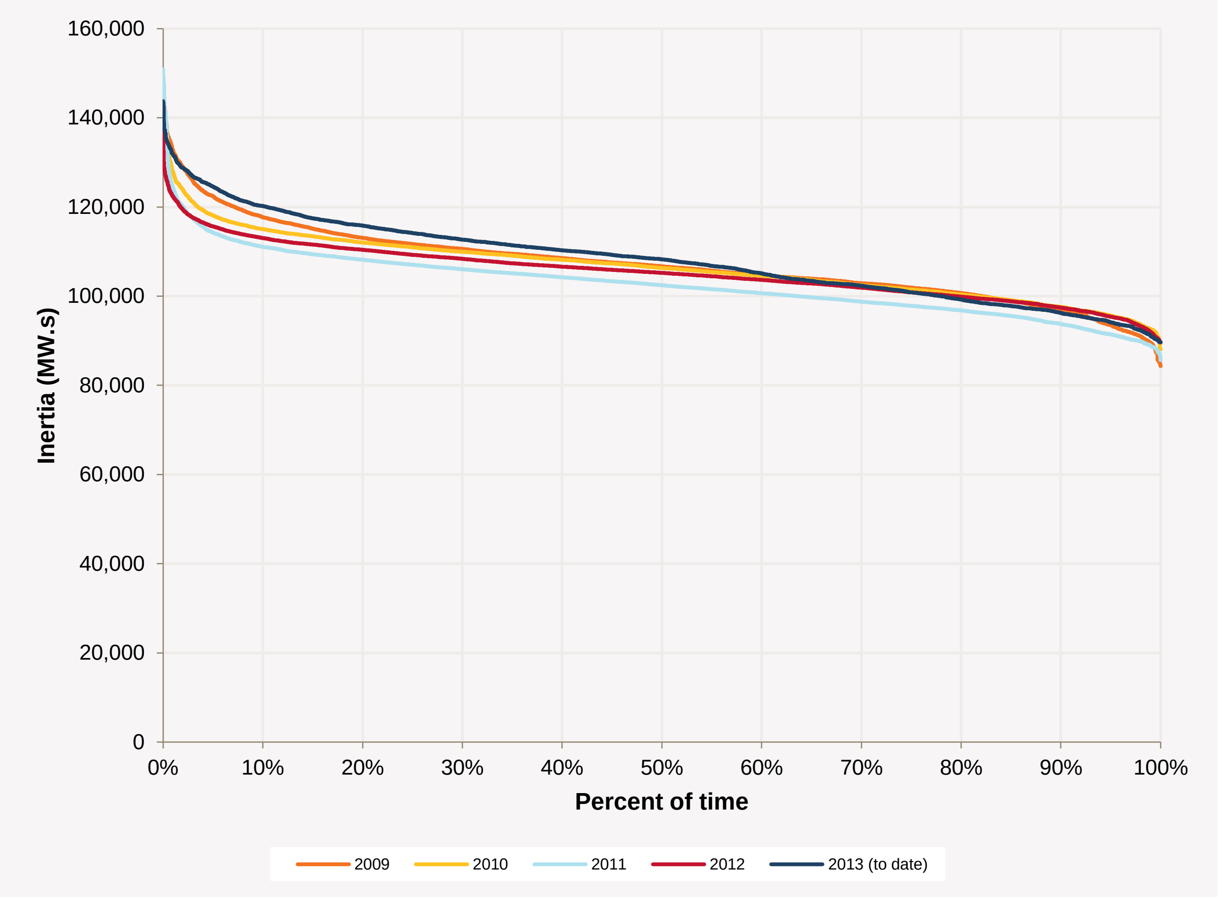
The increase in power system inertia seen in Tasmania after 2009 is mainly due to the commissioning of the Tamar Valley Combined Cycle Gas Turbine in that year; this generation type has relatively high inertia and it has operated with a high capacity factor since commissioning.

Figure 3-4 — Inertia of South Australian power system



The reduced power system inertia seen in South Australia until late May 2013 is due to the shutdown of both units at Northern Power Station. Unit 1 was out of service from late April, and Unit 2 was out of service from late March. The combined inertia of these two generating units (3,000 MW.s) represents a material proportion of the typical power system inertia in South Australia.

Figure 3-5 — Inertia of mainland power system (QLD, NSW, VIC and SA combined)



3.3.2 Wind generation and inertia

Currently, AEMO assumes that inertia in the NEM is provided by conventional synchronous generators only. Modern wind turbines based on either doubly fed induction generators (type 3) or those using full rated power converters (type 4) are considered to provide no effective inertia to the power system, because the power electronics used in modern turbine designs effectively decouple the inertia of these turbines from the power system. Further information on these assumptions is provided in AEMO's earlier report on Wind Turbine Plant Capabilities.[22]

Older wind turbine designs based on fixed-speed induction generators do provide the power system with some limited inertia, due to their direct connection to the power system; however, this contribution is small, and is currently ignored in real-time operational calculations of power system inertia.

AEMO expects that the main effect of increased wind generation on power system inertia in the NEM will result from the economic displacement (by wind generation) of other forms of generation which provide inertia. Increased wind generation levels are likely to result in lower power system inertia, particularly during overnight periods of low demand and high wind generation, when fewer conventional synchronous generators are online.

Other future forms of renewable generation, such as utility-scale PV, are also expected to reduce power system inertia. However, in the absence of any storage, PV can only generate during daylight hours. The increase in power system demand during daylight hours is currently higher than the capacity of PV generation, meaning a net

[22] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Wind-Integration-Studies.

increase in synchronous generation is required during daylight hours compared to overnight minimum demand conditions.

3.3.3 Inertia and contingency FCAS requirements

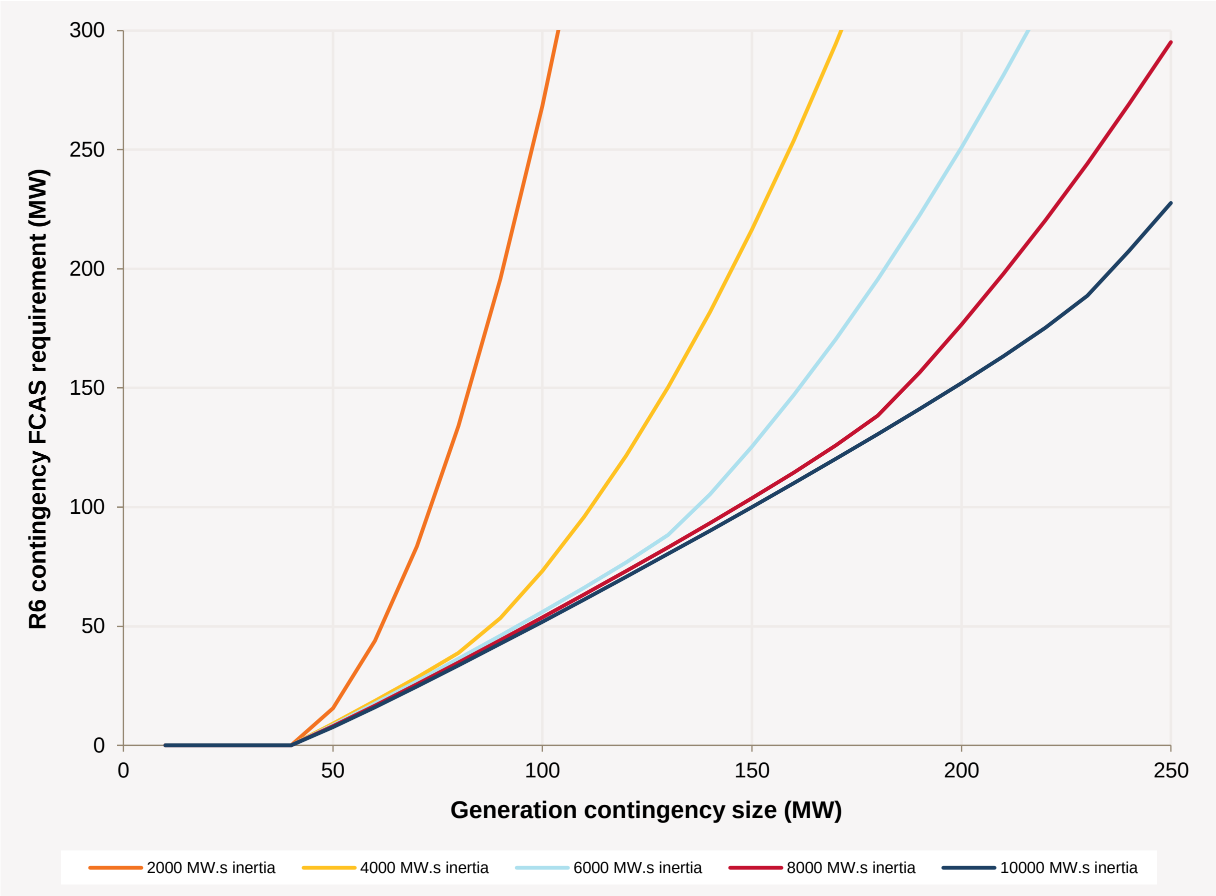
Under low power system inertia conditions, power system frequency will change faster following a given contingency. This then requires generators to respond more quickly to prevent the power system frequency from exceeding the limits outlined in the Frequency Operating Standards.

In practice, this means that larger quantities of contingency FCAS are required under low-inertia conditions. In particular, increased R6 (fast raise) and L6 (fast lower) services are required to maintain frequency within the requirements in the first six seconds following a contingency event.

As described, AEMO currently only considers inertia when calculating contingency FCAS requirements in Tasmania. Due to the physical characteristics of power systems, the required quantities of contingency FCAS increase non-linearly as inertia in Tasmania is reduced.

Figure 3-6 below shows Tasmanian R6 contingency FCAS requirements versus contingency size calculated for a particular operating condition in Tasmania.[23]

Figure 3-6 — Tasmanian R6 contingency FCAS requirements versus contingency size



[23] Tasmanian demand is 1,000 MW. Contingency is a single network event disconnecting two Gordon generators. Inertia is pre-contingent Tasmanian inertia.

To prevent excessive or infeasible requirements for contingency FCAS in Tasmania, AEMO currently limits the maximum generation contingency that can be managed through the use of contingency FCAS to 250 MW under all operating conditions. AEMO implements this limit using constraint equations in the central dispatch process. Under normal operating conditions the maximum generation contingency size is 144 MW. No limit is placed on load contingency size to limit L6 contingency FCAS requirements, as AEMO is not able to use the central dispatch process to manage Tasmanian load levels. However, AEMO may direct a load to reduce if necessary, for example under emergency power system conditions.

3.3.4 Inertia and rate of change of frequency

Under low power system inertia conditions, power system frequency will change faster following a given contingency, compared to higher power system inertia conditions.

The rate of change of frequency (RoCoF) experienced on a power system is highest immediately after a contingency event occurs. RoCoF gradually reduces as generator governors act to change power output in response to the change in power system frequency, through the provision of contingency FCAS. As power system frequency changes, frequency-dependent load relief[24] can also act to reduce the initial instantaneous RoCoF by reducing power system load as frequency falls, or increasing load as frequency increases.

Importantly, there is a time lag before any response to changing power system frequency will be seen from generator governors or other control systems. Depending on governor and control behaviours, this period can last from 0.25 to 1 second, or even longer after a disturbance.

During this initial period the only factors which determine RoCoF are contingency size and power system inertia levels; increasing contingency FCAS levels will not assist in managing RoCoF during this initial period. This issue is particularly important in Tasmania with its large proportion of hydro generation, which has relatively slow acting governors.

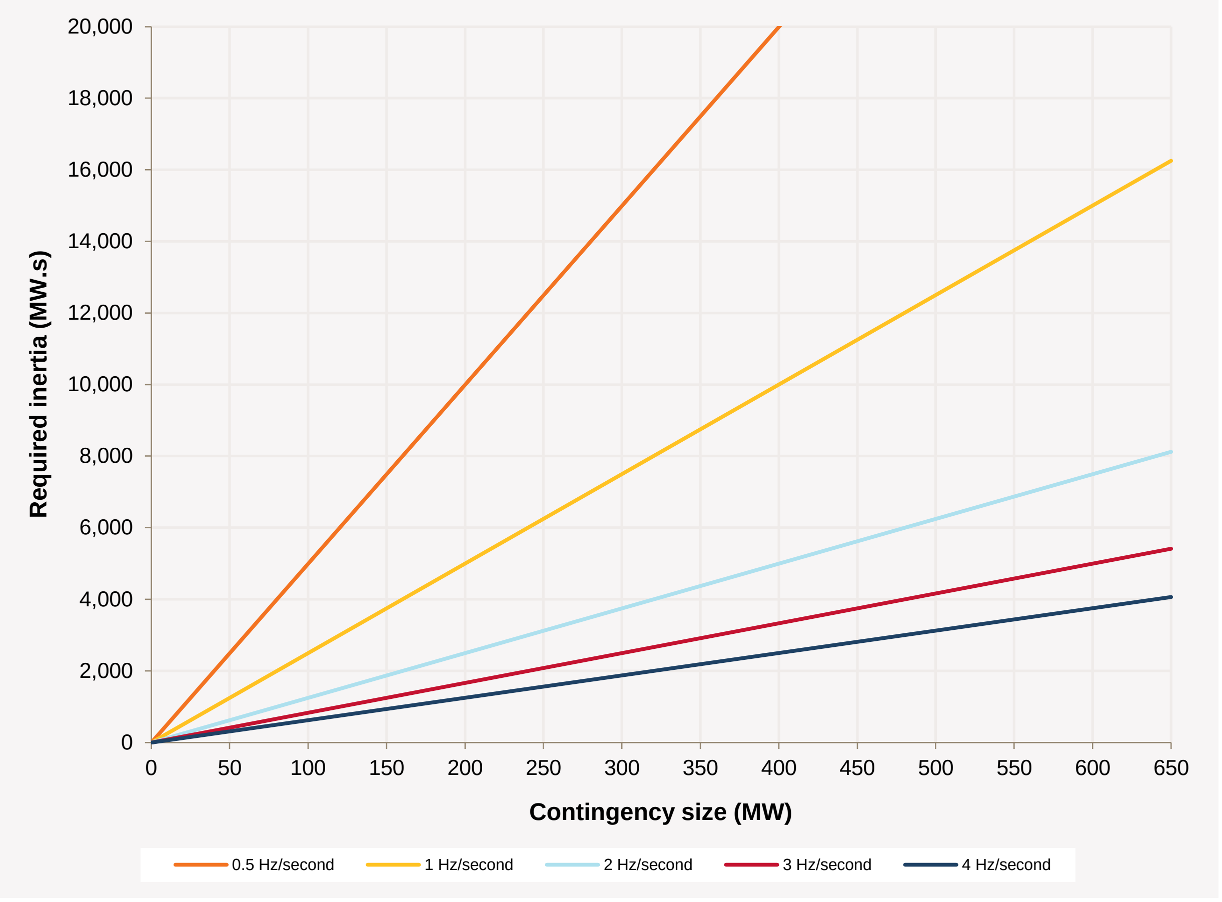
High RoCoF is not currently an issue on the mainland due to the high levels of inertia relative to contingency size; however, RoCoF is already considered in power system studies in Tasmania, due to lower levels of power system inertia relative to contingency size.

A review of historical power system inertia levels in South Australia suggests that RoCoF should also be considered there under conditions where the South Australian power system can become separated from the NEM. This may occur either due to a single credible contingency, or where non-credible contingency events resulting in separation from the NEM are being considered. At present, acceptable RoCoF limits in South Australia are not known, and AEMO is currently seeking more information on a range of possible limits.

Figure 3-7 below shows the relationship between power system inertia, contingency size, and initial instantaneous RoCoF. It indicates the initial maximum RoCoF that may be experienced following a contingency, prior to any generator governor or other control action, and prior to any frequency-dependent load relief.

[24] Mainland load levels are assumed to increase or decrease by 1.5% for each 1% change in frequency above or below the nominal 50 Hz respectively. In Tasmania the assumed load relief factor is 1.0% for each 1% change in frequency.

Figure 3-7 — Instantaneous RoCoF versus contingency size and power system inertia level



Protection relays designed to detect high RoCoF may be installed as part of control schemes to manage non-credible contingency events on the power system, or to prevent unwanted islanding of load with local generation. RoCoF relays are known to be installed at some locations within the NEM to detect conditions where a power system contingency results in a large load–generation imbalance, requiring rapid action to prevent plant damage, to manage safety concerns, or to minimise disruption to the power system.

For example, very high RoCoF may occur if a part of the power system with high levels of generation compared to load is separated from the rest of the power system, resulting in a rapid increase in frequency in the portion of the network remaining connected to that generation. Some under-frequency load shedding schemes in Tasmania consider RoCoF, in addition to absolute power system frequency, to ensure correct performance of these schemes.

Schedule 5.2.5.3 of the National Electricity Rules (NER)[25] specifies minimum and automatic access standards with respect to the level of RoCoF that new generation over 5 MW must withstand while being capable of continuous uninterrupted operation. Currently, the automatic access standard is that the generator must withstand a RoCoF of 4 Hz per second for a period of 0.25 seconds. The minimum access standard is 1 Hz per second, for a period of one second.

[25] AEMC. Available: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html.

3.3.5 Inertia and transient stability

The impact of inertia on frequency control relates to the total inertia of the power system. Under normal NEM operating conditions, the relevant inertia is the summated inertia of all mainland regions, or the inertia within Tasmania.

Inertia within individual regions, or sub-regions, of the power system is also important when considering the transient stability of the power system. AEMO determines transient stability limits by considering the ability of generation located within a specific NEM region or sub-region to remain in synchronism with other NEM generation following a large disturbance.

Transient stability limits are described using equations that relate various power system quantities such as power flows between regions, demand levels, generation output at various locations, and power system inertia levels. When determining transient stability limits of the power system, the inertia of generation located within a particular NEM region or sub-region is particularly important. This is evident in the formulation of existing limit equations for describing transient stability limits in the NEM, which often contain significant terms for the inertia of online generation located within specific NEM regions or sub-regions.

Inertia terms in transient stability limit equations can be either positive or negative, depending on the nature of the transient stability phenomena being studied. This means changes in inertia levels can increase or decrease transient stability limits. As a result, AEMO cannot generally predict the effect of increasing wind generation and reduced power system inertia levels on transient stability limits in the NEM; this must be considered case-by-case.

The effects of increased wind generation on NEM transient stability limits more generally are considered in Section 5.2 of this report.

3.4 Basslink

The Basslink HVDC Interconnector connects Tasmania and the mainland. It is rated at approximately 480 MW power transfer from Victoria to Tasmania, and 600 MW from Tasmania to Victoria.

3.4.1 Basslink Frequency Controller

Basslink is fitted with a control scheme called the Basslink Frequency Controller. This scheme compares the power system frequencies in Tasmania and on the mainland, and rapidly adjusts the power transfer level on Basslink to correct any frequency differences detected.

Because Tasmania and the mainland have different Frequency Operating Standards following contingency events, the Basslink Frequency Controller does not attempt to exactly equalise the frequency in Tasmania and the mainland; rather, it attempts to ensure a “proportional” deviation in frequency between the two regions with respect to the different Frequency Operating Standards.

This scheme is particularly important for power system frequency control in Tasmania, which typically experiences larger variations than the mainland. Basslink Frequency Controller action can result in large and rapid changes in Basslink flow to correct frequency differences, particularly following large load or generator disconnections in Tasmania.

The Basslink Frequency Controller provides a much faster response to frequency changes than FCAS provided by from generator governors[26], and studies by AEMO and Transend suggest that this difference needs to be considered when assessing contingency FCAS requirements in Tasmania.

The two other HVDC links in the NEM (the Murraylink Interconnector between Victoria and South Australia, and the Directlink Interconnector between New South Wales and Queensland) are not fitted with frequency controllers. Both will operate with constant active power flows despite frequency differences between the two ends of the links.

[26] The Basslink Frequency Controller will respond within several hundred milliseconds, while hydro governors can take 1-2 seconds to provide an appreciable response.

Both these links normally operate in parallel with an AC interconnector, so there is normally no frequency difference between the two ends.

3.4.2 Basslink FCAS transfers

The Basslink Frequency Controller allows the use of mainland generators to manage Tasmanian frequency via Basslink, and vice-versa. It effectively allows the “transfer” of both regulation and contingency FCAS between the mainland and Tasmania. This allows a larger pool of generators to provide FCAS, and facilitates competition for FCAS provision between these two areas. It is not uncommon to see periods where some Tasmanian FCAS requirements are sourced entirely from the mainland via Basslink, or vice-versa.

Basslink’s ability to transfer FCAS between the mainland and Tasmania can be limited when Basslink is operating near its power transfer limits, where transfer of FCAS would require operation beyond the relevant limit.

To provide for FCAS transfers, power transfers on Basslink may be adjusted through the central dispatch process, to ensure there is sufficient “headroom” on Basslink between its power transfer limits and its initial operating point.

These adjustments will occur automatically when AEMO determine this to be the overall optimum dispatch solution, considering the relative value of both FCAS and energy transfers between the mainland and Tasmania on Basslink.

Basslink requires a several-minute pause in operation when reversing power transfer direction through zero, and it is unable to transfer FCAS between the mainland and Tasmania during these flow reversal periods. Basslink cannot transfer FCAS if the Basslink Frequency Controller is out of service for any reason; that said, it is normally left in service at all times.

Basslink’s ability to transfer FCAS must be considered when determining FCAS requirements in Tasmania and the mainland, and where these requirements can be sourced from. When Basslink is unable to transfer FCAS, Tasmania must obtain all FCAS requirements from Tasmanian generators. This can be challenging during periods when few Tasmanian generators are offering to provide FCAS.

Increased levels of wind generation in Tasmania may exacerbate the issue of procuring sufficient FCAS in Tasmania, either during Basslink flow reversals, or when Basslink is operating at or near its limits.

Wind generation may displace other generation that would otherwise provide FCAS during these periods, increase the requirement for contingency FCAS during these periods due to lower power system inertia, and increase the effective contingency size due to the fault ride through behaviour of wind generation.[27]

3.5 Control schemes and frequency control

Contingency FCAS is the primary method used in the NEM to manage power system frequency following single credible contingency events resulting in unplanned load or generation disconnection. However, contingency FCAS alone would not be able to manage power system frequency within the Frequency Operating Standards requirements following all possible contingency events. Several control schemes are installed in the NEM to control power system frequency, particularly following multiple, non-credible, or very large credible contingency events.

3.5.1 Under-frequency load shedding

Under-frequency load shedding (UFLS) schemes are installed throughout the NEM. These are designed to rapidly disconnect selected load from the power system once frequency falls below pre-defined thresholds. This helps to correct large supply–demand imbalances, and prevents total collapse of the power system.

[27] Wind turbines can rapidly reduce active power output immediately following a disturbance as part of their fault ride through behaviour. This is described further in AEMO’s Wind Turbine Plant Capabilities Report available at http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Wind-Integration-Studies.

UFLS schemes are only expected to operate following non-credible contingency events such as simultaneous disconnection of multiple generators from the power system, or other operating conditions where contingency FCAS alone would not be sufficient to manage power system frequency within requirements.

The conditions that trigger load shedding by a UFLS scheme must be carefully determined to ensure that sufficient load is shed to arrest the fall in frequency, while ensuring ongoing stable power system operation.

On the mainland, UFLS schemes only consider frequency when determining whether to disconnect load. In Tasmania, UFLS schemes monitor both frequency and the rate of change of frequency (RoCoF). This is required to correctly operate Tasmanian UFLS schemes because of the lower inertia and potentially faster RoCoF that can occur there.

3.5.2 Over-frequency generator shedding

An over-frequency generation shedding (OFGS) scheme is currently installed in Tasmania. This scheme is designed to rapidly disconnect selected generation from the power system once frequency rises above pre-defined thresholds, to manage non-credible contingency events resulting in a large excess of generation over load.

Similar schemes are currently being investigated for installation in South Australia and Queensland, for conditions where the AC interconnection with Victoria or New South Wales respectively is suddenly disconnected under conditions of high power transfer due to non-credible contingency events.

These events are not managed using contingency FCAS, as loss of these AC interconnections is not normally considered a credible contingency event. However, such events are physically possible, and the Frequency Operating Standards provide target frequency operating ranges for non-credible, multiple power system contingency events, which may require the use of such control schemes.

As with UFLS schemes, the conditions that trigger generator tripping by an OFGS scheme must be carefully determined to ensure that sufficient generation is disconnected to arrest a rapid rise in frequency, while ensuring ongoing stable operation of the power system.

3.5.3 Frequency Control Special Protection Scheme

With a power transfer capacity of up to 600 MW, Basslink is very large relative to the size of the Tasmanian power system. Frequency in Tasmania could not be maintained within requirements following disconnection of Basslink at these very high power transfer levels using only contingency FCAS.

For comparison, the largest Tasmanian load contingency is typically around 210 MW, and the largest effective loss of generation for a single contingency in Tasmania is normally around 144 MW; this will rise to around 170 MW with full service of the Musselroe Wind Farm in late-2013.

The Frequency Control Special Protection Scheme (FCSPS) is used in Tasmania to manage Tasmanian frequency following unplanned disconnection of Basslink at high power transfer levels. The FCSPS rapidly disconnects either industrial load or generators in Tasmania following disconnection of Basslink at high power transfers, to rapidly correct the resulting load–generation imbalance. Basslink transfers are significantly restricted if the FCSPS is unavailable, due to the need to manage Tasmanian frequency following trip of Basslink with contingency FCAS alone.

Under conditions of high power transfer from Tasmania to Victoria, the FCSPS trips sufficient generation in Tasmania to almost exactly balance the lost power transfer on Basslink, leaving virtually no residual load–generation imbalance. Due to this action, there is no requirement for contingency lower FCAS within Tasmania for loss of Basslink during transfers from Tasmania to Victoria.

Under conditions of high Basslink transfer from Victoria to Tasmania, the FCSPS rapidly trips industrial load in Tasmania following disconnection of Basslink; this restores the load–generation balance in Tasmania. The FCSPS currently trips sufficient load in Tasmania to balance the lost supply from Basslink, minus approximately 80–100 MW. This can create a residual requirement for contingency raise FCAS, which must be sourced locally.

The FCSPS provides an example of using a control scheme to reduce the effective size of a load or generation contingency to a much smaller residual value by rapidly either partially or fully correcting the supply–demand imbalance. This either removes, or significantly reduces, the subsequent need for contingency FCAS to manage power system frequency within requirements.

With increased levels of wind generation, similar control schemes could be considered to minimise, or remove entirely, the need for contingency FCAS to manage power system frequency following certain contingencies—particularly larger or non-credible events.

Experience in Tasmania suggests the design of such control schemes must carefully consider such issues as speed and security of operation, and the transient behaviour of the power system before and after the control scheme takes action to trip either generation or load following a contingency event.

3.5.4 Tamar Valley Generation Control Scheme

The Tamar Valley combined cycle gas turbine (CCGT) in Tasmania, commissioned in 2009, has a total rated capacity of 208 MW, all of which can be disconnected following a single credible contingency event. This is larger than the 144 MW maximum generation contingency size historically seen in Tasmania, and described in Tasmania's Frequency Operating Standards. To allow connection of a generator of this size in Tasmania, a generation control scheme (GCS) was installed as part of the unit's commissioning.

This GCS acts to rapidly disconnect sufficient industrial load in Tasmania following disconnection of the Tamar Valley CCGT to reduce the effective load–generation imbalance to below 144 MW, which was the largest single generating unit in service at the time of commissioning. Installing this GCS minimised the impact of the Tamar Valley CCGT on contingency FCAS requirements in Tasmania, and was a Tasmanian Frequency Operating Standards requirement.

3.6 Frequency control and increasing wind generation

The main way in which wind generation can affect NEM frequency control is economic displacement of synchronous generation. Due to the low marginal cost of wind generation compared to most other forms of generation, AEMO expects wind generation will remain at or near the bottom of the economic merit order, running at full output wherever possible, subject only to the available wind and any network limitations.

Increased wind generation has the potential to both increase FCAS requirements, and simultaneously reduce the supply of available FCAS by displacing generation that would otherwise supply FCAS. Both of these effects would be most material during periods of low demand and high wind generation output.

For the purposes of this study AEMO assumed that all new wind generation will choose not to participate in FCAS markets, and will provide no effective inertia to the power system. AEMO assumed that wind generation will not increase or decrease its active power output in response to changing power system frequency within the normal frequency operating band, and will not provide any increase in output in response to larger falls in system frequency following generation contingency events. AEMO considers these to be business-as-usual assumptions.

Table 3-2 indicates the number of separate generating units located within each NEM region registered to provide AEMO with FCAS. This table indicates there are relatively few units located in South Australia, and examination of the underlying data (available on AEMO's website[28]) shows that all R6 and L6 contingency FCAS in South Australia are provided by generating units located at only four power stations. If some or all of these units were economically displaced by wind generation, there would be reduced or no source of these key fast contingency FCAS in South Australia.

[28] AEMO. Available: http://www.aemo.com.au/Electricity/Registration.

Table 3-2 — Number of separate generating units registered to provide FCAS

	Lower 5-min (L5)	Lower 60-sec (L60)	Lower 6-sec (L6)	Lower reg (Lreg)	Raise 5-min (R5)	Raise 60-sec (R60)	Raise 6-sec (R6)	Raise reg (Rreg)
QLD	19	22	21	24	24	26	23	24
NSW	24	23	22	23	30	30	23	23
VIC	15	23	31	18	19	24	32	18
SA	4	11	11	11	4	9	11	11
TAS	18	18	19	17	17	17	17	17

Table 3-3 indicates the sum of the maximum potential FCAS capabilities registered with AEMO for various requirements. These are the maximum possible capabilities registered; the actual capability that can be offered to AEMO at any time depends on the current operating point of the generating units.

There is significant overlap between the data for these various FCAS requirements, as the same megawatt capability of a generator may be registered for a range of different FCAS requirements. A single power system load may also be registered to provide a range of different raise FCAS requirements.

Table 3-3 indicates that the maximum quantities of FCAS available locally within South Australia are relatively small in comparison to other regions.

Table 3-3 — Total quantity of FCAS capabilities registered with AEMO (MW)

	Lower 5-min (L5)	Lower 60-sec (L60)	Lower 6-sec (L6)	Lower reg (Lreg)	Raise 5-min (R5)	Raise 60-sec (R60)	Raise 6-sec (R6)	Raise reg (Rreg)
QLD	3,543	993	734	1,074	1,647	2,059	1,210	1,046
NSW	2,424	2,476	1,367	2,000	3,732	3,787	1,674	2,000
VIC	1,870	2,463	1,895	1,628	2,106	2,119	1,694	1,628
SA	200	364	178	320	200	318	172	380
TAS	2,171	2,373	614	2,141	2,071	1,786	358	2,141

3.6.1 Regulation FCAS

Under normal operating conditions, the requirements for regulation FCAS in the NEM are fixed. There is a 120 MW and 130 MW global requirement for lower and raise regulation FCAS respectively, and a 50 MW raise and 50 MW lower regulation FCAS requirement for Tasmania.

Based on operational experience, these quantities have historically been empirically determined as sufficient under normal operating conditions to maintain power system frequency on the mainland and in Tasmania within the normal operating range at least 99% of the time, as specified in the Frequency Operating Standards.

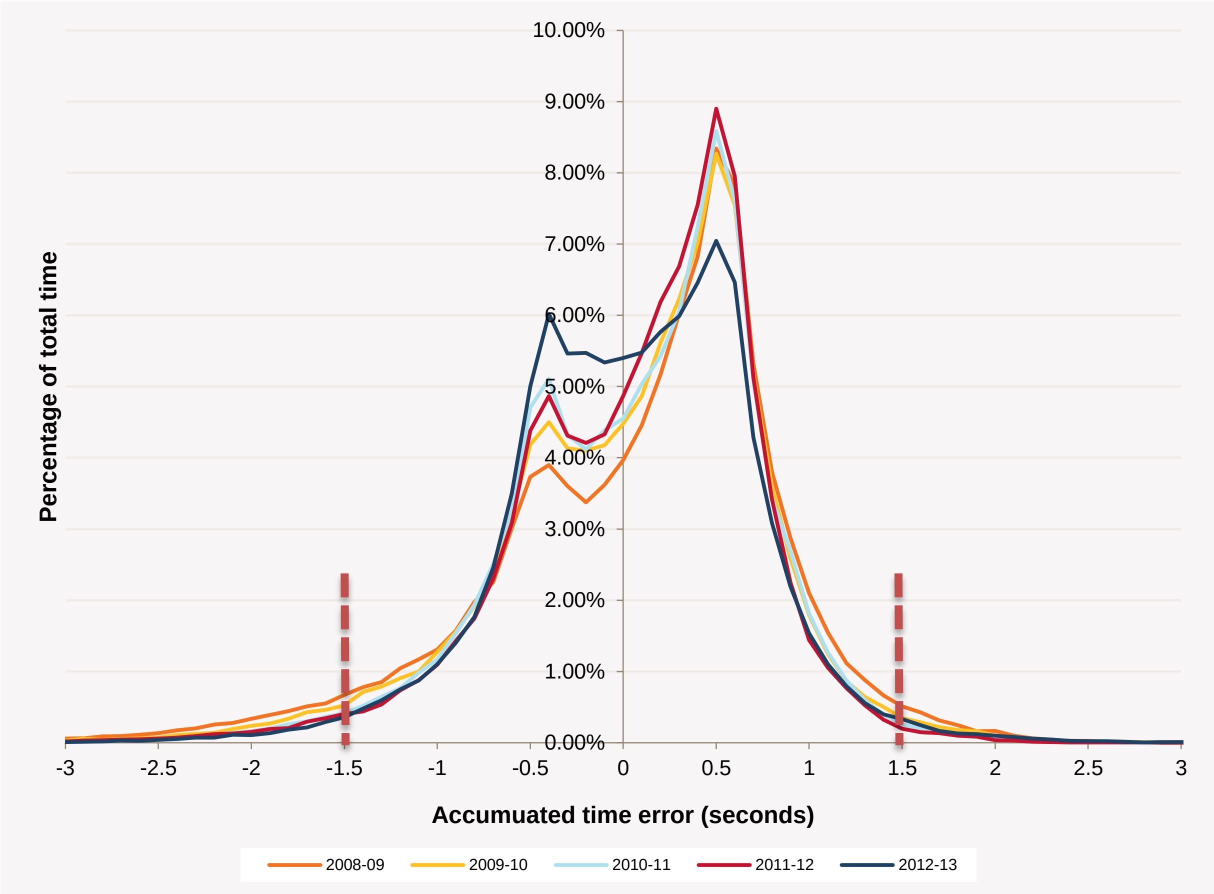
Global regulation FCAS requirements are automatically increased by AEMO when the accumulated time error[29] derived from the measured mainland frequency exceeds +/- 1.5 seconds. This approach of automatically adjusting global regulation FCAS requirements based on accumulated time error was developed empirically rather than

[29] The time difference between a perfectly accurate clock and one driven by a synchronous motor operated on NEM frequency.

analytically, and has to date been observed to allow very good compliance with the Frequency Operating Standard requirements.

The distribution of actual measured accumulated time error for the mainland over the last five years is shown below in Figure 3-8.

Figure 3-8 — Distribution of mainland accumulated time error



Installed wind generation capacity in the NEM increased from around 1,100 MW to 2,500 MW in the five-year period covered by this data. Figure 3-8 does not indicate any increase in the accumulated time error on the mainland during this period, and in fact shows a slight reduction.

As described earlier, the key factors that determine the requirement for regulation FCAS are as follows:

- Normal frequency ranges specified in the Frequency Operating Standards.
- Aggregate error in the five-minute-ahead forecasts of load and generation.
- Performance of generation in meeting their dispatch targets.

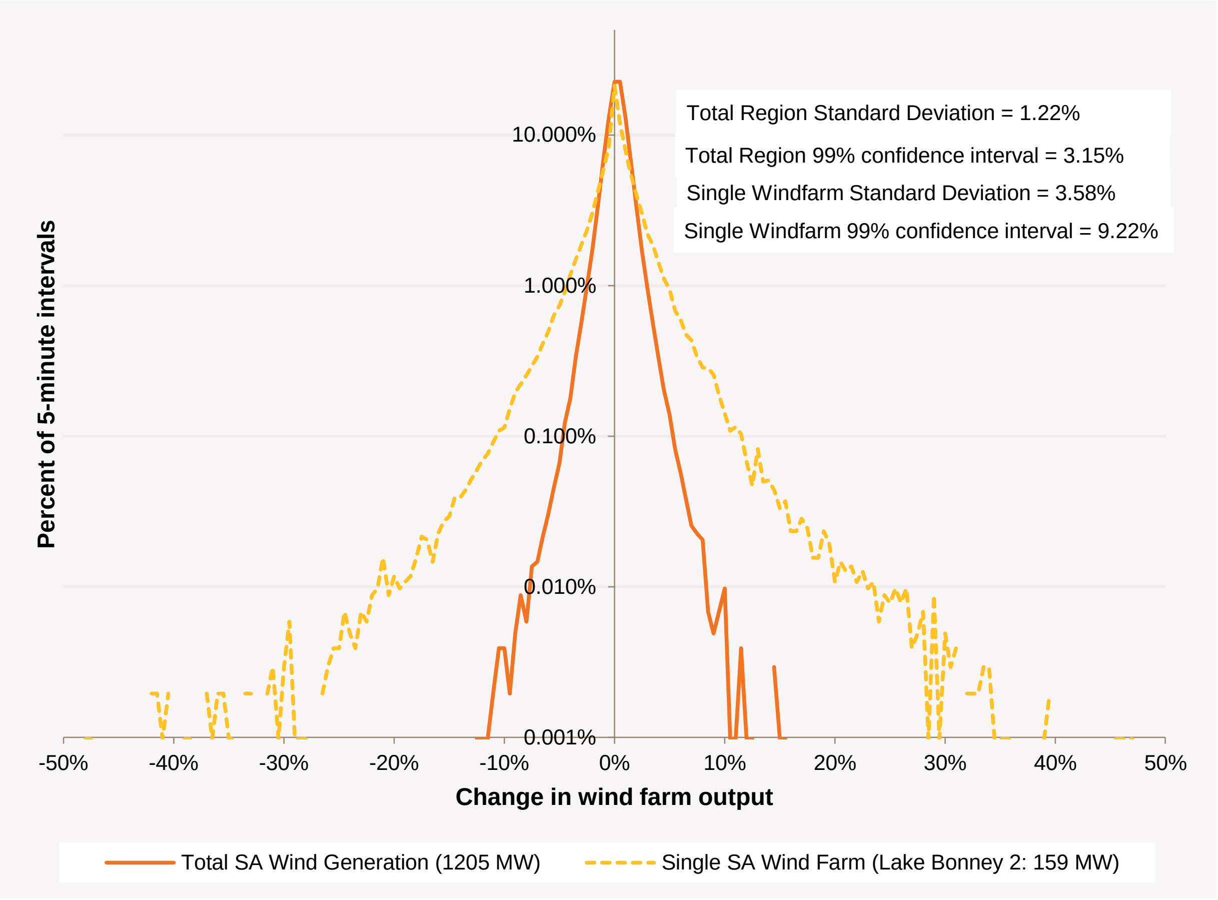
Wind generation is variable, and its output can rapidly change due to changing wind conditions in a way that cannot be fully predicted. Assuming that there is no change to the Frequency Operating Standards, no change in the performance of existing five-minute-ahead demand forecasts, and no change to generation performance in meeting central dispatch targets, the key issue for frequency regulation in the NEM with increased wind generation appears to be the accuracy of five-minute-ahead wind generation forecasts, and how this will in turn determine the aggregate error in forecasts of the load–generation balance. Increased errors in the aggregate five-minute-ahead wind generation and demand forecasts will increase the requirement for regulation FCAS to maintain power system frequency within requirements.

Assuming that the accuracy of existing NEM wind forecasting systems remains unchanged when expressed as a percentage of installed wind generation capacity, then the issue becomes how large the expected five-minute changes in wind generation might be as wind generation increases, as well as how these changes correlate with errors in forecasting demand.

Information on historical changes in wind generation, both for individual wind farms and aggregated wind generation over larger areas, provides some guidance to the likely errors in five-minute-ahead wind generation forecasts as levels of wind generation increase. Figure 3-9 to Figure 3-12 below show the historically recorded five-minute change in wind generation output as a percentage of the entire installed capacity in Victoria, South Australia, Tasmania, and across the entire NEM for the 12-month period from 1 April 2012 to 1 April 2013.

Also included in Figure 3-9 and Figure 3-10 are the historically recorded five-minute changes for a selected single wind farm located in Victoria and South Australia respectively. Tasmania only had one operating wind farm at the time this data was collected. These figures show the standard deviation of this five-minute change in output data, and the 99% confidence level for these changes.[30]

Figure 3-9 — Five-minute change in South Australian wind generation in 2012–13



[30] This is 2.58 standard deviations, assuming the data is normally distributed.

Figure 3-10 — Five-minute change in Victorian wind generation in 2012–13

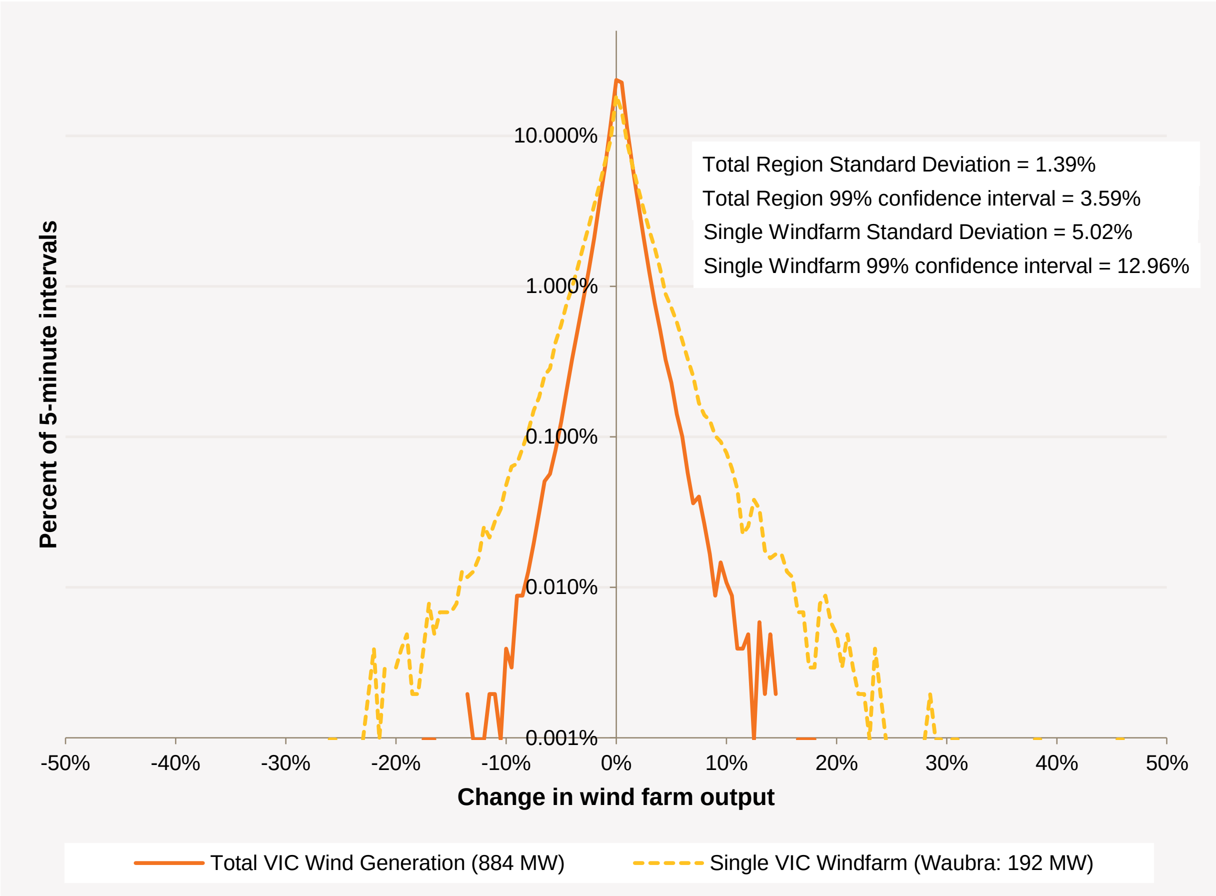


Figure 3-11 — Five-minute change in Tasmanian wind generation in 2012–13

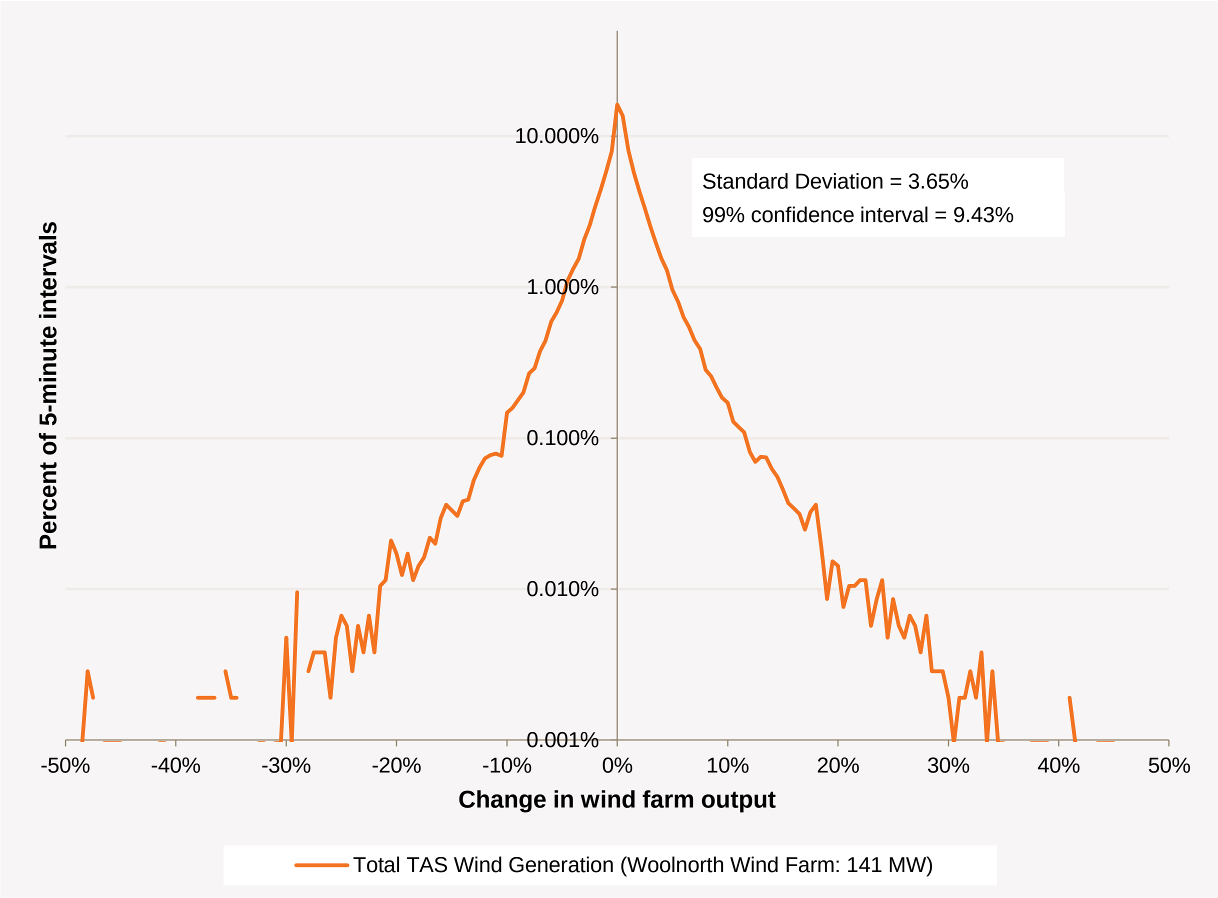
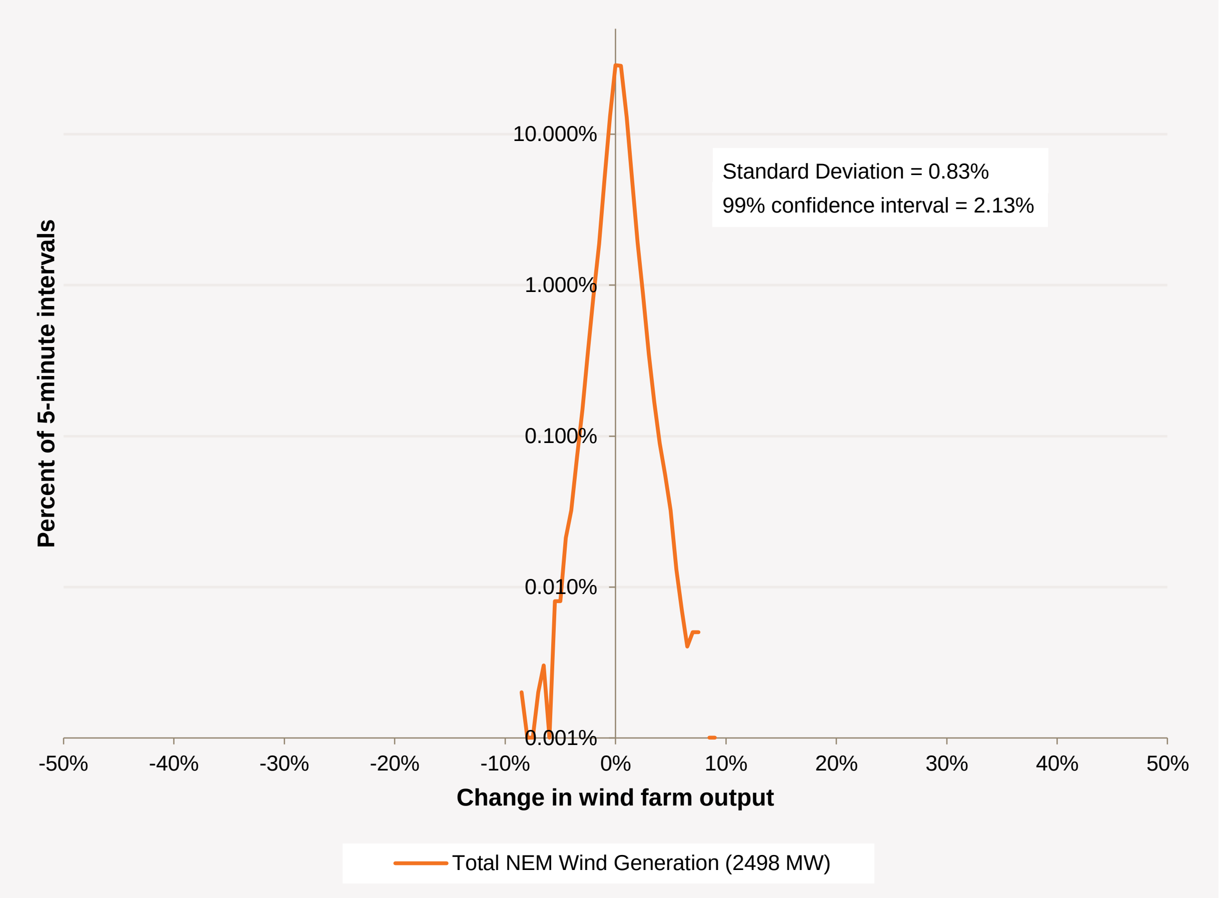


Figure 3-12 — Five-minute change in NEM wind generation in 2012–13

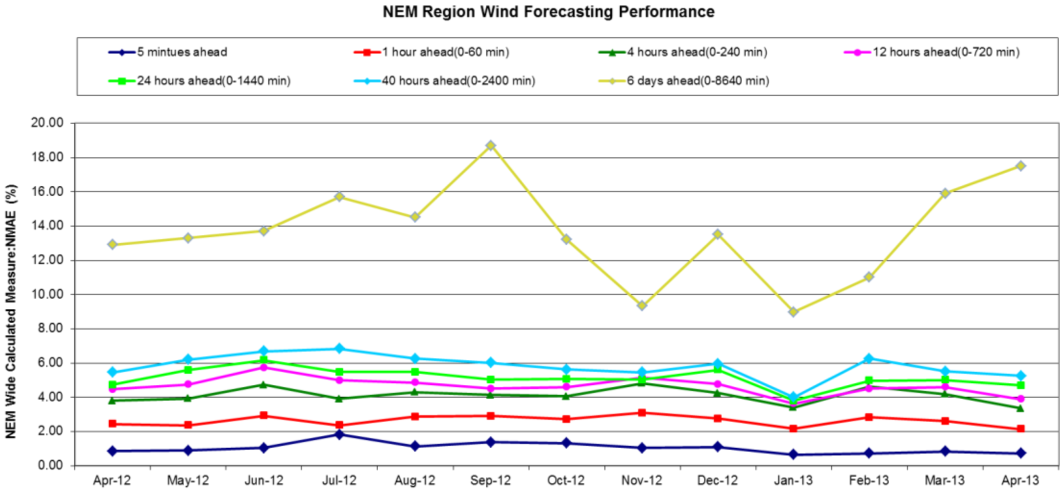


A key point evident in these figures is that the aggregate wind generation output, both within a region and across the NEM, changes less (as a percentage of installed capacity) over a five-minute period than the output of any single wind farm. The standard deviation of the distribution of five-minute changes becomes smaller as wind generation capacity is installed over a larger geographical area.

These figures show the actual measured change in output. The important factor in determining the potential impact on regulation FCAS of these changes in wind farm output is the likely error in forecasting these changes in output five minutes in the future.

The Australian Wind Energy Forecasting System (AWEFS), which AEMO uses to forecast the future output of wind generation, has a five-minute-ahead normalised mean absolute error target of 2.4%. Figure 3-13 shows the actual monthly normalised mean absolute error performance of the AWEFS for range of forecasting timeframes between April 2012 and April 2013.

Figure 3-13 — NEM wind generation forecast errors from AWEFS



	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13	Feb-13	Mar-13	Apr-13
5 mintues ahead	0.84	0.89	1.04	1.81	1.13	1.37	1.31	1.03	1.09	0.64	0.73	0.83	0.72
1 hour ahead(0-60 min)	2.43	2.35	2.91	2.36	2.87	2.90	2.72	3.09	2.75	2.16	2.82	2.61	2.13
4 hours ahead(0-240 min)	3.79	3.93	4.72	3.91	4.29	4.12	4.05	4.81	4.24	3.41	4.61	4.19	3.35
12 hours ahead(0-720 min)	4.46	4.74	5.73	4.98	4.86	4.51	4.59	5.15	4.76	3.62	4.51	4.59	3.88
24 hours ahead(0-1440 min)	4.73	5.59	6.16	5.47	5.47	5.03	5.06	5.03	5.61	3.79	4.97	5.00	4.69
40 hours ahead(0-2400 min)	5.46	6.19	6.69	6.83	6.25	6.02	5.62	5.45	5.96	3.99	6.25	5.51	5.24
6 days ahead(0-8640 min)	12.90	13.30	13.70	15.70	14.50	18.70	13.20	9.33	13.50	8.97	11.00	15.90	17.50

AEMO's 2012 National Transmission Network Development Plan (NTNDP) projected a total 2020 NEM wind generation capacity of approximately 11,500 MW.

Assuming also that this 11,500 MW of NEM wind generation continues to exhibit the five-minute variability characteristic shown for the NEM today in Figure 3-12, then the 99% confidence level for a five-minute change in NEM installed wind generation by 2020 would remain at 2.13% (245 MW).

This assumption would seem plausible, if wind generation in the NEM in 2020 continued—at least on the mainland—to be as widely geographically distributed as it is today.

If this five-minute change in output was completely un-forecast (i.e., it appeared entirely as an error in the forecast of generation capacity) and it also represented the entire aggregate load–generation error that needed to be managed through the use of regulation FCAS, it would exceed currently available levels of five-minute regulation FCAS, degrading regulation of frequency in the NEM. However, this expected change in wind generation would be less than this 99% of the time.

These levels of generation change are still below historic levels of regulation FCAS (250 MW) that have been used in the NEM, and these five-minute changes in wind generation also need to be considered alongside load forecast errors, as these two errors can potentially cancel out, or be additive. Some or most of this change may also potentially be forecast by the AWEFS system, further reducing the impact on regulation FCAS requirements.

Examining the historical distribution of five-minute changes in wind generation output suggests that the impact of 2020 levels of wind generation on NEM frequency regulation is likely to remain manageable within the existing frequency regulation arrangements, given the five-minute balancing arrangements used for frequency control in the NEM.

However, it may be necessary to increase both the normal quantities of regulation FCAS used for control of power system frequency, and the maximum quantities that are obtained in response to increased levels of accumulated time error. Given the large available supply and low cost of obtaining regulation FCAS, AEMO expects these potentially increased requirements could be managed within existing arrangements.

As increased levels of wind generation are installed and commissioned progressively to 2020, it should also be possible to observe any progressive degradation of NEM mainland frequency regulation, and respond by incrementally increasing the normal regulation FCAS requirements to compensate as required.

3.6.2 Tasmanian frequency regulation

The effect of the projected wind generation increase in Tasmania on frequency regulation is likely to be material, due to the expected amount of wind generation installed by 2020 relative to the load size of the Tasmanian power system, and the localised arrangements required within Tasmania for frequency control.

Increasing the geographic distribution of wind generation within Tasmania is likely to reduce the change in wind generation over five minutes expressed as a percentage of installed capacity (as shown in Figure 3-11); however, the increase in total installed wind generation capacity can increase the un-forecasted absolute change in megawatt output over five minutes, which will ultimately drive the requirement for regulation FCAS in Tasmania.

How these two opposing factors—geographic distribution and total capacity—will interact in Tasmania to produce an overall effect on regulation FCAS requirements is not clear at this time. As additional wind generation is installed in Tasmania, it may become necessary to increase Tasmanian regulation FCAS requirements above the current level of 50 MW to ensure Tasmanian frequency regulation continues to function as required. Automatic arrangements could be readily established to do this if required, similar to those already used on the mainland.

As shown in Table 3-3, there are significant quantities of regulation FCAS registered within Tasmania, and if required, regulation FCAS can also be obtained in Tasmania from the mainland under most operating conditions.

3.6.3 Large changes in wind generation

Under high wind speed or ambient temperature conditions, wind generation can shut down to protect wind turbines from damage. These shutdowns normally occur at the individual wind turbine level, rather than the entire wind farm, and have been observed to occur in a staggered manner over periods of at least several minutes. They do not result in instant disconnection of an entire wind farm from the power system.

Depending on how fast they occur, these rapid shutdown events fall somewhere between the NEM regulation and contingency FCAS arrangements. Similar rapid increases in output from wind generation have also been noted historically in response to rapidly increasing wind speed conditions.

If they were not forecast, slower events that occur over a number of five-minute dispatch intervals would effectively appear as generation capacity forecasting errors in the central dispatch process. These could be managed through the use of regulation FCAS if they were slow enough or small enough. If slower shutdown or increase events could be at least partially captured in the five-minute-ahead wind capacity forecasts, this would further minimise their impact.

For more rapid, or larger events, the NEM already holds sufficient contingency FCAS to manage sudden disconnection of the largest conventional generators connected to the mainland power system; typically in the range of 600–700 MW. Rapid wind generation shutdown events would effectively become generation contingency events, to be managed with contingency FCAS to ensure frequency remained within the Frequency Operating Standard requirements.

As long as the total size of any rapid change in generation event occurring within a five-minute period was smaller than the size of the largest single conventional generator trip in the NEM, such events would not result in power system frequency breaching the current limits for contingency events.

However, these events may present specific challenges in both Tasmania and South Australia, which currently have a maximum effective generation contingency size of around 144 MW and 280 MW respectively. Rapid generation change events in these regions could effectively result in a new maximum generation contingency event within the region. This could also occur in other NEM regions with installation of sufficient wind generation capacity, depending on the geographic spread of the wind generation.

Rapid generation changes in Tasmania and South Australia could result in high loading on NEM interconnectors supplying these regions, due to the provision of either regulation or contingency FCAS from generators in adjacent regions to manage a rapid generation change event.

Table 3-4 below provides information on installation capacity and the maximum historically recorded changes in output from wind generation installed in South Australia, for both sub-regions within South Australia, and as a region total. This information was obtained from AEMO's 2012 South Australian Wind Study Report[31], which uses different geographic groupings of South Australian wind generation than those used in AEMO's NTNDP and in this report.

Table 3-4 suggests that these rapid five-minute changes in output become a smaller percentage of installed capacity as the geographic diversity increases. These large generation reduction events have historically been around the same size as the largest generating unit currently installed in South Australia, and the rapid increase events are already large relative to typical variation in South Australian demand.

Table 3-4 — Maximum recorded five-minute change in South Australian wind generation (MW)

	Mid-north region	South-east region	Coastal Peninsula region	Total South Australia
Existing installed capacity	618	325	192	1,205
Maximum 5-minute increase	275 (44%)	122 (38%)	131 (68%)	279 (23%)
Maximum 5-minute decrease	277 (45%)	140 (43%)	131 (68%)	294 (24%)

If the percentage change of total regional capacity is assumed to remain constant as the expected installed wind generation in South Australia increases to around 2,500 MW by 2020, this table suggests changes of up to 600 MW (24%) in five-minute wind generation may be seen. This 24% change would represent the extreme outliers in a distribution of five-minute wind generation changes, and is well beyond the 99% confidence interval currently seen for five-minute changes in wind generation in South Australia, as shown in Figure 3-9.

The upgrade of the Heywood Interconnector[32], which this report assumes to be in service by 2020, may assist in managing these events in South Australia by increasing the ability to source FCAS from Victoria following rapid changes in the output of wind generation in South Australia under conditions where the interconnector is not operating at full capability.

These events also have the potential to result in voltage control, thermal loading, or other local network issues, due to the large change in network loading occurring over short time periods.

3.6.4 Managing large generation changes

The impact of large five-minute changes in wind generation output on power system operation could be minimised if these changes could be forecast using existing wind forecasting systems.

The wind turbine models used in AEMO's wind energy forecasting system (AWEFS) do currently include functionality for modelling rapid shutdown of wind turbines due to forecast high wind speeds. However, experience to date has shown that the accuracy of future wind speed forecasts is not yet sufficient to identify with a high degree of confidence when such shutdown events due to high wind speed may occur. The wind turbine models used do no currently model future turbine shutdown due to high temperature events.

Alternately, AEMO could potentially manage these events by first identifying periods when rapid shutdown or increases of generation are possible, or considered credible. This could be during forecast storm fronts, or during periods of very high ambient temperature.

[31] AEMO. Available: http://aemo.com.au/Electricity/Planning/South-Australian-Advisory-Functions/Wind-Study-Report.

[32] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Regulatory-Investment-Tests-for-Transmission-RITTs/Heywood-Interconnector-RIT-T.

It would be necessary to identify both the location and the megawatt capacity of generation that may be subject to rapid shutdown or increase. During these periods special operating arrangements could be put in place to ensure secure power system operation.

Given the significance of both the potential consequences of these rapid shutdown or increase events, and the impacts of any action to secure the power system against them, it would be important to identify periods when these may occur with a fairly high degree of confidence.

AEMO would need to identify them sufficiently in advance to allow the power system to be adjusted or reconfigured as required. Depending on the necessary actions, and the flexibility of other operating generation, this could require at least 30 minutes; or longer if it was necessary to start less flexible generation to secure the system.

Action to secure the power system when such shutdown events have been determined as credible could include:

- Establishing region-specific FCAS requirements to ensure that at least part of the FCAS required to manage the shutdown were provided from within the event region, to limit the change in interconnector flows.
- Constraining interconnectors flow into regions below maximum levels, to provide headroom for FCAS from adjacent regions following rapid changes in generation output.
- Limiting the output or maximum operating point of generation that may potentially be subject to a shutdown or increase event, before the event actually occurs, to ensure that any subsequent event could be managed within network limits.
- Implementing additional network constraint equations to manage other network limits due to possible large changes in interconnection flow resulting from rapid changes in generation output.

AEMO has previously undertaken work to incorporate the prediction of large rapid changes in aggregated wind farm output in the NEM into the existing AWEFS system. However, to date these systems have not proven to be sufficiently accurate and reliable when forecasting rapid change in wind generation output, and further work will be required here.

3.6.5 Transmission-connected PV systems

Rapid power output fluctuations from utility-scale PV systems connected to the transmission system due to fast-moving cloud shadows is a phenomenon that may also possibly impact NEM frequency control. This phenomenon would appear to also lie somewhere between the existing regulation and contingency FCAS arrangements.

There are currently no utility-scale PV systems in the NEM of sufficient size for this phenomenon to be material for power system frequency control, though the rapidly decreasing cost of PV technology suggests such projects may appear in future. AEMO is not aware of this cloud shadowing issue having yet been observed to produce system levels impacts with the existing levels of rooftop PV.

AEMO expects that system-level frequency control issues would only be experienced if PV systems of several hundred MW in size were installed within a very small geographic area subject to rapid cloud shadowing. It would also take sustained changes in output to impact power system frequency control, rather than rapid decreases and increases around a relatively constant operating point, although other more local network effects such as voltage control or flicker may arise as a result of rapid changes in output. The potential effect of utility-scale PV systems on frequency control is an issue that requires further investigation and more operational data and experience to more fully understand.

3.6.6 Distribution-connected renewable generation

These studies have focussed on transmission-connected renewable generation, principally wind, and its potential impacts on power system operation. The generation scenario considered for 2020 includes 1,000 MW of new transmission-connected PV generation, though no substantial generation of this type is currently connected in the NEM.

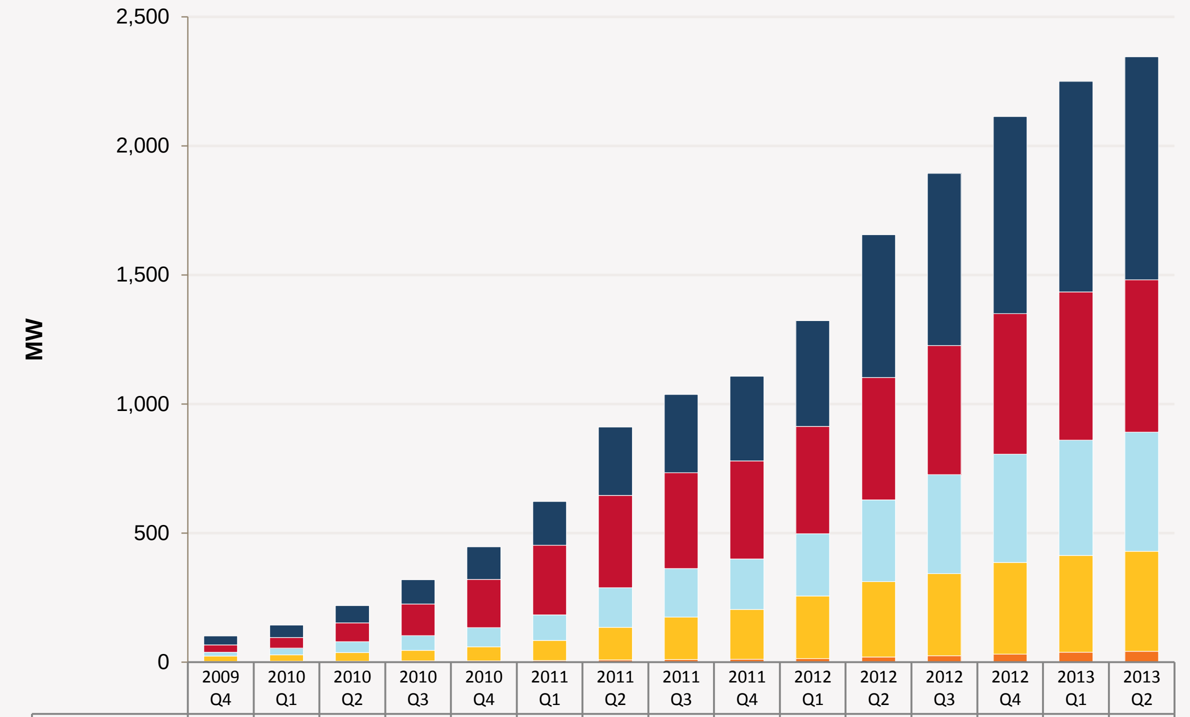
Distribution-connected renewable generation has mainly been considered in these studies as a load reduction when determining the net load on the transmission system.

However, in the course of these studies AEMO identified that distribution-connected renewable generation, principally rooftop PV installations, may also impact on power system operations, particularly AEMO's ability to control power system frequency within the requirements of the Frequency Operating Standards.

The installed capacity of distribution-connected PV generation in the NEM has increased from around 150 MW at the start of 2010, to around 2,350 MW as at June 2013, with further growth in installations ongoing. The installed capacity of this distribution-connected generation is now comparable to the capacity of transmission-connected wind generation in the NEM.

Figure 3-14 below shows cumulative installation of distribution-connected PV systems in the NEM. This data was obtained in June 2013, and is derived from data on the surrender of the Renewable Energy Certificates (REC) associated with the generation, which provides a lagging indicator of actual installations.

Figure 3-14 — NEM distribution-connected PV generation (MW)



	2009 Q4	2010 Q1	2010 Q2	2010 Q3	2010 Q4	2011 Q1	2011 Q2	2011 Q3	2011 Q4	2012 Q1	2012 Q2	2012 Q3	2012 Q4	2013 Q1	2013 Q2
QLD Cumulative	35	47	67	94	127	169	265	303	327	410	553	666	764	816	864
NSW Cumulative	28	41	72	123	186	270	358	372	381	416	473	500	544	574	590
VIC Cumulative	15	26	43	56	74	100	154	188	195	242	318	384	420	446	462
SA Cumulative	21	26	33	41	54	77	126	165	194	242	292	318	355	376	388
TAS Cumulative	2	3	4	4	5	6	9	10	10	13	19	24	31	38	41

The inverters used in these PV systems include protection features to prevent islanding with local load, which presents safety hazards in distribution networks.

Due to the frequency trip settings currently used in some of these inverters, there appears to be the potential for disconnection of significant amounts of this distribution-connected generation following credible contingency events causing changes in power system frequency. This resulting sudden loss of generation could potentially cause power system frequency outside the Frequency Operating Standards for single credible events.

AEMO is aware that many of the inverters used in these systems will disconnect from the power system for power system frequency within the range 49.5 Hz – 50.5 Hz. A frequency change of this size can occur for a single credible contingency event such as disconnection of a large generator or load from the power system, resulting in subsequent disconnection of this distribution-connected PV generation.

Settings for disconnection of this generation for under-frequency conditions appear to vary over a wide range, and AEMO is aware of settings between 47.5 Hz and 49.81 Hz. Frequency disturbances at the higher end of this range can occur for single credible contingency events, particularly in Tasmania, and in South Australia under conditions of separation from the NEM, potentially resulting in disconnection of some of this distribution-connected generation.

The current Australian Standard AS 4777.3, which describes the protection features required for these grid-connected inverters, allows for a wide range of possible frequency trip settings; however, it does not specify the actual settings required. Settings are sometimes specified by the local distribution network operator, particularly for larger installations; however, for many small installations, such as rooftop PV systems, it appears that the inverter settings are typically set at the factory, and left unchanged during the installation process.

In addition to disconnection for sustained changes in absolute frequency, some larger distribution-connected systems may also use rate of change of frequency (RoCoF) as a method of detecting islanded operation. AEMO understands that the RoCoF trip settings used in these systems can be well below the capability required of transmission-connected generation.

A new Australian Standard for grid-connected inverters is currently being drafted, and AEMO is engaging in this process to ensure that its concerns regarding the potential impacts of these inverters on AEMO's control of power system frequency in particular are considered.

The current draft of the new standard appears to require improved capability from these inverters with respect to frequency disturbances, potentially reducing the impact of future inverter-connected generation systems on AEMO's control of power system frequency. AEMO is actively working to better understand the performance of the large existing distribution-connected rooftop PV installation base, and its potential implications for power system operation.

3.6.7 Effect of wind generation on contingency FCAS requirements

Contingency FCAS requirement calculations consider contingency size, system load, and in Tasmania, system inertia levels. Both contingency size and inertia may be affected by increased levels of wind generation, with increased wind generation expected to lead to increased requirements for contingency FCAS.

The levels of wind generation projected for the NEM by 2020 in Victoria, South Australia and Tasmania are high enough to potentially meet the entire minimum load in these regions, assuming no interconnection flows between these regions.

At the extreme, this has the potential to result in zero inertia conditions in all three regions, a condition which would not be operationally viable with respect to frequency control in Tasmania and South Australia due to the potential for extremely high rates of change of frequency following contingency events, unfeasibly high requirements for contingency FCAS, and ultimately no ability to control frequency within the requirements of the Frequency Operating Standards.

These effects of increasing wind generation on contingency FCAS requirements are expected to be most material in Tasmania and South Australia for conditions where they may become separated from the NEM; under these conditions these regions must manage their own frequency only using local generation.

3.6.8 Wind generation and contingency size

Increased wind generation can increase effective contingency size, due to the fault ride through behaviour of modern wind generation and other similar power electronic devices. During fault ride through, wind generation can rapidly reduce real power production for a period of time, in order to prioritise the injection of reactive power into the grid during and immediately after a fault.

Depending on the design of the fault ride through controls, it can take over a second before full real power output is re-established. This loss of active power following a disturbance can be material in low-inertia power systems such as Tasmania, or potentially in South Australia when islanded from the NEM.

The risk is that a fault resulting in a large conventional generator disconnection also results in a temporary loss of real power injection from electrically close wind farms, depending on the location and severity of the fault. This temporarily increases the "effective" size of the generation contingency. The Basslink HVDC Interconnector also exhibits a similar temporary reduction in megawatt flows immediately following a fault near its connection point in Tasmania, potentially further increasing the effective contingency size, depending on flow conditions prior to the fault. Properly identifying and modelling the impact of these fault ride through behaviours requires high quality models of the relevant wind generation, which have been difficult to obtain for some wind generation connections.

Given the potential for low inertia levels and high levels of non-synchronous supply from wind generation and Basslink in the Tasmanian power system, the contingency FCAS requirement calculation is currently under review in Tasmania. This work has identified changes required to incorporate the fault ride through behaviour of wind generation and Basslink, as well as the action of the Basslink Frequency Controller in calculating Tasmanian contingency FCAS requirements. AEMO expects to complete this work by the end of 2013.

3.6.9 South Australian separation from the NEM

South Australia has a synchronous connection the NEM via the Heywood Interconnector, which consists of two transformers, and two AC transmission lines of single-tower, double-circuit design for a distance of approximately 640 km. South Australia is also connected via the HVDC Murraylink Interconnector, but this asynchronous interconnector does not currently have any ability to control frequency.

Under normal operating conditions, separation of South Australia from the NEM is not considered a credible event, as it would require the simultaneous failure of two transmission elements. However, under conditions of planned outage of either of the transmission circuits or transformers forming the AC interconnection, the next credible transmission contingency will result South Australia's separation from NEM.

During calendar years 2010, 2011 and 2012, AEMO's operational records indicate that South Australia was considered at risk of separation for a single credible transmission contingency in this way for between 8% and 18% of the year, due to a range of different planned outages.

During periods where South Australia may potentially become separated due to a single credible contingency event, sufficient FCAS must be available locally to ensure control of South Australian frequency within the Frequency Operating Standard requirements.

Current standards for managing these credible separation events do allow for the potential action of UFLS for such events, when South Australia is importing power from Victoria immediately prior to the separation event. This is based on a specific decision made by the South Australian jurisdiction. Under conditions of potential separation of the South Australian power system, power transfer across potential separation points is limited to +/- 250 MW, to limit the effective contingency size experienced by the South Australian power system if a separation event does occur.

As shown in Table 3-3, the quantities of contingency FCAS registered in South Australia are relatively small, and with high output from wind generation some or all of the generating units providing these services could be economically displaced.

During conditions of potential or actual separation from the rest of the NEM it may be necessary for AEMO to take action to ensure that sufficient local FCAS is available in South Australia. In the absence of other options this could ultimately require AEMO to issue power system directions[33] to generators to operate in such a way as to ensure adequate control of power system frequency in South Australia.

3.7 Mitigation options – frequency control and inertia

AEMO has identified a number of potential impacts on power system performance relating to frequency control and inertia arising from increased installation of wind generation. These include:

- High RoCoF levels following contingency events.

[33] AEMO may direct a registered participant to undertake an action AEMO believes is necessary to maintain or re-establish the power system to a relevant operating state, under clause 4.8.9 of the NER.

- Increased requirement for, and reduced supply of, contingency FCAS.

AEMO has identified a range of possible mitigation options to potentially address these issues. These are not necessarily exhaustive. This report does not seek to identify any preferred option, and AEMO has not yet assessed the costs and benefits of the operational, market and regulatory changes that may be required to implement each option.

3.7.1 Accurately determine contingency FCAS requirements

It is important to accurately determine contingency FCAS requirements, to ensure that the correct amounts of contingency FCAS are obtained to maintain power system frequency remains within the Frequency Operating Standards requirements.

AEMO does not currently consider inertia when determining local South Australian contingency FCAS requirements for conditions where South Australia may become, or is actually separated from the rest of the NEM. A review of South Australian inertia levels has identified that inertia should be considered when determining contingency FCAS requirements in South Australia under such conditions.

AEMO has identified that the calculation used to determine contingency FCAS requirements in Tasmania and South Australia should be updated to more accurately consider the fault ride through behaviour of wind generation within these regions.

AEMO plans to complete this work to update the calculation of contingency FCAS requirements in Tasmania and South Australia by the end of 2013.

AEMO has not identified a need for changes to contingency FCAS requirement calculations in other NEM regions at this time.

3.7.2 Specify power system RoCoF limits

The minimum and automatic access standards for generation to maintain continuous, uninterrupted operation while subject to high levels of RoCoF is described in clause S5.2.5.3 of the NER[34], and the agreed standard is documented in the generator performance standards for new generation connections.

However, the required performance of the power system itself to maintain RoCoF within certain levels is not currently specified. Effectively, the required performance of the power system in terms of RoCoF is currently determined only indirectly, as set by the requirements of connected generation, or any other protection or control systems that may have historically been installed.

For example, correct operation of under-frequency load shedding schemes (UFLS) to stabilise power system frequency following multiple contingency events depend on a RoCoF that is slow enough to ensure sufficient time to detect low frequency conditions, and then taking action to trip load to arrest the declining frequency.

If power system RoCoF levels were to exceed the specified levels for existing generation to withstand under their performance standards, there is also the potential for wide-scale generation tripping and associated supply disruption following contingency events.

It is also not known at this time what, if any, limits may be required on power system RoCoF limits to ensure the continuous operation of small, distribution-connected generation systems, such as rooftop PV. AEMO understands there is the potential for disconnection of some distribution-connected generation systems during conditions of high power system RoCoF levels, potentially increasing the difficulty of maintaining power system frequency within required limits.

System standards could be determined (within the Frequency Operating Standards) to set a maximum RoCoF that the power system must be limited to, for both single credible contingency events and multiple, non-credible events; and the time for which the RoCoF can be present on the power system.

[34] AEMC. Available: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html.

These limits would be generally based on the performance of existing generation, and protection and control systems already connected to the NEM. It may also be necessary in some cases to change the performance or settings of existing control systems, protection systems or other existing generation, to ensure that it can continue uninterrupted operation with a higher RoCoF. For example, there may be some scope to modify existing UFLS to provide the required performance with higher levels of RoCoF. Further investigation is required to fully understand this issue.

Creating a mandated limit on the RoCoF of the power system would provide a clearer target to the TNSPs, DNSPs and AEMO for planning and operation of the NEM in terms of inertia and frequency control, and what levels of RoCoF should be considered when connecting new generation in the NEM, or designing and implementing key emergency control schemes.

AEMO notes that it may be difficult to maintain power system RoCoF levels within specified limits for non-credible events with current NEM systems and processes. In theory the central dispatch process could be used to ensure either minimum levels of power system inertia are maintained, or to limit potential contingency sizes. However, this would represent an important departure from normal current practice for managing power system security through the central dispatch process. At present, AEMO only uses intervention in the central dispatch process to maintain power system security for credible events, or normally non-credible events that have been temporarily declared credible.

Further, due to the response speed required to manage RoCoF within required levels, the central dispatch process would be unable to provide the necessary response after an event actually occurred. Pre-contingent adjustment of generation dispatch would therefore be required in order to use the central dispatch process to manage RoCoF levels for non-credible events.

Due to the potential implications of intervening in the central dispatch process to manage non-credible events, other options capable of providing high response speeds following non-credible contingency events, such as new emergency control schemes or very fast acting generation controls, may ultimately be required to assist in managing power system frequency with high levels of RoCoF.

3.7.3 Management of power system inertia

Low power system inertia due to displacement of other generation by wind can result in both increased requirements for contingency FCAS, and increased levels of RoCoF. Active management of power system inertia is one option that could be used to contain both RoCoF levels and contingency FCAS requirements within manageable limits. AEMO has identified the following options to achieve this, noting that other options may also exist.

- Constraint equations in the central dispatch process can be used to limit the megawatt output of “inertia-less” generation during periods of low power system inertia. This would then require the dispatch of conventional synchronous generation with inertia to meet the supply–demand balance. Transend has already provided AEMO with advice describing limits on the output of Musselroe Wind Farm and Basslink import into Tasmania during periods of low Tasmanian system inertia, to ensure that RoCoF remains within limits required for correct operation of UFLS schemes in Tasmania following credible contingency events during these periods.

  This limit has been implemented in the central dispatch process using constraint equations. Similar arrangements could be established in other regions to curtail wind generation or other forms of inertia-less generation, to ensure the operation of conventional thermal or hydro generation when required to provide the power system with required levels of inertia.
- The possibility of obtaining a “synthetic” inertial response from wind turbines or other forms of asynchronous generation. This capability has not been installed on any generation in the NEM, and there is currently no obligation or incentive for generators to provide this feature. Synthetic inertia can also potentially be obtained during periods of falling power system frequency from power electronic devices that include some form of energy storage, such as high energy flywheel or battery storage systems, installed specifically for this purpose. New technical standards could potentially be used to establish a requirement to provide a minimum level of effective synthetic inertia from newly connected generation, or other arrangements could be established to incentivise the provision of such responses from other devices.

- Arrangements or incentives could be developed to ensure that generation capable of operating in synchronous condenser mode is online when required during periods of low system inertia. Possible arrangements could include establishing new ancillary services requirements to identify the value of “inertia services”, or other incentive mechanisms, such as network support contracts with owners of generation that can operate as synchronous condensers.
- It may be possible to establish incentives for re-engineering existing or retired generating units to operate as synchronous condensers. In addition to providing inertia, these generating units could provide other services, such as a fault level contribution and fast control of reactive output. AEMO is not aware of this retro-fitting of synchronous condenser capability having ever been undertaken in Australia, and its technical and economic feasibility is currently unknown.
- Dedicated synchronous condensers could be installed to raise system inertia levels. Like the previous option, in addition to inertia, installing dedicated synchronous condensers would also allow for provision of other services such as a fault level contribution and fast control of reactive output, which may increase the potential benefit of synchronous condensers over other options. The design and location of dedicated synchronous condensers could be optimised considering the system requirements for these various services.

AEMO notes that there are many outstanding questions around potential market impacts, technical specifications, costs and funding arrangements, and regulatory arrangements for some of these options.

Further work is required to identify which, if any, of these options may be preferred over a business-as-usual approach of using constraint equations in the central dispatch process.

3.7.4 Limit effective contingency size with control schemes

Load or generation contingency size is a key factor when determining both contingency FCAS requirements and power system RoCoF levels. The “effective” contingency size can be limited either through the central dispatch process, or through use of control schemes, to ensure that power system RoCoF levels and contingency FCAS requirements remain within manageable limits.

Generation contingency size can be limited through use of constraint equations in the central dispatch process when required, as a possible method of limiting contingency FCAS requirements and limiting RoCoF to acceptable levels. This arrangement is already used on a limited basis in Tasmania, where single credible generation contingency size is limited to 250 MW under certain outage or other abnormal operating conditions, to minimise the resulting Tasmanian contingency FCAS requirements.

Control schemes offer another option to reduce effective contingency size, by rapidly tripping either load or generation to offset the disconnection of generation or load respectively. Such control schemes require contracts with suitable loads or generators for rapid disconnection, and establishing suitable high-speed, high-reliability controls to both determine tripping requirements, and implement tripping when required. The triggering conditions for such control schemes need to be carefully considered, and may be based on the detection of either certain contingency events ,or certain levels of power system frequency or RoCoF.

Such control schemes are already used in Tasmania to reduce the contingency size from loss of the Basslink HVDC Interconnector to a lower effective value. While large load contingency events can result in high RoCoF or contingency FCAS requirements, AEMO is unable to directly limit load contingency size through the central dispatch process, unless they were offered as scheduled loads. Large load contingency events may in future require other arrangements, such as rapid generator tripping, to at least partially manage frequency outside of the use of contingency FCAS.

Using sophisticated control schemes to manage power system frequency following both credible and non-credible contingency events may offer important benefits, as it can avoid any need to intervene in the central dispatch process prior to a contingency event occurring.

However, at present there are a range of unknown factors around the technical and commercial viability of such arrangements, in particular the availability and willingness of major loads and generators to participate in such arrangements.

3.7.5 Review Frequency Operating Standards

Both regulation and contingency FCAS requirements are ultimately determined by the Frequency Operating Standards requirements, and modifying the existing standards may be a one way to manage future FCAS requirements. A review of the Frequency Operating Standards could be considered, to confirm that they remain appropriate on an ongoing basis.

3.7.6 Participation of renewable generation in frequency control arrangements

Currently, no wind generation in the NEM participates in the markets for the providing FCAS. There is currently no obligation or obvious incentive for them to do so, given the historically low value of FCAS markets compared to energy markets, and the fact that FCAS market registration and participation is voluntary.

At present, providing raise FCAS in particular would typically require wind generators to “spill” wind in order to provide the necessary headroom to raise output. Under current NEM market arrangements this would only be economic if the value of this lost energy production was below the value of the FCAS that it allowed the wind generator to provide.

While other more technically complex methods for the providing increased output from wind generation in response to falling frequency have been proposed by wind turbine manufacturers and in academic literature, these features have not been installed in Australia, and there is currently no apparent economic incentive to do so.

New arrangements could be considered to provide new incentives for, or mandate, the participation of generation in the control of power system frequency under certain specified conditions. This could be through modifying existing technical standards for generation connections to mandate the provision of specified active power responses to frequency disturbances.

Providing such responses to rising power system frequency is likely to be relatively uncontroversial, as this would allow normally unconstrained operation of renewable generation, except under rare conditions when power system frequency rose following a contingency event.

However, mandating the provision of a frequency control response to falling power system frequency may be more controversial; in the absence of energy storage, this may require spilling generation at all times to allow for an increase in output following a fall in power system frequency after a loss of generation.

Technologies including energy storage and very fast control of active power output would increase the range of technical options for rapid control of power system frequency, but such technologies are not yet installed on any material scale in the NEM.

3.7.7 Determine actual frequency control capability

Although new generating units generally choose not participate in FCAS markets, the control systems on modern generation often provide a material “potential” frequency control capability through the ability to rapidly change their active power output in response to changing system frequency.

Rather than recording a nominal or very low effective frequency control capability as the recorded performance standard, it may be prudent when connecting new generation to determine its maximum “actual” or “potential” technical frequency control during the connection process, and record this “actual” capability in the generator performance standards.

While participation in FCAS arrangements would continue to remain voluntary, AEMO expects that registering actual frequency control capability would greatly simplify this generation’s future participation in frequency control arrangements should circumstances change, without imposing substantial additional costs on generators at the time of connection.

3.7.8 Frequency control and Murraylink

As described in Section 3.4.1, the Basslink Interconnector is fitted with a frequency controller, which adjusts the active power transfer on Basslink in response to differences in frequency between Tasmania and Victoria. This allows for the transfer of FCAS between Victoria and Tasmania via Basslink.

The Murraylink Interconnector does not currently provide any frequency control capability, and under normal operating conditions, frequency in South Australia and the rest of the NEM is identical, due to the AC connection via Heywood.

However, under conditions where South Australia has lost its AC interconnection with the rest of the NEM, a frequency controller capability installed on the controls of the Murraylink Interconnector could provide an additional source of FCAS capability to South Australia. This would be particularly useful if separation occurred during conditions where high wind generation had economically displaced other South Australian generation that might otherwise provide local FCAS capability.

The technical or economic issues with this option are currently unclear; however, AEMO believes this option may be worth exploring further, given that it would likely only require control changes to the existing HVDC interconnection.

3.7.9 Additional AC interconnection with South Australia

While there are currently no plans to do so, AEMO notes that establishing an additional, geographically diverse AC interconnection between South Australia and the rest of the NEM would assist in mitigating or even removing the identified impacts of high levels of wind generation on frequency control in South Australia.

An additional AC interconnection would ensure that the frequency and inertia of the mainland power system were both “seen” by South Australia, even after complete loss of the existing high-capacity interconnection at Heywood. This would avoid the existing impacts that can occur when this interconnector is lost.

3.7.10 System load levels

While AEMO cannot directly control power system load levels (other than scheduled loads), it notes that increasing system load (particularly minimum load levels) reduces contingency FCAS requirements by increasing the frequency-dependent load relief effect experienced on the power system for a given change in frequency.

Conversely, major industrial load shutdown or other factors reducing minimum system load levels can lead to systematic increases in contingency FCAS requirements. Better forecast information on likely minimum power system load levels would assist in understanding and managing potential future contingency FCAS requirements.

3.7.11 Frequency control special protection scheme and wind generation

The current design of the Tasmanian frequency control special protection scheme (FCSPS) trips hydro generation only, and if insufficient hydro generation were available in Tasmania, Basslink transfer from Tasmania to Victoria would be constrained. Up to 600 MW of Tasmanian hydro generation is required to be available for tripping to support maximum transfers on Basslink from Tasmania to Victoria, based on the current FCSPS design.

High levels of wind generation in Tasmania could result in constraints on the transfer of power from Tasmania to Victoria on Basslink during periods of low demand and high wind generation, as wind generation may displace some of the hydro generation required for operating the FCSPS. To maintain maximum export capability from Tasmania to Victoria during periods of high wind generation and low synchronous generation, it may be beneficial to include the tripping of Tasmanian wind generation in the FCSPS design.

This would also minimise the removal of inertia from the Tasmanian power system due to the tripping of hydro generation following the loss of Basslink, which occurs precisely at a time when it would be desirable to maintain inertia in Tasmania following electrical separation from the mainland.

CHAPTER 4 - FAULT LEVELS AND MINIMUM SYNCHRONOUS GENERATION

4.1 Introduction

This chapter assesses the potential impact of increased wind generation on power system fault levels, some of the consequences of any resulting changes to power system fault levels, and potential options that may be available to manage power system fault levels if necessary.

This chapter also seeks to explain why minimum quantities of synchronous generation may need to remain online in some National Electricity Market (NEM) regions, and discusses some of the consequences this may cause.

4.2 Fault levels

Fault level, or short-circuit level, is a measure of the current that will flow into a fault, or short circuit, at a given point in the power system. Fault level is measured directly in Amps, or as the product of fault current and the pre-fault voltage, to give a figure in megavolt amperes (MVA).

Fault level can be seen as measure of system "strength", with a high fault level indicating a "strong" power system and a low fault level indicating a "weak" power system.

During a fault, the short-circuit current is supplied by the generators connected to the system at that time, so fault levels increase and decrease as generation patterns change. Fault levels at a point in the power system are most affected by the generators located close to that point. If there are many generators in service close to the fault location, the fault level will be high at that point; if no generators are in service nearby, the fault level will be lower.

Fault levels are generally lowest under minimum load conditions (when few generators are required to be in service), and also in more remote or weakly connected parts of the network (furthest from major generation sources). AEMO uses power system studies to calculate fault levels for various system conditions. This information is used for:

- Selecting circuit breakers, which must be rated to interrupt the maximum possible fault current at that point in the power system.
- Mechanical design, where equipment must withstand the high mechanical forces that occur during a fault.
- Design of earthing and other safety systems.
- Design of power system protection systems, which must consider both maximum and minimum fault level conditions to ensure correct operation.

4.2.1 Wind generation and fault levels

Modern wind turbines typically produce lower levels of fault current than conventional synchronous generators of equal megawatt rating. The difference depends on the technology used in the wind turbines and the location of the fault relative to the wind generation.

Older type 1 and 2 wind turbines are essentially conventional induction generators directly connected to the grid, without any rotor control (type 1), or with variable rotor resistance (type 2). Due to the lack of excitation on the rotor, these machines will demagnetise rapidly following a balanced three-phase fault. They will not produce a sustained contribution to nearby faults after approximately three or four cycles, though they may produce significant fault current immediately after fault occurrence. For asymmetrical faults, the induction generators may not become completely demagnetised due to presence of unbalanced rotor induction, so more substantial and complex fault currents may persist.

Type 3 doubly fed induction generators can exhibit a range of fault current behaviours, depending on the precise design and settings of the rotor power converter and its associated controls, and the location of the fault relative to the turbine.

For less extreme voltage dips caused by distant faults or faults with appreciable impedance, the rotor power converter may remain in control of the machine. From a fault level perspective, these generators can act like a current source with the same rating as the generator. For close-in faults, the rotor-side power electronic converter may be bypassed by a crowbar mechanism in order to prevent damaging transient conditions. In this mode, the rotor-side converter loses control and the type 3 machine is more akin to a conventional induction generator with fixed external rotor resistance. The situation is further complicated when considering the behaviour of type 3 machines in response to asymmetrical faults.

Type 4 full converter wind turbine fault response is fully determined by the design and settings of the grid inverter, as the generator itself is fully de-coupled from the power system. The inverters are typically rated at or slightly above the machine rating, so they can only produce sustained fault current similar to the machine rating; this avoids damage to the grid-inverter electronics. For a fault close to the turbine resulting in significant voltage depression, these inverters may inject full-rated current into the fault. For more remote faults, they may not reach their current limits, depending on the voltage and reactive power control settings of the inverter.

Due to the complex power electronics used in modern wind turbines, accurate calculation of short-circuit currents and fault levels for a given power system condition with increasing levels of wind generation will become more complex, and will require different modelling techniques to those used previously.

Developing standard approaches for determining the fault current contribution of wind generation for both close-in and more remote faults is currently an active area of industry research. AEMO will need to work with transmission network service providers (TNSPs) to determine standard techniques for assessing the fault contribution of wind generation more accurately as wind generation capacity increases.

4.2.2 Power system fault level variation

Power system fault levels are normally highest during periods of maximum demand, when more synchronous generation can be online to meet demand. Increased wind generation can increase system fault levels during these periods, as all wind turbines may be in service, but with low levels of output. This adds to the existing fault level contribution from synchronous generation required to meet demand.

However, during periods of low system demand and high wind, where wind generation may economically displace conventional synchronous generation output and ultimately result in fewer synchronous generating units online, power system fault levels may be reduced. This is due to the typically lower fault-current output of wind generators compared to synchronous generators of equal megawatt rating.

This suggests that installing large amounts of wind generation in the NEM may result in normal power system fault levels varying widely, with some points in the system systematically experiencing higher fault levels—depending on where the wind generation connects to the network—and some points usually operating below existing fault levels.

4.2.3 Short-circuit ratio

A common measure when connecting generation to a power system is the short-circuit ratio (SCR) at the connection point of the generation facility to the grid, or the point of common coupling (PCC). The SCR is the ratio of the power system fault level at the generation connection point (measured in MVA) to the rated generation megawatt. An important value is the minimum SCR, which occurs under conditions of minimum system fault levels.

To ensure stable operation of modern power electronic devices (such as wind generators), some minimum value of SCR is required at the PCC. In particular, a minimum level of SCR is required to ensure the wind generator can successfully ride through nearby faults and re-establish stable operation after the fault is cleared. This is required in the performance standards determined for all new generation connections.

AEMO understands that the actual minimum level of SCR required at the PCC for stable operation of wind generation is typically in the range of three to five; however, this value can be difficult to identify precisely, and varies with the specific turbine technology and wind farm design. Exact minimum SCR requirements for the majority of wind farms currently connected to the NEM are not currently known, as this information is not normally identified during the connection process.

Table 4-1 below shows minimum fault currents (in kA) required at the PCC for a 100 MW generation connection to produce the given SCRs. These minimum fault current requirements scale linearly with the generation size.

Table 4-1 — Minimum fault level required for a 100 MW generator

Voltage	66 kV	110 kV	132 kV	220 kV	275 kV	330 kV	500 kV
PCC short-circuit ratio = 5	4.4 kA	2.6 kA	2.2 kA	1.3 kA	1.1 kA	0.9 kA	0.6 kA
PCC short-circuit ratio = 3	2.6 kA	1.6 kA	1.3 kA	0.8 kA	0.6 kA	0.5 kA	0.4 kA

Detailed studies using very accurate modelling of wind turbines are necessary to confirm the correct operation of wind generation under low fault level conditions. These studies are likely to require input from wind turbine manufacturers in order to fully identify all internal plant limits related to operation in weak power systems.

SCRs are also important for the operation of HVDC links, where a minimum value of 2 to 3 at the grid connection point is generally required for stable operation. This is currently relevant for operating the Basslink Interconnector. Under low fault level conditions at the Tasmanian end of Basslink, constraint equations are currently used in the central dispatch process to limit power transfer on Basslink from the mainland into Tasmania, ensuring stable operation.

4.2.4 Fault levels and protection

Knowledge of power system fault levels is important for the design of protection systems, which must consider both maximum and minimum fault level conditions. Minimum fault level conditions can be determined using minimum generation scenarios, or more extreme scenarios of system restoration following a complete power system collapse.

As a national power system operator, AEMO does not own or manage protection systems across the NEM. Network planners and operators will need to consider the effects of system fault level changes due to increased wind generation, to ensure ongoing correct operation of protection systems.

One issue recently identified by AEMO is the different response of full power converter (type 4) wind generation to unbalanced faults, compared to conventional synchronous generation. This can affect the apparent impedance determined by distance protection relays, which can in turn affect the performance of those relays. Addressing this issue to ensure ongoing correct operation with increasing levels of wind generation may require changes to existing protection systems, or in some cases, re-designing or replacing existing protection systems.

4.2.5 Voltage control

Fault levels affect the power system voltages that occur during system disturbances such as faults. Low fault levels can result in larger voltage drops during a fault, difficulty in maintaining voltages below maximum operating voltage limits after disturbances, and slower recovery of normal system voltages after faults are cleared.

The speed of power system voltage recovery after disturbances must be considered when designing controls on wind generation affecting fault ride through behaviour. Under low fault level conditions it may be necessary to deliberately slow down the recovery of real and reactive power from a wind generator after a fault. Due to the slow voltage recovery characteristics of the system under low fault level conditions, it may be necessary to limit the rate of recovery to below a plant’s technically possible maximum rate.

Low power system fault levels can also result in increased levels of voltage flicker, which is particularly an issue with older wind turbine designs based on direct-connected induction generators.

4.2.6 Managing system fault levels

At present, fault levels are only managed when they are likely to become too high. This is typically achieved by reconfiguring or rearranging the transmission system. Other options for managing high fault levels include installing series reactors to increase system impedance, or increasing the rating of equipment to withstand higher fault levels. Increased levels of wind generation may increase fault levels at some points in the transmission system; however, options to manage these higher fault levels are generally already well understood.

Increased levels of wind generation could potentially require new arrangements to manage low fault levels, particularly to maintain minimum SCRs at wind farm connection points, or minimum fault levels at other selected points in the power system.

4.2.7 Identifying minimum required fault levels

As wind generation increases, it will become increasingly important to understand exactly what SCRs or fault levels must be maintained to ensure ongoing stable operation of wind generation and HVDC links, while meeting other system performance requirements. This is particularly the case in South Australia, Tasmania and Victoria.

The scenarios this report investigates would potentially allow wind generation to meet the entire load in these regions during periods of high wind and low demand; however, this may not be feasible due to inadequate SCRs at the wind farm or HVDC connection points, among other reasons. Very low SCRs may also create difficulties in managing system voltages within required limits before, during and after power system disturbances.

The minimum required SCR or fault level limits will then determine whether intervention may be required to manage fault levels, and set the network limits or requirements for network and system operators to target.

4.2.8 Maintaining minimum fault levels

Relatively few options are available to directly manage low power system fault levels. AEMO does not expect that the fault current contribution of wind generation itself can be significantly increased in the future. This is because the fault current contributions of new wind turbines are limited by the ratings of power electronics, and no significant technology changes are expected in the short term.

The only available method at present to maintain minimum fault levels is to ensure a minimum quantity of synchronous machines are online, to obtain the fault level contribution or “fault level services” they provide.

4.2.9 Synchronous generation

AEMO could use the central dispatch process to maintain adequate short-circuit levels at some locations.

Constraint equations in the central dispatch process to limit the total amount of generation from non-synchronous sources (such as wind) could be applied under appropriate system conditions; typically low system demand. By subtraction, these constraint equations would then ensure that sufficient synchronous generation providing higher levels of fault current must be dispatched online to meet the demand.

During such periods, low energy prices may not provide sufficient incentive for existing generation to remain online. Network support agreements, some form of new ancillary services requirement, or other arrangements outside of the central dispatch process, could be used to provide the necessary incentives to ensure operation of sufficient conventional synchronous generation when required to ensure adequate short-circuit levels.

4.2.10 Synchronous condensers

Synchronous condensers provide similar levels of fault current to similarly sized synchronous generating units when they are connected, and they could potentially be used to manage network fault levels. Installation of dedicated synchronous condensers has been used overseas when connecting HVDC links to weak power systems. This raises the local short-circuit level at the grid connection point, and could also be of use for wind generation connections in weak areas of the power system.

In some NEM regions, hydro generators have contracts with AEMO and are paid to run in synchronous condenser mode when required to provide voltage control services. It is also noted that some hydro generators are observed to run in synchronous condenser mode at times without contracts requiring them to do so.

The central dispatch process cannot be used directly to manage the operation of synchronous condensers. Subject to an evaluation of the relative costs and benefits, it may be possible to establish some form of ancillary service requirement or contract for providing fault level services. These would provide the necessary incentives to ensure that these synchronous condensers were made available when required.

Alternatively or in addition, network operators could install dedicated synchronous condensers at strategic locations on their own networks to maintain minimum fault levels.

4.3 Minimum levels of synchronous generation

Conditions of high wind generation, low demand and low synchronous generation can result in low power system inertia, high RoCoF levels, high contingency FCAS requirements and low fault levels. As wind generation levels increase, it is still unclear which of these issues will ultimately form the most material limit on NEM power system operation.

In the 2020 scenario considered in this report, there is sufficient wind generation capacity installed to fully supply the minimum load in Victoria, South Australia and Tasmania. Under high wind and low demand conditions, there are currently no specific limits in the central dispatch process to prevent 100% of the regional load from being supplied by wind generation under high wind conditions, if this generation was offered sufficiently cheaply, and sufficient network capability existed to allow it to run unconstrained.

At present, AEMO could potentially manage the issues identified in this work by requiring a minimum level of conventional synchronous generation online, or by curtailing the amount of non-synchronous generation online, particularly under conditions of low demand and high wind generation output. There are several other potential reasons why it may be necessary for AEMO to maintain a minimum quantity of synchronous generation online to ensure the power system remains in a secure operating state. These are outlined below.

4.3.1 Potential islanding

Tasmania is always at risk of islanding from the mainland due to a single credible contingency (trip of Basslink).

Over the last three calendar years, AEMO’s operational records indicate that South Australia has been at credible risk of islanding between 8% and 18% of the year due to planned outages. South Australia is connected to Victoria through a single alternating current (AC) tower line carrying two separate transmission circuits over a total distance of approximately 640 km. While simultaneous failures of such double-circuit lines are rare, and are not normally considered to be credible contingency events, such events can and do occur.

Immediately following islanding from the rest of the NEM, these regions must have sufficient online inertia, and sufficient generation with frequency control capability, to be able to regulate their own frequency within the Frequency Operating Standards requirements for an islanded region.

This may require that a minimum quantity of conventional synchronous generation is maintained online at all times in Tasmania and South Australia, to provide both a minimum level of inertia, and to potentially provide frequency control capability. This effectively forms a hard limit on very high levels of instantaneous wind penetration in these regions.

Further studies would be needed to determine the absolute minimum levels of both inertia and frequency control capability required in both Tasmania and South Australia to allow ongoing viable frequency control of these systems under sudden islanding conditions, and any operational limits that may exist due to the ability of generation within these regions to provide frequency control services.

4.3.2 Dynamic reactive capability

Minimum levels of dynamic reactive plant capability near key load centres may be required for adequate control of system voltages. The requirement can be met by: conventional synchronous generation or synchronous condensers; static VAR compensators (SVCs) or similar devices; or potentially by wind generation, if it can provide the necessary mix of static and fast acting dynamic reactive capability. Where this requirement has historically been met by conventional synchronous generation, there is a risk that generation displacement by more remote wind generation may degrade system voltage control capability.

Depending on available sources of dynamic reactive capability, this issue may require a minimum quantity of conventional generation online near large load centres to provide the required dynamic reactive capability to provide fast-acting voltage support following contingencies.

4.3.3 Power system stabilisers

ElectraNet, the South Australian TNSP, has advised AEMO that a minimum number of generators fitted with power system stabilisers (PSS) are required to be online in South Australia to allow maximum transfers between South Australia and Victoria on the Heywood Interconnector. This limit is based on the need to maintain adequate damping of power system oscillations under high power transfer conditions. When insufficient generators fitted with PSS are in service, the transfer capability between Victoria and South Australia is currently automatically limited using constraint equations in the central dispatch process.

At present, this limit based on availability of PSS rarely results in power transfer capability restrictions. It may, however, restrict the export of energy from future wind generation in South Australia as increasing wind generation displaces conventional synchronous generation fitted with PSS.

This issue has not been considered further in these studies, and future study will be required to fully identify ongoing limits to power transfers on the Heywood Interconnector based on damping of power system oscillations with increasing levels of wind generation in South Australia.

4.3.4 Minimum stable operating levels

Many forms of thermal generation are only designed to operate over a limited load range below their maximum output, and have long start-up and shutdown times. To avoid shutting down and restarting within a short period, or operating below minimum stable limits, these less flexible generators may need to adopt operational practices or bidding behaviours that ensure minimum stable output levels are maintained. Some hydro units also have minimum stable operating limits, though they are typically lower as a percentage of rated capacity than for thermal units. Hydro units also tend to have much greater rapid unit shutdown and start-up capability than thermal generating units.

Better understanding of this operational flexibility issue will become important as wind generation increases, as it could effectively result in “competition” for dispatch between inflexible thermal units and low-priced wind generation during some relatively short periods of high wind and low demand. During these periods, inflexible thermal units may strongly wish to remain connected, even if only at minimum stable operating levels, given the costs and time associated with complete unit shutdown and start-up.

While the outcome of this behaviour may be to retain minimum levels of synchronous generation online, it is based on operational decisions that are hard to predict in advance and therefore cannot be relied on.

There are potential risks arising from the lack of flexibility, and long start-up and shutdown times of some existing thermal plant, particularly when combined with the potential inaccuracy of forecasts of demand and wind generation levels over the timeframes involved in the start-up and shutdown (within-day timeframes).

For example, significant over-forecasting of wind generation output several hours in the future introduces the risk that inflexible thermal plant may be de-committed by its operators during periods of high wind generation. It may then not have sufficient incentive or warning to start, or reach the necessary operating levels if required.

The NEM currently has a significant amount of relatively fast start plant, mainly in the form of open cycle gas turbines and hydro generation. This helps to mitigate this risk, as it can replace the output of less operationally flexible plant that may have been de-committed. At lower levels of wind penetration and wind forecasting errors, this issue may result in inefficient use of more expensive fast start plant, to compensate for the inflexibility of cheaper plant in meeting the supply–demand balance.

However, at very high levels of wind penetration, inaccurate wind forecasts and lack of thermal plant flexibility could potentially result in de-commitment of large amounts of inflexible thermal plant. Inaccurate forecasts of future wind generation output may ultimately affect power system reliability and security, due to the possible inability of the remaining generation fleet to meet demand due to plant flexibility limits. These studies suggests that AEMO needs to further assess the ability of its existing systems and processes to identify the possibility of these issues, and then identify what measures might be required to mitigate them.

Modifying AEMO's existing pre-dispatch and short term projected assessment of system adequacy (ST PASA) processes to assess the possible operational consequences of various levels of wind forecast error would be one potential way to do this.

CHAPTER 5 - INTERCONNECTOR LIMITS

5.1 Introduction

This chapter summarises the impacts on key interconnector transfer limits identified in this study arising from increased wind generation. The key interconnector limits identified for the study are outlined in Section 2.5.1. The methodology used to assess the impact of increased wind generation on the interconnector limit is described in Section 8.1.

5.2 Transient stability

The results from assessing the effect of wind generation on interconnector transient stability limits are presented as sensitivity factors. These factors describe the change in the key existing National Electricity Market (NEM) interconnector limits for given wind generation megawatt levels in a given wind bubble. Sensitivity factors determined from these studies are summarised below in Table 5-1.

Table 5-2 shows the maximum change in the relevant limit, which is found by multiplying the new 2020 wind generation capacities listed in Table 2-6 to Table 2-10 in a given wind bubble by the sensitivity factors shown in Table 5-1. Table 5-2 only incudes wind bubbles with a maximum impact of at least 10 MW.

Table 5-1 — Wind bubble sensitivity factors for critical transient stability limits

Wind bubble	VIC to NSW (Fault on Hazelwood – South Morang)	VIC to SA (Loss of largest SA generator)	QLD to NSW (Fault between Bulli Creek and Armidale)	QLD to NSW (Trip of one Boyne Island potline)
CS	-0.72	-0.56	-0.03	-
EPS	-0.19	-1.94	-	-
FLS	-	-	-	-
FWN	-0.19	-	-0.07	-
HUN	-	-	-0.36	-
MNS	-0.57	-0.92	0.11	0.16
MRN	-0.10	-	-	-
MUN	-	-	0.26	-
NEN	-	-	-0.33	-0.46
NWV	0.31	0.27	-0.31	-
SEN	-	-	-	-
SEV	-0.10	-	-	-
SWQ	-	-	0.58	0.51
SWV	0.10	0.24	-0.14	-0.04
WCS	-0.05	-1.40	-	-
WEN	-	-	-	-
YPS	-0.08	-1.40	-	-

Table 5-2 — Maximum change in interconnector limit based on 2020 installed wind generation

Wind bubble	VIC to NSW (Fault on Hazelwood – South Morang)	VIC to SA (Loss of largest SA generator)	QLD to NSW (Fault between Bulli Creek and Armidale)	QLD to NSW (Trip of one Boyne Island potline)
CS	-1,965	-1,528	-82	-
EPS	-	-87	-	-
FLS	-	-	-	-
FWN	-136	-	-50	-
HUN	-	-	-45	-
MNS	-373	-602	72	105
MRN	-84	-	-	-
MUN	-	-	70	-
NEN	-	-	-103	-144
NWV	274	238	-274	-
SEN	-	-	-	-
SEV	-16	-	-	-
SWQ	-	-	154	136
SWV	29	71	-41	-12
WCS	-10	-276	-	-
WEN	-	-	-	-
YPS	-14	-251	-	-

5.2.1 Victoria to New South Wales power transfer on Victoria – New South Wales

The studies undertaken for this report suggest that wind generation levels in wind bubbles CS, MNS and NWV have the largest sensitivities for changes in the Victoria to New South Wales transient stability limit. In these studies there is approximately 2,700 MW of new wind generation modelled in the CS wind bubble, which spans the Victoria to South Australia border area across the Heywood Interconnector and into South Australia.

The critical contingency for Victoria to New South Wales power transfer based on a transient stability limit is a Hazelwood – South Morang 500 kV line fault in Victoria. This fault can result in a large active power reduction from generation in the CS wind bubble, due to the fault ride through behaviour of wind generation, as a result of the relatively strong electrical connection between the 500 kV fault and the electrical connection points of this wind generation. High levels of wind generation in the CS wind bubble can also displace large amounts of conventional generation, substantially reducing power system inertia, particularly in Victoria.

A large amount of in-service wind generation in the CS wind bubble also has the potential to adversely impact stability of the comparatively smaller South Australia region by similar mechanisms.

The study found that generation in the NWV wind bubble has a positive factor. This could be because new wind generation installed at Bendigo, Horsham, and Ballarat is modelled as providing additional fast-acting reactive compensation along the 220 kV network. This improves transfer capability, while the smaller amount of installed wind generation in this bubble results in less displacement of other generation in Victoria.

MNS has a new wind generation capacity of around 650 MW, which is enough to displace key synchronous generators in South Australia. This could reduce system inertia in South Australia, and increase the rate at which South Australia machines accelerate out of synchronism following a fault applied at Hazelwood. More distant wind bubbles such as NEN and SWQ were found to have no material effect on the limit.

5.2.2 Victoria to South Australia power transfer on Heywood

The Victoria to South Australia transient stability limit equation demonstrated high sensitivity factors for wind bubbles EPS, WCS, YPS, MNS and CS. The very high negative sensitivity factors for EPS, WCS for YPS, and MNS wind bubbles also reflect the fact that wind generation located within these bubbles is electrically relatively close to the critical fault considered for this limit (a fault close to Northern Power Station).

When considered with the proposed wind farm capacities in the wind bubbles, these negative sensitivity factors in 2020 are comparable to the factors found for wind generation in the existing Victoria to South Australia transient stability equation derived using the same transient disturbance (trip of the largest generator block in South Australia). This provides increased confidence in the results of these studies.

The positive coefficients in wind bubbles SWV and NWV are also consistent with the sensitivity factors for the Victoria to New South Wales limit equation. The generation in these wind bubbles appears to support interconnector transfers in both Victoria-to-New South Wales and Victoria-to-South Australia directions due to the support they can provide to the power system at their assumed connection points following disturbances.

5.2.3 Queensland to New South Wales power transfer on QNI

The calculated sensitivity factors for the impact of new wind generation on the Queensland to New South Wales limits as shown in Table 5-1 are comparable for the two different faults considered when determining this limit: the fault between Armidale and Bulli Creek, and the Boyne Island smelter potline trip. In particular, the SWQ wind bubble was found to have a large, positive sensitivity factor for both the limits. The SWQ wind bubble is at a strategic location of the Queensland 275 kV network (Greenbank and Blackstone), and new wind generation at this point was found to improve the ability of the Queensland power system to transfer additional power to New South Wales.

Wind bubbles NEN and HUN were both found to have a negative impact on QNI limits for southward flow. This is not unexpected as generation in both wind bubbles can increase power flow on already heavily loaded portions of the New South Wales power system. However, this can depend on which generation is assumed to be displaced by the increased wind generation. For example, if QNI is flowing south into New South Wales (Dumaresq) at around the existing transient stability limit, the additional megawatt capability provided from NEN and HUN on top of existing Liddell and Bayswater units will increase loading on the 330 kV network south of the Hunter Valley, which can in turn lower system stability.

Interestingly, these studies suggested that wind bubble NWV has a negative impact as well. This NWV impact has already been shown to be material with respect to the Victoria to New South Wales transient stability transfer limit.

5.3 Voltage stability

The results from assessing the potential impact of new wind generation on existing interconnector voltage stability limits are expressed as sensitivity factors. Again, these factors describe the change in the key existing NEM interconnector limits for a given wind generation megawatt output in a given wind bubble. The existing voltage stability interconnector limits considered in this work are described in Section 2.5.3, and the methodology used to determine the sensitivity factors reported below is described in Section 8.1.2.

Sensitivity factors determined from these studies are summarised below in Table 5-3 to Table 5-6. They also show the actual megawatt impact of each particular wind bubble. This is calculated from the wind bubble sensitivity factor and the megawatt capacity of new wind generation modelled in that wind bubble.

Only wind bubbles with a maximum impact of at least 10 MW are reported.

5.3.1 New South Wales to Queensland power transfer limit on QNI

Two separate transmission contingencies are considered when determining the existing transfer limit from New South Wales to Queensland on QNI based on voltage stability: the loss of large generation in Queensland (typically Kogan Creek), or a fault on a 330 kV line between Liddell and Muswellbrook.

Only the NEN wind bubble was shown to have a material impact on the New South Wales to Queensland voltage stability transfer limit. Injection of active and reactive support at Armidale 330 kV—the assumed connection point for the NEN wind bubble—was found to improve the voltage stability transfer limit, due to reduced network loading and reactive losses in the area.

Table 5-3 — Impact of wind bubbles on the NSW to QLD transfer limit on QNI

Wind bubble	Loss of Kogan Creek		Loss of Liddell–Muswellbrook 330 kV line	
	Sensitivity factor	Maximum impact (MW)	Sensitivity factor	Maximum impact (MW)
NEN	0.2563	80	0.3887	122

5.3.2 Victoria to South Australia power transfer limit on Heywood

Loss of a large generator in South Australia typically determines the voltage stability limit for transfer from Victoria to South Australia on the Heywood Interconnector. The EPS and MNS wind bubbles were found to have the largest sensitivity factors for new wind generation on the existing Victoria to South Australia voltage stability transfer limit.

As increased generation in the MNS wind bubble displaced generation providing reactive support closer to the major Adelaide load centre, the transfer limit was found to degrade. The CS wind bubble, which includes generation around South East (the voltage collapse area), produced a small increase in the transfer limit.

The EPS and WCS wind bubbles were found to have a marginally positive megawatt impact on the Victoria to South Australia transfer limit. The impact of the remaining wind bubbles was less than 10 MW.

Table 5-4 — Impact of wind bubbles on the VIC to SA transfer limit on Heywood

Wind bubble	Loss of Northern Unit	
	Sensitivity factor	Maximum impact (MW)
CS	0.0094	26
EPS	0.2654	12
MNS	-0.1948	-128
WCS	0.0536	11

5.3.3 New South Wales to Victoria power transfer limit on Victoria – New South Wales

Either loss of a large generating unit in Victoria, or loss of a 330 kV line between Murray and Dederang define the voltage stability limit for transfer from New South Wales to Victoria, with voltage collapse typically occurring in southern New South Wales.

These studies identified that wind generation in a number of wind bubbles in Victoria and southern New South Wales resulted in a material improvement to the New South Wales to Victoria voltage stability transfer limit. Generation in the MUN wind bubble had the largest sensitivity factor for changes in this limit, as it provides active and reactive support close to the voltage collapse area.

Increased wind generation in regional and South West Victoria as well as South West New South Wales (the CS, SWV, NWV and FWN wind bubbles) reduces flows and provides reactive support for the 220 kV network around Red Cliffs, resulting in higher flows through the stronger 330 kV network. Generation in these wind bubbles results in improvements to the voltage stability transfer limit by reducing the loading on lines around Darlington Point, the voltage collapse area.

In contrast, the HUN and NEN wind bubbles provide a marginally negative impact on the New South Wales to Victoria voltage stability transfer limit due to displacement of generation that may otherwise support the network in the area of voltage collapse. The impact of the SEN wind bubble was marginally above the threshold for inclusion for the Loy Yang unit contingency, but was below the threshold for the loss of the Dederang–Murray 330 kV line contingency.

Table 5-5 — Impact of wind bubbles on the NSW to VIC transfer limit on VIC–NSW

Wind bubble	Loss of Loy Yang unit		Loss of Dederang–Murray 330 kV line	
	Sensitivity factor	Maximum impact (MW)	Sensitivity factor	Maximum impact (MW)
CS	0.0998	272	0.1026	280
FWN	0.6276	448	0.6390	457
HUN	-0.0866	-11	-0.0856	-11
MUN	0.9028	242	0.8379	225
NEN	-0.0492	-15	-0.0368	-12
NWV	0.2459	217	0.2718	240
SEN	0.1244	15	-	-
SEV	0.1558	26	0.1247	20
SWV	0.4825	142	0.5117	151

5.3.4 Snowy to central New South Wales power transfer limit

This limit is determined by loss of a 330 kV line in southern New South Wales resulting in voltage collapse in southern New South Wales. At present, this is not a very material limit in the NEM; however, it was considered due to the potential for establishing significant new wind generation in the southern New South Wales area.

Generation in the SEN wind bubble provides local generation to the voltage collapse area, and was found to improve the voltage stability transfer limit. The MRN wind bubble was found to have a negative effect on the voltage stability transfer limit. Increasing MRN generation increases the power flow from Yass to Canberra and decreases the reactive power support from Yass to Canberra.

These studies suggest that wind generation in the WEN, HUN and NEN wind bubbles may improve the Snowy to New South Wales voltage stability transfer limit by supplying nearby load, and reducing New South Wales intra-regional transmission flows.

Table 5-6 — Impact of wind bubbles on the Snowy to central NSW power transfer limit

Wind bubble	Loss of Lower Tumut–Canberra 330 kV line	
	Sensitivity factor	Maximum impact (MW)
MUN	-0.66	-178
FWN	-0.2169	-155
CS	0.0606	165
MRN	-0.19	-159
HUN	0.5108	64
NEN	0.1880	59

SEN	0.3585	43
SWV	0.1764	52
WEN	1.1632	36

5.3.5 Effect of wind generation on interconnector limits

The study results shown above suggest that there is potential for changes in key existing NEM interconnector transfer limits with increased wind generation. They suggest the possibility of both increases and decreases in interconnector limits, which can depend on the location of generation economically displaced by wind.

Changes in interconnector transfer limits based on voltage stability are less likely to be tied to the specific generation technology, as the changes observed in these limits appear to be more determined by both the active and reactive power support modelled at the different connection points assumed for wind generation. If other forms of generation were to be installed at these locations with similar active and reactive power capabilities, it is likely that similar interconnection limit changes would result.

The changes in transient stability limits, however, are more closely linked to the specific characteristics of wind generation. Reduced power system inertia resulting from a higher proportion of wind generation can both increase and decrease transient stability limits, depending on the nature of the limit, and where the reduction in inertia is located.

Wind generation also responds quite differently to system disturbances, such as the voltage dips that can occur following a nearby fault. As part of their fault ride through strategies, modern wind turbines can rapidly reduce active power output for a period of time and, depending on control and setting design, can take longer than one second to stably re-establish full active power production.

When there are large amounts of wind generation connected at a single point in the transmission network, these fault ride through behaviours may be important in determining transient stability limits. It is also possible that new, unforeseen transient stability limitations may appear with large-scale installation of wind generation. AEMO's current studies only considered known, existing transient stability limits in the NEM.

5.4 Oscillatory stability

There are two key existing oscillatory stability limits in the NEM. These limit South Australia to Victoria combined power transfer on the Heywood and Murraylink interconnectors, and Queensland to New South Wales power transfers on QNI.

Previous indicative studies by AEMO and the respective jurisdictional planning bodies suggest that the existing oscillatory stability limits can be raised above their current values at relatively low cost or with minor control adjustments or installations. The studies suggest that under favourable operating conditions, the oscillatory stability limits will be higher than the underlying thermal capability of these interconnectors, and will no longer need to be considered when determining interconnector limits.

The studies undertaken for this report test the above assumption using power system scenarios with high interconnector power transfer levels and high levels of wind generation. The results were examined to ensure that power system damping remains adequate under these conditions, as required by clause S5.1.8 of the NER.

AEMO notes that the studies undertaken for this report were not comprehensive, and further investigation will ultimately be required to accurately determine the effect of increased wind generation on power system damping under a range of power system operating conditions. Further information on the methodology used to determine oscillatory stability is provided in Section 8.1.3.

5.4.1 Queensland to New South Wales oscillatory stability limit on QNI

An oscillatory stability limit of 1,400 MW for flow from Queensland to New South Wales on the QNI was assumed for the purposes of the studies undertaken for this report. Studies were performed for scenarios with South

Australian total export of 870 MW, and QNI southwards flow of 1,400 MW, as previous studies show that some interactions between the two (such as a high South Australia to Victoria transfer) may deteriorate the QNI mode damping.

AEMO used time domain analysis to assess power system damping after a severe disturbance. The simulated disturbance was a line-to-line-to-ground (LLG) fault and the trip of the Greenbank static VAR compensator (SVC) in Queensland.

Key findings of this investigation are summarised as follows:

- With all modelled new entry wind farms in Queensland in service and operating at full installed capacity, Queensland to New South Wales power transfer of 1,400 MW on the QNI demonstrated adequate damping performances of the inter-area modes of interest in the NEM as required by clause S5.1.8 of the NER.
- Under system-normal conditions, transient stability limits for a Bulli Creek fault or a Boyne Island potline trip appeared to be more limiting than a 1,400 MW oscillatory stability limit. The transient stability limit is in the region of 1,100 MW to 1,300 MW, so that the QNI oscillatory stability limit will not be material until this transient stability limit is increased above 1,400 MW.

5.4.2 South Australia to Victoria oscillatory stability limit on Heywood and Murraylink

Worst case scenario studies were undertaken with low system demand in South Australia, high wind generation, high export to Victoria, and with a minimum number of synchronous generators online. AEMO undertook time domain analysis, simulating an LLG fault on the South East – Tailem Bend 275 kV line, cleared in 100 ms and 120 ms from near and far ends respectively, with and without the Para SVCs' Power Oscillation Damper (POD) in service.

Key findings of this investigation are summarised as follows:

- With at least six synchronous generating units in service in South Australia (including Northern Power Station), South Australia to Victoria power transfer of 870 MW provided by all existing wind farms in South Australia operating at full installed capacity, and all modelled new wind farms in South Australia operating up to 75% of their installed capacities, adequate damping performances of the inter-area modes of interest in the NEM was demonstrated (namely I25, I35 and QNI modes), as required by clause S5.1.8 of the NER.
- Under some study conditions, reduced output of wind generation was required because of oversupply conditions. I.e., insufficient demand in South Australia and export capability from South Australia to Victoria to allow operation of all 2020 wind generation at full output in combination with the minimum load levels of the selected synchronous generating units.
- With less than six synchronous generating units in service in South Australia, dynamic simulation problems and network convergence issues relating to reactive capability were encountered. The reactive capability issues appeared to be more critical than oscillatory instability under these extreme operating scenarios. Further work is required to identify oscillatory stability limits to South Australian system operation with very high levels of wind generation.

CHAPTER 6 - REGIONAL SUMMARIES

This report identifies a number of potential power system impacts arising from high levels of wind generation in the National Electricity Market (NEM). It identifies a range of options to manage some of these.

Many of the impacts identified in this report are tied to the location and size of the assumed wind generation connections by 2020. The actual impacts will depend somewhat on the actual wind generation built. However, some general comments can be made for different regions of the NEM; these are summarised in this chapter.

6.1 Tasmania

AEMO's studies suggest that a number of operational impacts can arise from increased wind generation in Tasmania, principally around control of power system frequency following contingency events. These include:

- Lower power system inertia, caused by economic displacement of other generation by wind, can increase the requirement for contingency FCAS to ensure adequate control of power system frequency. Limits on the output of wind generation and Basslink transfers may be required under some operating conditions to ensure that contingency FCAS requirements remain within manageable limits.
- An update to the calculations used to determine contingency FCAS requirements in Tasmania is required to ensure the response of wind generation and the Basslink HVDC Interconnector to power system disturbances is correctly considered in these calculations.
- Higher rates of change of frequency (RoCoF) may occur in Tasmania following contingency events, again due to lower power system inertia due to economic displacement of other generation by wind. AEMO notes that Transend has already advised the need for limits on the output of existing wind generation at Musselroe, and on imports on the Basslink Interconnector to ensure that RoCoF levels remain within acceptable limits in Tasmania. Increased wind generation in Tasmania will potentially increase the period of time when AEMO may need to limit wind generation output and Basslink transfers to manage RoCoF within acceptable limits.
- The requirement for regulation FCAS in Tasmania may increase. This is due to an overall increase in the un-forecasted five-minute variability in wind generation output. AEMO expects this increased requirement can be managed within existing frequency regulation arrangements.
- Displacement of conventional synchronous generation by wind has the potential to reduce power system fault levels in Tasmania, particularly at busses with normally high fault levels due to major nearby synchronous generation. This may affect the operation of the Basslink Interconnector, and the operation of wind generation itself.
- A significant reduction in Tasmanian demand, particularly minimum demand levels, would increase the challenges of operating the Tasmanian power system. Lower demand levels would require less synchronous generation online during high wind periods, increasing the challenges around inertia and frequency control following contingencies.

To manage these impacts under a business-as-usual approach, AEMO may need to curtail Basslink transfers and wind generation in Tasmania. This would ensure dispatch of sufficient other synchronous generation to allow adequate control of power system frequency, and ensure adequate power system fault levels.

The actual amount of curtailment of 2020 wind generation required would depend significantly on the operational behaviour of other generation in Tasmania, particularly during periods of low Tasmanian demand and high output from wind generation, when curtailment would most likely be required.

6.2 South Australia

South Australia currently has the highest penetration of wind generation in the NEM, and these studies assume that South Australian wind generation will further increase by 2020. This increase results in potential operational impacts around control of power system frequency following contingency events resulting in separation of the South Australian power system from the rest of the NEM. AEMO notes the following:

- There is sufficient wind generation modelled to supply all demand in South Australia and export from South Australia to Victoria at maximum capacity under lower demand conditions, potentially resulting in no requirement for any synchronous generation online in South Australia to meet the supply–demand balance. Curtailment of wind generation may be required due to insufficient South Australian load and export capability.
- Economic displacement of other forms of generation by wind in South Australia can reduce power system inertia in South Australia, and displace some or potentially all local generation that is capable of controlling frequency within South Australia. Generation located at only four power stations in South Australia is currently registered to provide FCAS.
- South Australia is connected to the rest of the NEM by approximately 640 km of double-circuit, single-tower AC transmission line. For the last three years, planned outages of some portion of this AC transmission connection have resulted in South Australia being at risk of single contingency separation from the rest of the NEM for between 8% and 18% of the year.

  Two actual separation events where South Australia became disconnected from the NEM occurred during this period, both due to credible contingency events during planned outages. Increased wind generation will increase the challenge of ensuring that the South Australian power system can survive these separation events in a controlled manner, and that frequency can continue to be controlled in the islanded South Australian region.
- Immediately following separation from the NEM, high levels of RoCoF may already occur in South Australia with existing levels of wind generation, particularly during periods of low power system inertia in South Australia. At present, AEMO is seeking further information to determine acceptable limits on RoCoF in South Australia to ensure correct operation of key control systems (such as under-frequency load shedding).
- The calculations used to determine contingency FCAS requirements in South Australia under conditions of potential or actual separation from the rest of the NEM need to be updated. They need to consider power system inertia in South Australia, and the response on wind generation to power system disturbances.

AEMO may need to curtail the output of wind generation in South Australia to ensure adequate control of power system frequency, particularly during conditions of potential or actual separation from the rest of the NEM. The level of any potential curtailment required depends significantly on the operational behaviour of other generation in South Australia, particularly during periods of low power system demand and high wind generation.

While limits to RoCoF in South Australia are not yet fully understood, in the absence of other changes, it may also be necessary to take action to ensure minimum levels of synchronous generation remain online in South Australia at all times, not just during periods of potential credible separation from the rest of the NEM. This will ensure RoCoF in South Australia remains within required limits.

6.3 Victoria

These studies model nearly 5 GW of wind in Victoria by 2020, which is above the region’s predicted minimum demand levels. As the Victorian region is strongly interconnected with other NEM regions, issues related to frequency control are not expected to be material.

Studies undertaken for this report suggest the potential for reductions in existing Victorian interconnector transfer limits, particularly those based on transient stability. The reductions modelled in these studies were due to the reduced inertia of generation in Victoria and South Australia due to displacement by high levels of wind generation, and the response to disturbances of large amounts of closely connected wind generation.

The changes modelled in these studies have the potential to limit export from Victoria to New South Wales, which may in turn require curtailment of wind generation due to the combined supply of wind generation in Tasmania, South Australia and Victoria exceeding their combined available load and export capability. This would be most significant during periods of minimum power system demand, and high output from wind generation.

Determining the actual impacts of new wind generation on interconnector transfer limits will require accurate modelling information about the actual dynamic performance of future wind generation projects, as well as knowledge about project size and connection points.

6.4 New South Wales

These studies model around 2.4 GW of wind generation in New South Wales by 2020.

No limits to increased wind generation related to frequency control and inertia were identified, due to the strong interconnection of the New South Wales power system with adjacent regions, and the amount of synchronous generation that would need to remain online in New South Wales to satisfy the supply–demand balance.

Some impacts on New South Wales interconnector capability were identified with increased wind generation; these depend on the size, location and assumed capability of the new wind generation. In some cases there were increases in existing interconnector limits identified with increased levels of wind generation.

6.5 Queensland

This report identifies relatively few impacts in Queensland, as the projected levels of wind generation there are small relative to the amount of conventional synchronous generation that will remain in this region. Relatively little change is expected from power system operation as seen today.

Some potential impacts in QNI Interconnector capability were identified, based on assumed development of new wind generation near this interconnector.

CHAPTER 7 - MARKET SIMULATION RESULTS

This chapter presents the results of market simulations conducted to inform and quantify the power system impacts presented in the previous chapters of this report. Market modelling is able to explore how changing demand and wind resource availability affects the economic dispatch of the National Electricity Market (NEM) at hourly resolution. This can be used to identify the potential impacts on network congestion and generator utilisation over the course of a full year.

A range of studies were conducted using assumptions consistent with AEMO's 2012 National Transmission Network Development Plan (NTNDP) planning scenario[35] for the 2020–21 financial year. The business-as-usual simulation results for 2020–21 were coupled with several sensitivity studies to examine issues such as operation of generation under low demand and high wind conditions, or separation of South Australian from the NEM.

AEMO's market modelling considered network limits and resulting congestion related to thermal network loading, and voltage and transient stability limits, considering the output of both existing and new wind generation,

AEMO's market modelling did not directly incorporate newly identified operational limits related to power system frequency control and inertia or to power system fault levels; and did not directly quantify the impact on energy output from wind generation due to these particular operational limits. AEMO assessed these particular limits by "post processing" the market modelling generation dispatch outputs, in order to quantify period of time for which these particular limits may occur.

The modelling was not intended to directly explore the need for additional transmission investment or market (price) impacts. Further details on the modelling methodology and assumptions are described in Section 8.2.

7.1 Key findings

AEMO's 2012 NTNDP forecast 8.9 GW of new wind generation investment by 2020–21, bringing total installed wind generation across the NEM to around 11.5 GW.

Integrating this level of additional wind generation into the NEM presents challenges for system operation, particularly when existing synchronous generation is economically displaced at times of lower demand.

Frequency control and inertia

Potential frequency control and inertia impacts of increased wind generation were typically assessed using two scenarios:

- An "optimistic", high-inertia dispatch scenario, where minimum generation limits on generation were rigidly enforced, meaning this minimum generation output was always fully dispatched in preference to wind generation.
- A "pessimistic", low-inertia dispatch scenario, where wind is always fully dispatched ahead of all synchronous generation. This scenario assumes that all plant is capable of operating flexibly over its entire operating range.

Neither scenario is entirely realistic, with actual operational outcomes likely to lie between these two extremes.

Analysis of the simulated market dispatch during periods of high wind generation and low demand suggests that frequency control issues arising from low power system inertia levels may become an important issue for Tasmania and South Australia. In particular the market modelling showed that:

[35] AEMO, 2012 NTNDP Assumptions and Inputs. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs. Viewed: 29 July 2013.

- Simulated Tasmanian system inertia fell below acceptable[36] levels for 30-40% of the 2020–21 year, assuming a pessimistic, low-inertia dispatch.
- Simulated South Australian system inertia fell below acceptable[37] levels for 30% of the 2020–21 year, again assuming a pessimistic, low-inertia dispatch scenario.
- Both Tasmania and South Australia have acceptable levels of inertia throughout the year if synchronous generation is assumed to be always dispatched to its minimum stable levels ahead of wind generation. However, this assumption is likely to be optimistic, given that wind generation is likely to drive some synchronous generators offline rather than having them run at their minimum stable level and face extended periods of low or negative spot prices. How synchronous plant is operated during periods of low demand and high wind is key to some of the outcomes of this market modelling.
- The heavily interconnected nature of the Victorian region minimises the likelihood of any need to curtail wind generation in this region due to frequency control issues.
- Wind generation in New South Wales and Queensland was not sufficient to displace material amounts of thermal generation, resulting in no impact on power system frequency control in these regions.

Contingency FCAS requirements

AEMO made an assessment of contingency frequency control ancillary services (FCAS) requirements using the market modelling outputs. This analysis confirmed limitations in the current calculation of contingency FCAS requirements that will require some changes.

In particular, the current calculations of contingency FCAS requirements for the mainland assume that relatively high levels of generation inertia are always available. However, as identified above, these assumptions may no longer apply in South Australia, where substantial increases in wind penetration are projected. Accordingly, calculating contingency FCAS requirements in South Australia must consider power system inertia levels in future for conditions where South Australia may become, or is actually, separated from the rest of the NEM.

Under pessimistic assumptions, where wind generation is modelled as being fully dispatched ahead of synchronous generation, the results showed contingency FCAS requirements in both South Australia and Tasmania to be significantly higher than presently procured levels. At times, this resulted in potentially infeasible requirements in these regions.

AEMO may need to use constraint equations in the central dispatch process to ensure that contingency FCAS requirements remain manageable. This may require a reduction in maximum generation contingency size through the central dispatch process, limits on interconnection flows, or curtailment of wind generation output.

Market modelling suggests this could be required up to 25% of the time in Tasmania, and 60% of the time during the periods when South Australia is considered at risk of separation from the NEM.

Power system fault levels

High levels of wind generation also have the potential to increase or decrease power system fault levels by adding to the fault current contribution of existing synchronous generation at high demand periods, or by displacing existing synchronous generation during low demand periods.

Fault levels were assessed using power system study cases derived from hourly market modelling generation dispatch data. The modelling results show that:

[36] This assessment assumes a minimum 3,000 MW.s to 4,000 MW.s inertia requirement, based on both operation experience around contingency FCAS requirements in Tasmania, and recent limit advice from Transend to prevent under-frequency load shedding for credible contingencies with high rate of change of frequency impacts.

[37] This assessment assumes a minimum 4,000 MW.s inertia requirement, representing both a conservative estimate of inertia required to maintain RoCoF within manageable limits for a credible contingency resulting in separation of South Australia (250 MW), and an optimistic estimate of inertia required under non-credible loss of Heywood at full transfer (650 MW).

- Large reductions in fault levels could occur at locations that are electrically close to existing generation that may be displaced by wind generation.
- Far smaller variations in fault levels are observed for electrically remote areas. This suggests that fault levels at more remote wind generation connection points cannot be readily managed by controlling generation dispatch of in other parts of the transmission system. If increased fault levels are required at remote locations, this must be managed through local arrangements.
- In Tasmania, modelled George Town 220 kV fault levels fell below the levels required for high transfers on Basslink for up to 60% of the year in 2020–21 in some scenarios, potentially requiring either measures to increase fault level, or the curtailment of Basslink transfers.

Curtailment due to network limitations

A review of simulated wind generation output for each region compared to its full potential generation (based on wind capacity traces) showed that wind generation should be able to produce to its full potential capacity in Tasmania, New South Wales, and Queensland during 2020–21, when considering the network limits included in the market modelling.

However, the review showed the need for significant wind generation curtailment in the Victorian and South Australian regions. In particular:

- Total reduction in wind output of around 5,750 GWh in Victoria and 1,260 GWh in South Australia was modelled due to a combination of thermal constraints, oversupply, and interconnector transfer limits based on power system stability.

This information may provide locational signals for new wind farm investors, or suggest the need for work to address the identified network limits, to allow greater output from wind generation in these areas.

The following sections explore these findings in greater detail, focusing on four key result areas:

- Frequency control and inertia (Section 7.2).
- Contingency FCAS requirements (Section 7.3).
- Fault levels (Section 7.4).
- Interconnector capability and other findings (Section 7.5).

7.2 Frequency control and inertia

7.2.1 Introduction

A generating unit's inertia is a characteristic of its mechanical size and design. Inertia does not vary with unit output (providing the output is non-zero), and plays a fundamental role in the power system's response to frequency disturbances. In particular, inertia is key to determining how rapidly power system frequency can increase or decrease following a contingency event; in other words it is key to determining the power system's rate of change of frequency (RoCoF).

This study assumes that wind generation provides no inertia to the power system[38], so displacement of synchronous (inertia-providing) generation by wind generation reduces overall power system inertia. This effect is most prominent during periods when wind forms a large percentage of the generation mix, which will typically occur during periods of low demand and high wind speed when the requirement for non-wind generation to meet demand is minimal.

Current power system frequency control arrangements on the mainland assume sufficient power system inertia is always present to limit RoCoF to low enough levels that inertia does not need to be considered when determining FCAS requirements.

[38] See Section 3.3.2 for more details.

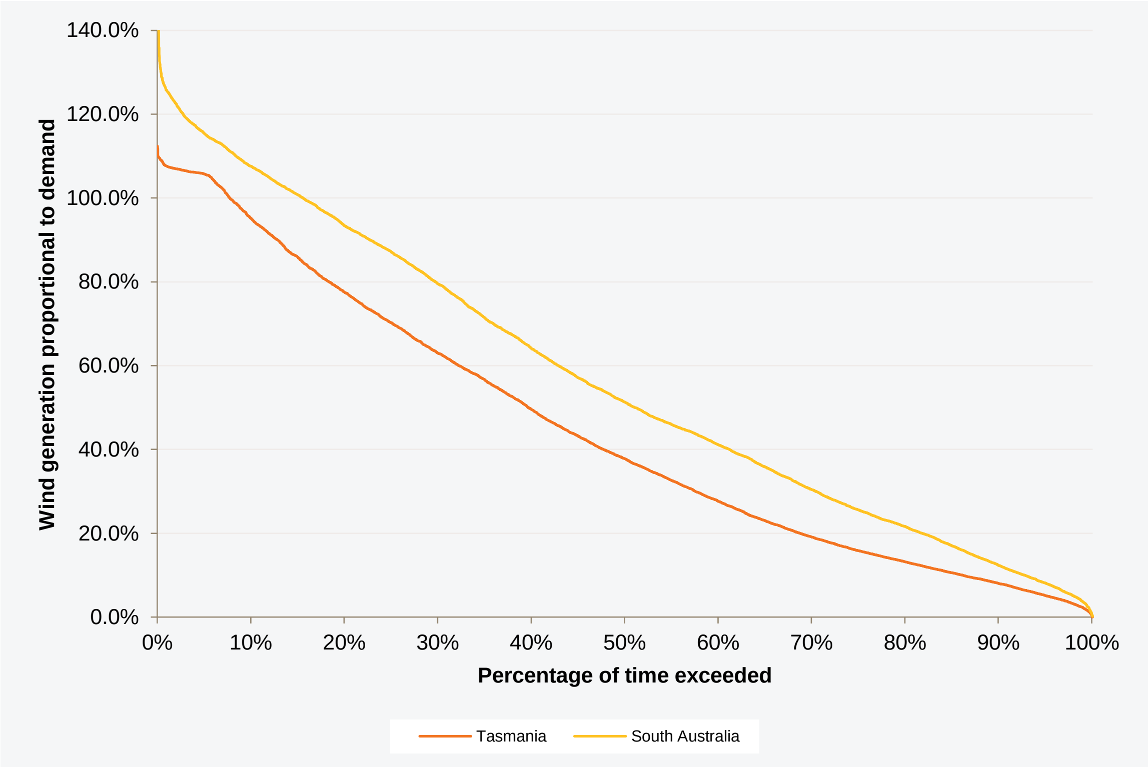
As wind generation increases, these assumptions may no longer be valid, particularly in a region such as South Australia that may become separated from the rest of the NEM, and where wind can form a large percentage of the generation mix. Taking inertia into account when calculating contingency FCAS requirements can lead to much higher requirements than current calculations. This is evident in Tasmania, where inertia is already considered in FCAS requirement calculations due to its low power system inertia.

The 2020–21 generation scenario used in this study provides sufficient wind generation to meet a considerable portion of low demand periods in Tasmania and South Australia.

Figure 7-1 shows wind generation as a percentage of demand for an “optimistic” high-inertia scenario, which assumes that minimum generation levels from conventional generation will always be dispatched ahead of wind generation. This results in a number of synchronous units effectively being “constrained on” for long periods of time, and relatively high levels of power system inertia.

In this optimistic high-inertia scenario, wind generation output exceeded demand for approximately 17% of the year in South Australia and 8% of the year in Tasmania. These figures would increase in a “pessimistic” low-inertia scenario which allowed wind to fully displace synchronous generation at all times.

Figure 7-1 — Wind generation as a percentage of regional demand, 2020–21, optimistic scenario



Modelled amounts of wind generation in New South Wales and Queensland are not sufficient to displace large amounts of synchronous generation, and no significant depression of power system inertia was evident in these regions. As a result, discussion in this section is limited to inertia in Victoria, South Australia and Tasmania.

Supplying the entire load of South Australia or Tasmania using wind generation would effectively reduce power system inertia to zero in those regions. Under such conditions, AEMO would be unable to ensure that power system frequency remained within the Frequency Operating Standards requirements at any time in Tasmania, or following separation of South Australia from the rest of the NEM.

A business-as-usual method to ensure AEMO could control power system frequency within requirements would be to use constraint equations in the central dispatch process. These equations would curtail wind generation, or other inertia-less supply sources, to ensure that sufficient synchronous generation remains online to allow adequate control of power system frequency.

Such constraint equations were not included directly in the market modelling; however, by analysing the market modelling outputs, AEMO was able to examine the frequency with which such constraint equations might be required. This is presented in Section 7.2.2 and Section 7.2.3.

This post-processing analysis of simulated market dispatch can provide high-level insight into the amount of wind generation curtailment that may potentially be required if business-as-usual approaches to frequency management based around the use of constraint equations in the central dispatch process continue to be used.

Minimum generation limits

Thermal generation units typically have a minimum stable generation output that can be sustained, due to their physical design and capability. Hydro generating units may also require minimum levels of generation due to hydrological issues or minimum river flow requirements. Modelling these minimum generation limits as part of the market modelling is critical to the outcomes presented in this section.

AEMO's standard market modelling assumes[39] that all generation between zero and a unit's minimum stable operating point is offered for dispatch at zero price. This is considered a reasonable approximation to reality, where negative offer prices for minimum generation levels are typical. It is often less costly for plant (particularly less flexible thermal plant) to continue generating at minimum load during short periods of low or negative spot prices, rather than shut down and restart.

However, with high wind penetration, this behaviour is unlikely to be economically sustainable, as thermal generation would need to operate for long periods where the dispatch price is likely to be very low or negative.

In reality, it is likely that some of these units would shut down for extended periods, based on commercial unit commitment costs and pressures that are neither publicly available nor readily predictable using market modelling with generation dispatch based on short-run marginal cost.

7.2.2 Tasmanian inertia

Minimum inertia requirements

Based on recent limit advice from Transend[40], under-frequency load shedding (UFLS) could potentially occur in Tasmania for single credible contingency if RoCoF was allowed to exceed critical levels. New constraint equations have recently been developed for Tasmania to prevent this. The constraint equations will limit import into Tasmania on Basslink and limit the output of the semi-scheduled Musselroe Wind Farm, to ensure RoCoF in Tasmania remains below levels that may result in UFLS for single credible contingency events.

While not directly designed to do so, these new constraint equations effectively limit minimum inertia in Tasmania to between 3,000 MW.s and 4,000 MW.s; a level which AEMO has also historically understood to be a minimum requirement for sufficient control of frequency following contingencies with existing frequency control arrangements.

For the purpose of subsequent analysis, 3,000 MW.s to 4,000 MW.s is used to represent the boundary between acceptable and unacceptable levels of inertia for Tasmania in 2020–21.

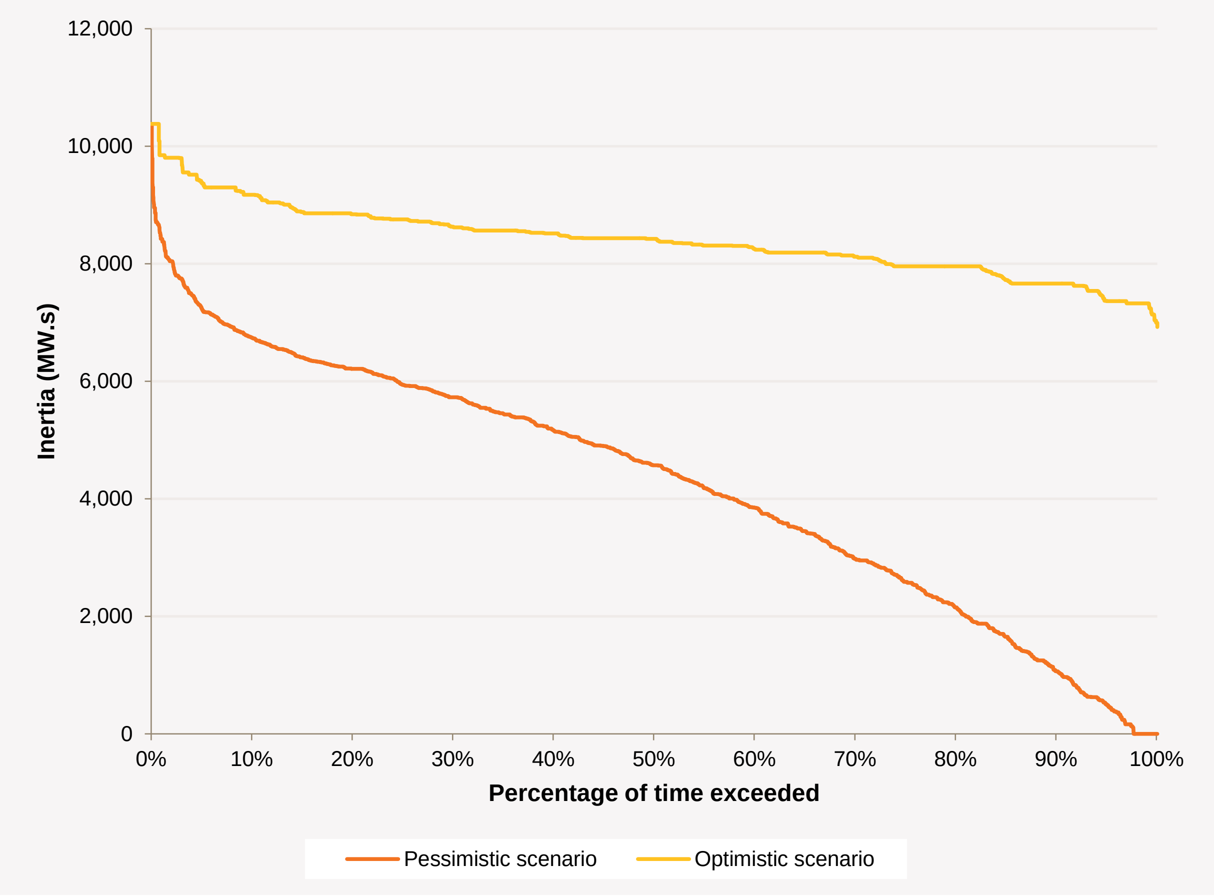
Simulated inertia outcomes

The modelling suggests that with high levels of wind generation, reduced system inertia may be an important issue in Tasmania.

Figure 7-2 shows modelled inertia in Tasmania in 2020–21 under and optimistic, high-inertia scenario, and a pessimistic, low-inertia scenario. The pessimistic scenario presented here also included modelling of permanent shutdown of a large industrial load (modelled at the request of Transend to present a worst case scenario).

[39] AEMO. 2013 Planning Assumptions. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/2013-Planning-Assumptions.
[40] Advice was supplied after market modelling had commenced for this study, and is not considered in the market modelling.

Figure 7-2 — Simulated Tasmanian inertia duration curve, 2020–21



This figure shows the impact of rigidly maintaining minimum output levels from the existing synchronous generators in market modelling (optimistic scenario). This modelling results in inertia increases of up to 7,000 MW.s compared to cases where wind is dispatched ahead of other forms of generation.

The likely outcome for inertia levels in Tasmania would lie somewhere between the two results shown; however, based on discussion with Transend, the scenario without minimum generation enforced (pessimistic scenario) is closer to the likely actual behaviour of the system.

The simulated inertia shown in Figure 7-2 can be compared with actual historical Tasmanian inertia, as shown in Figure 3-3. AEMO notes that the lowest inertia levels achieved in the optimistic scenario are higher than the inertia levels already seen in Tasmania.

Assuming an acceptable inertia requirement of 3,000 MW.s to 4,000 MW.s, the Tasmanian system inertia falls below acceptable levels for 30% – 40% of the time. This indicates the percentage of time when curtailment of installed wind generation and/or Basslink imports into Tasmania may be required in 2020–21 to ensure adequate inertia and control of power system frequency.

Dispatch constraint equations that limit the output of Tasmanian wind generation and Basslink imports are one way to ensure that sufficient Tasmanian inertia is maintained during these periods. Other options for managing issues around low power system inertia and control of power system frequency in Tasmania were identified in Section 3.7, and include, but are not limited to:

- Limiting effective contingency size, either through the central dispatch process or using control schemes.
- Modifying UFLS systems to allow operation with higher RoCoF levels.
- Providing a ‘synthetic’ inertial response from wind generation, or other power electronic devices.

- Operating existing generation in synchronous condenser mode to increase system inertia.
- Constructing dedicated synchronous condensers in Tasmania to increase system inertia.

7.2.3 South Australian inertia

Minimum inertia requirements

AEMO is required to ensure that frequency in South Australia can be managed within the Frequency Operating Standard requirements for both credible and non-credible contingency events. The most critical events for control of frequency are those that result in separation of South Australia from the rest of the NEM.

Sufficient inertia is also required in South Australia to ensure RoCoF remains within acceptable limits—based on the capability of connected generation—and on the performance of other connected equipment and control schemes such as UFLS.

While no system limits for RoCoF are currently defined for South Australia, an initial estimate of a minimum system requirement can be made based on the RoCoF that transmission-connected generating units may be required to withstand as part of their agreed performance standards.

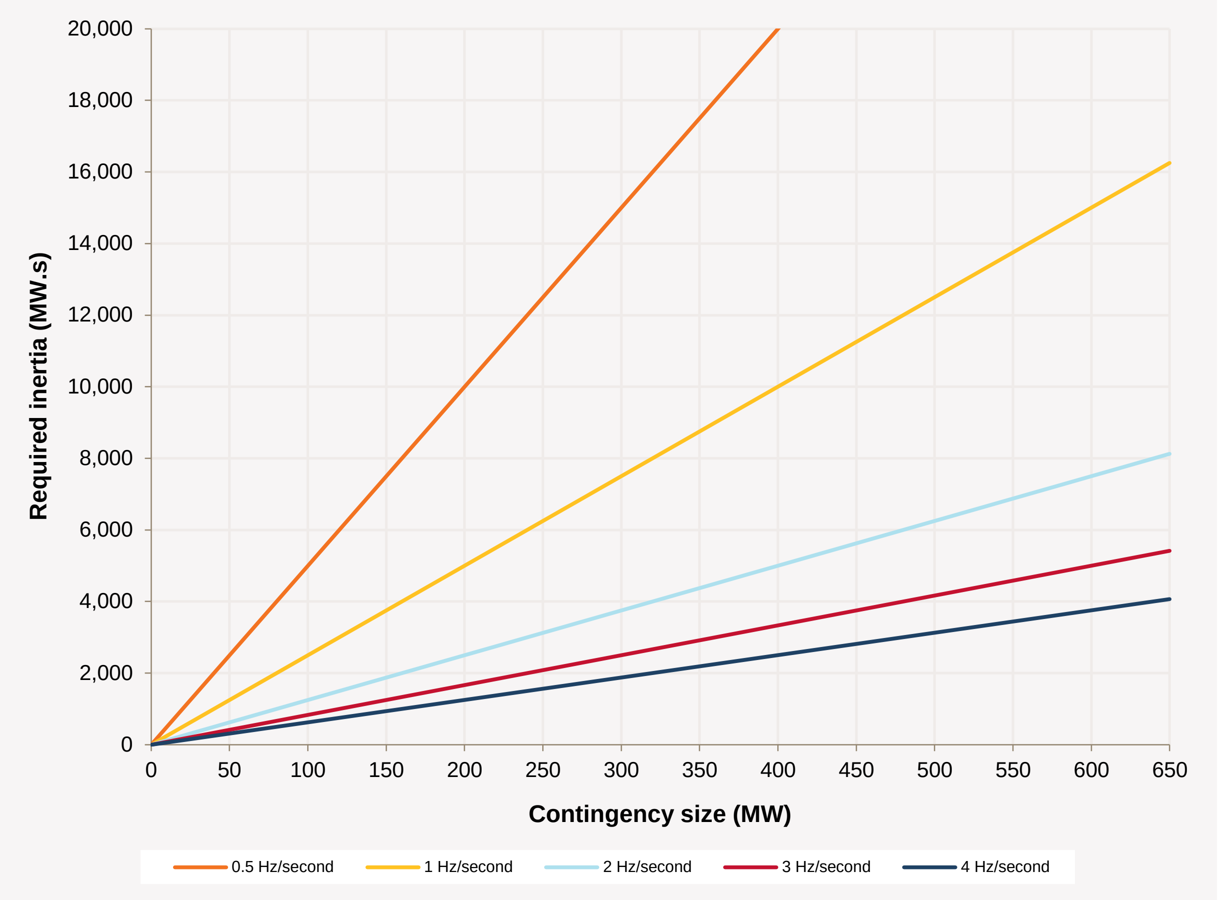
The automatic access standard for new generation connections is defined in Schedule 5.2.5.3 of the National Electricity Rules.[41] This specifies the response for automatic access as withstanding a RoCoF of 4 Hz per second for a period of 0.25 seconds. The minimum access standard specifies a RoCoF of 1 Hz/s for a period of one second. All new generation connections over 5 MW must at least meet this minimum requirement.

This analysis assumes an upper possible bound of 4 Hz/s, as any generator would be able to disconnect if RoCoF exceeded this level without risking non-compliance with the automatic access performance standards. Such events could result in widespread tripping of large generating units and associated supply disruption. This analysis considers a lower bound of 1 Hz/s, as transmission-connected generators must meet this minimum criterion for connection. For the purpose of this analysis, critical control schemes are assumed to operate correctly within the above range.

Figure 7-3 shows the relationship between RoCoF immediately after a contingency event, contingency size, and power system inertia.

[41] AEMC. 'National Electricity Rules'. Available: http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html. Viewed: 28 July 2013.

Figure 7-3 — Relationship between instantaneous RoCoF, contingency size, and system inertia



Assuming an allowable system RoCoF range of between 1 and 4 Hz/s:

- A credible contingency event, such as separation of South Australia with the Heywood Interconnector exporting or importing at 250 MW[42], yields a minimum inertia requirement of between approximately 2,000 MW.s and 6,000 MW.s.
- A non-credible contingency, such as the loss of the Heywood Interconnector at its full upgraded capacity of 650 MW, yields a minimum inertia requirement of between approximately 4,000 MW.s and 16,000 MW.s.

AEMO observed that inertia in the South Australian region drops as low as 4,000 MW.s when both Northern Power Station units were offline in early 2013. Historical power system inertia levels in South Australia can be seen in Figure 3-4. This suggests that even with existing levels of wind penetration in South Australia, power system inertia can already reach levels that can result in high levels of RoCoF.

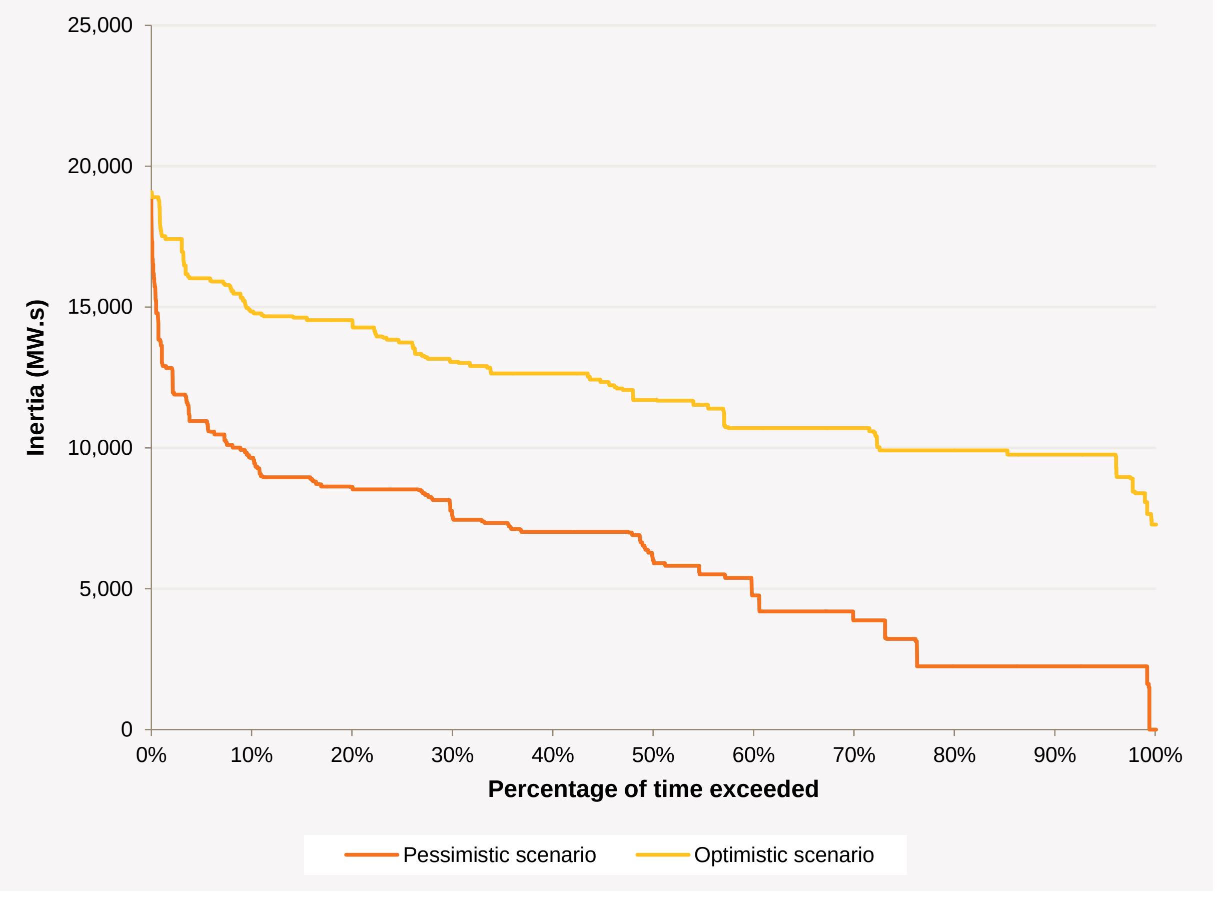
This analysis assumes that a minimum power system inertia of 4,000 MW.s is required in South Australia. This is assumed to represent the level below which AEMO may experience difficulties controlling power system frequency within the Frequency Operating Standards requirements for both credible and non-credible contingency events, and maintaining RoCoF in South Australia within acceptable levels.

[42] The 250 MW limit is used operationally for conditions where South Australia is at credible risk of separation from the rest of the NEM. This has historically been determined as the largest contingency size that the South Australian system can withstand at the time of a separation event.

Simulated inertia outcomes

The modelling suggests that with high levels of wind generation, reduced system inertia may be an important issue in South Australia. Figure 7-4 shows modelled inertia in South Australia in 2020–21 under an optimistic, high-inertia scenario, and under a pessimistic, low-inertia scenario.

Figure 7-4 — Simulated South Australian inertia duration curve, 2020–21



This figure shows the impact of rigidly maintaining minimum output levels from existing synchronous generation. An inertia increase of up to 8,000 MW.s is seen in the optimistic high-inertia scenario, compared to the pessimistic, low-inertia scenario, where wind is dispatched ahead of all other forms of generation.

The likely outcome for inertia levels in South Australia would fall somewhere between the two results shown, depending on operational strategies and responses from existing thermal generation to the increased levels of wind generation.

This simulated inertia can be compared against actual historical inertia levels in South Australia, as shown in Figure 3-4. AEMO notes that the lowest inertia levels achieved in the optimistic scenario are higher than the inertia levels already seen in South Australia.

Figure 7-4 indicates that if thermal generation is rigidly dispatched to minimum levels ahead of wind (optimistic scenario), the modelled inertia does not fall below 7,500 MW.s. However, more realistic bidding and operational behaviour is expected to result in substantial wind being dispatched ahead of thermal minimum stable generation levels.

In the lower estimate, where all wind is dispatched ahead of thermal generation (pessimistic scenario), South Australian inertia levels are simulated to be below 4,000 MW.s for approximately 30% of the year. This provides an initial estimate of the period of time when curtailment of wind generation or other inertia-less generation may be required in South Australia to ensure sufficient power system inertia to maintain control of power system frequency within acceptable limits, particularly if considering both credible and non-credible contingency events.

There is significant uncertainty around this figure, as South Australian RoCoF limits are not well understood, and it is also unclear for what period of time these RoCoF limits would need to be managed. For the last three calendar years, AEMO's operational records indicate that South Australia has been at credible risk of separation for the NEM for between 8% and 18% of the year.

It may also be necessary to ensure RoCoF limits are managed following certain specified non-credible power system contingencies, to ensure the correct operation of key control schemes such as UFLS following non-credible contingency events. Further clarification is required around determining allowable RoCoF limits, and for what contingencies these RoCoF limits must be maintained.

Dispatch constraint equations could be applied to ensure that minimum levels of synchronous generation remain online. However, the actual impact of such constraints on the operation of wind generation is difficult to assess, as the relationship between the reduced output of wind generation and any corresponding increase in unit commitment and associated inertia from synchronous generation is not straightforward; there is a "lumpy" relationship between generating-unit commitment and power system inertia.

Such constraints would typically limit wind generation, particularly during periods of low demand and high wind speeds, when wind generation would be a large part of total generation in South Australia.

Other options for managing power system frequency, low power system inertia and high RoCoF issues in South Australia were identified in Section 3.7, and include:

- Limiting contingency size, either through the central dispatch process or using control schemes.
- Modifying under-frequency load shedding systems to allow correct operation with higher RoCoF levels.
- Providing a 'synthetic' inertial response from wind generation, or other power electronic devices.
- Operating existing generation in synchronous condenser mode – though the impact of this may be limited in South Australia where few existing generating units have this capability.
- Constructing dedicated synchronous condensers in South Australia to increase system inertia.
- Establishing incentives for thermal generation to remain in service to provide inertia, or other "non-energy" system services.

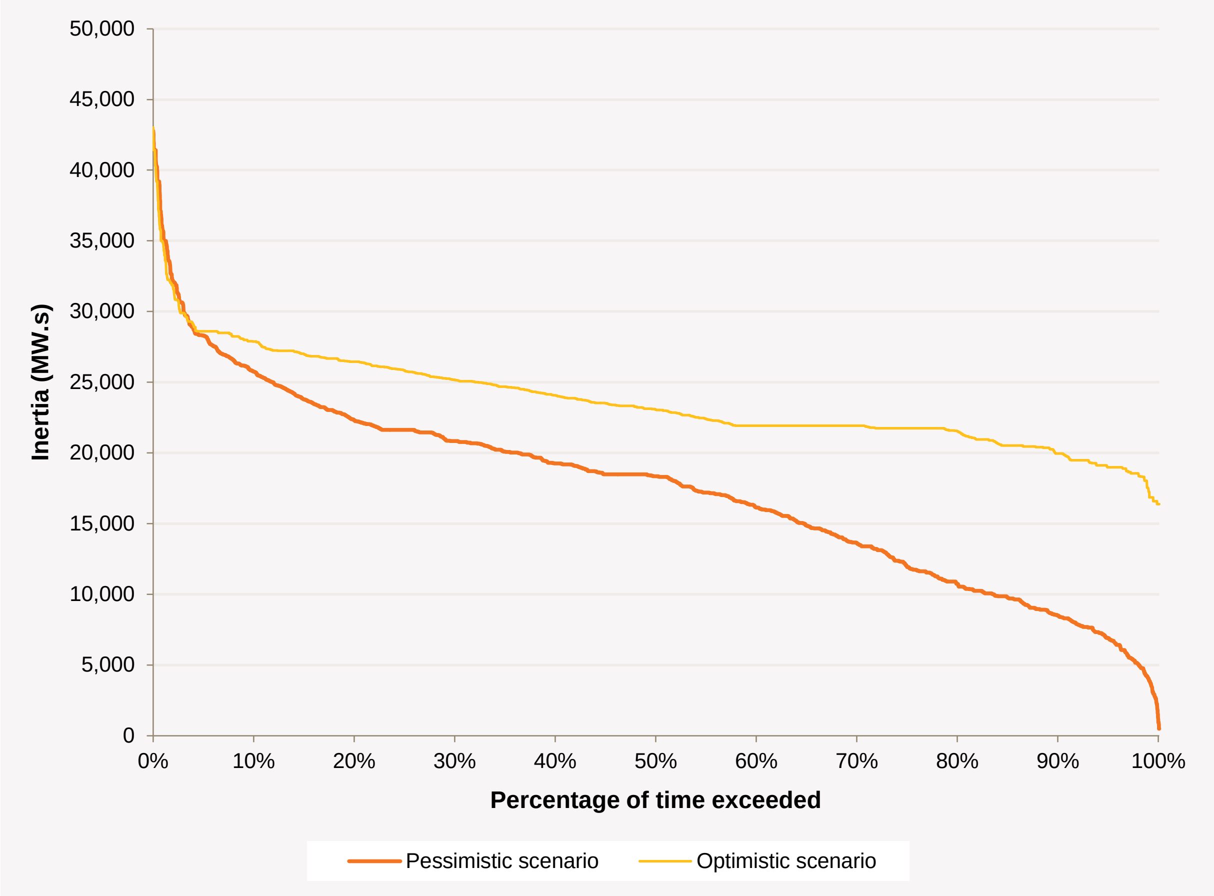
Arrangements to limit RoCoF levels using existing South Australian generating units could also involve incentives to encourage plant modification to allow operation at lower minimum load levels, or as synchronous condensers.

7.2.4 Victorian inertia

Figure 7-5 below shows simulated power system inertia in Victoria under the two modelling scenarios, a pessimistic scenario resulting in low power system inertia, and an optimistic scenario, resulting in higher power system inertia.

Again, this figure shows the impact of rigidly maintaining output from the existing synchronous generators in the optimistic scenario. It shows inertia increases of up to 10,000 MW.s, compared to the scenario where wind is dispatched ahead of all synchronous generation (pessimistic scenario). The likely outcome for inertia levels in Victoria would fall somewhere between the two results shown, dependent on changes in operational behaviour of existing thermal generation.

Figure 7-5 — Simulated Victorian inertia duration curve, 2020–21



The results indicate that with simulated 2020–21 levels of modelled wind generation in Victoria, there is potentially significant economic displacement of synchronous generation during some operating periods.

However, Victoria is strongly interconnected, so at times of high wind output in the southern states it is able to utilise supporting inertia from other NEM regions in addition to its own local inertia. As a result, low levels of power system inertia in Victoria alone will not directly impact mainland frequency control following contingencies.

Power system studies described in Chapter 5 - suggest that reduced local Victorian inertia levels could lead to reduced Victorian export limits to New South Wales based on transient stability.

7.3 Contingency FCAS requirements

On the mainland, requirements for contingency (FCAS) are calculated based on the size of the largest single credible contingency, and the change in system demand in response to changing system frequency (load relief).

Implicit in these current calculations is the assumption that system inertia is always high enough so that RoCoF does not need to be considered when determining contingency FCAS requirements.

Current calculations for Tasmanian contingency FCAS requirements already consider power system inertia, due to the relatively low inertia of the Tasmanian power system.[43]

Increasing penetration of low-inertia generation will potentially increase power system RoCoF levels, and increase requirements for contingency FCAS. This section explores how contingency FCAS requirements may be affected by reduced power system inertia, and the effects of including inertia in FCAS calculations. AEMO has assessed these changes in South Australia and Tasmania, as these are the two NEM regions where frequency control based on local inertia and islanded operation are most material.

Calculations in this section refer to contingency FCAS requirements for the six-second (containment) phase after an event. These are referred to as fast raise (R6) or fast lower (L6) contingency services (collectively, fast services). Other contingency FCAS requirements for 60-second (stabilisation) and five-minute (recovery) responses are not considered here.[44]

7.3.1 Calculating FCAS requirements

The calculation methodology for contingency FCAS requirements is described on AEMO's website.[45] On the mainland, contingency FCAS requirements are defined as the difference between the maximum credible contingency size, and the assumed load relief following the event.

Load relief

Load relief refers to changes in demand that results from system frequency changes, with the change in demand having a restorative effect on frequency: if an event causes system frequency to fall, demand also falls, providing a stabilising effect.

The amount of load relief that occurs depends on the load characteristics. On the mainland, demand is assumed to change by 1.5% for every 1% change in frequency. For Tasmania, demand is assumed to change by 1% for every 1% change in frequency.

The maximum permitted frequency change within a defined period is used to determine the load relief for that period, and the resulting FCAS requirement for that period. For example, the frequency band for single credible generator or load contingency events on the mainland allows for a frequency change of 0.5 Hz (1% of 50 Hz), leading to an assumed 1.5% change in demand for mainland frequency events. The difference between this assumed change in demand and the contingency size must be supplied as contingency FCAS.

Current calculation approach

Contingency FCAS requirements may be calculated with reference to the sudden loss of a generator (generation event), a load (load event), or a transmission system element (network event). Some transmission contingencies may result in one part of the power system becoming disconnected from the rest of the power system, referred to as a separation event.

[43] Available: http://www.aemo.com.au/Electricity/Policies-and-Procedures/System-Operating-Procedures/~/media/Files/Other/SystemOperatingProcedures/so_op3708av13.ashx. References in this document refer to Version 13, dated 20 March, 2012.
[44] For an introduction to ancillary services, see http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services.
[45] See footnote 43.

On the mainland, contingency FCAS requirements for generator and load events are calculated with reference to the entire interconnected system, because power system frequency and inertia are common variables across the entire power system. However, when one part of the system is separated from the rest, the separated load is smaller, so lower levels of frequency-dependent load relief are required; but the contingency risk may be unchanged, leading to higher contingency FCAS requirements.

For separation events, the contingency risk is loss of flow on an interconnector, with increasing interconnector flow resulting in increased requirements for contingency FCAS.

Inertia requirement

Current frequency standards require that frequency returns to within specified bounds once a prescribed amount of time after a contingency event has occurred. Low system inertia increases the RoCoF, and increases the challenge of controlling power system frequency within requirements. As a result, if power system inertia falls below certain critical levels, inertia must also be considered when determining contingency FCAS requirements.[46]

Calculations to determine contingency FCAS requirements while considering inertia are more complicated than the load or generation at risk assessments used in dispatch. They are solved using an iterative algorithm incorporating multiple frequency limits, load relief, demand and system inertia as parameters.

The results presented here consider hourly inertia values, as shown in Figure 7-2 and Figure 7-4, along with hourly regional demand considered in market modelling, and the relevant load relief and region-specific frequency limits to obtain hourly contingency FCAS requirements.

7.3.2 Separation of South Australia and contingency FCAS requirements

Credible contingency events that occur during planned outages can result in the separation of South Australia from the rest of the NEM. Transmission contingency occurring during planned outages anywhere along the 640 km connection between Moorabool in Victoria and Tailem Bend in South Australia, can result in separation.[47] Currently, under these conditions, maximum transfer on the Heywood Interconnector is limited to 250 MW.

Market modelling results were used to determine the contingency FCAS requirements in 2020–21 on an hourly basis. The scenario used limited Heywood interconnection flow to a maximum of 250 MW for every hour of the year, simulating conditions of potential separation of South Australia from the rest of the NEM.

This market modelling used a pessimistic generation dispatch scenario, where wind was always assumed to be dispatched ahead of all other generation in South Australia, resulting in the lowest power system inertia levels.

Fast lower (L6) contingency FCAS requirements were calculated, with a containment frequency of 52 Hz (4% change in frequency), as required by the South Australian Jurisdictional System Security Coordinator for this operating condition and contingency.

For separation events, local L6 contingency FCAS must be obtained entirely from local generation within South Australia during periods of power flow from South Australia to Victoria; this occurred approximately 58% of the time for this particular scenario.

AEMO does not currently obtain local L6 contingency FCAS when Heywood power flow is from Victoria to South Australia, as advised by the South Australian Jurisdictional System Security Coordinator for this operating condition. To control frequency within the Frequency Operating Standards requirements, UFLS may occur in South Australia for separation events during periods when South Australia is importing from Victoria prior to separation.

Figure 7-6 compares local South Australian contingency FCAS requirements between the current load relief only calculation, and the inertia-inclusive calculation, considering potential separation of South Australia. Note that

[46] See Section 3.3.3 for more details

[47] The Murraylink HVDC Interconnector may continue to provide a flow path between Victoria and South Australia during such events; however, it does not incorporate appropriate frequency control facilities to prevent the two regions' frequencies from drifting apart. For all practical purposes it appears as a generator or load to each region, depending on the direction of flow at the time of the event.

contingency FCAS requirements exceed the scale of this chart during periods when simulated South Australian inertia falls to zero, as inertia forms a denominator in contingency FCAS calculations that considered inertia.

Figure 7-6 — Fast lower contingency FCAS requirement for SA separation

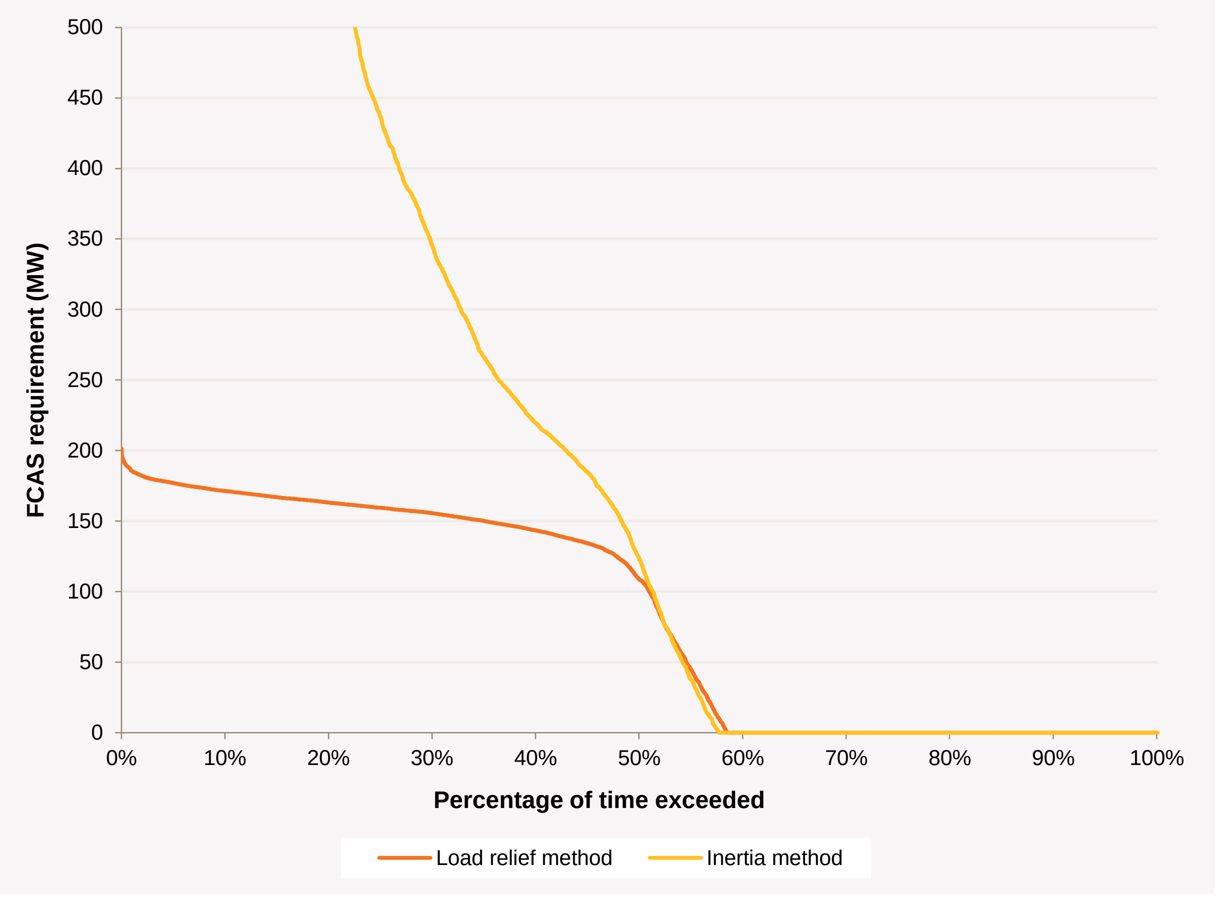


Figure 7-6 shows that for the majority of conditions where South Australia was required to obtain local L6 contingency FCAS, the more accurate requirement calculated considering power system inertia is higher than that calculated only considering frequency dependent load relief.

This clearly demonstrates AEMO needs to use the more accurate calculation of contingency FCAS requirements considering inertia in South Australia for these operating conditions, rather than the current approach which only considers frequency dependent load relief. AEMO is undertaking work to update this calculation.

Figure 7-6 indicates that, without intervention in the central dispatch process, contingency FCAS requirements could become unfeasibly large for the majority of the time when South Australia was exporting to Victoria during periods of risk of separation from the rest of the NEM.

AEMO notes that the contingency FCAS requirements shown in Figure 7-6 were not considered in the market modelling central dispatch process, as these requirements were determined using a post-processing approach after the market modelling was completed. Generation and interconnector dispatch was not adjusted in the market modelling to manage these contingency FCAS requirements. Under real conditions, power system dispatch outcomes would be adjusted to ensure that contingency FCAS requirements remained within available limits, most likely by limiting the export flows on the Heywood interconnection from South Australia towards Victoria below the 250 MW maximum limit for this condition.

AEMO assumed the maximum contingency FCAS available locally in South Australia to be limited to the currently registered 172 MW, as shown in Table 3-3; and that the real-time actual availability of the contingency FCAS service will vary with market conditions. Obtaining local contingency FCAS requirements within South Australia may be very difficult to achieve during these periods, particularly in an environment where the generators registered to provide these services are economically displaced by high levels of wind generation. Under these conditions, limitations on pre-contingent Heywood Interconnector flow may be required to keep the resulting local South Australian contingency FCAS requirements within manageable levels.

7.3.3 Contingency FCAS requirements in Tasmania

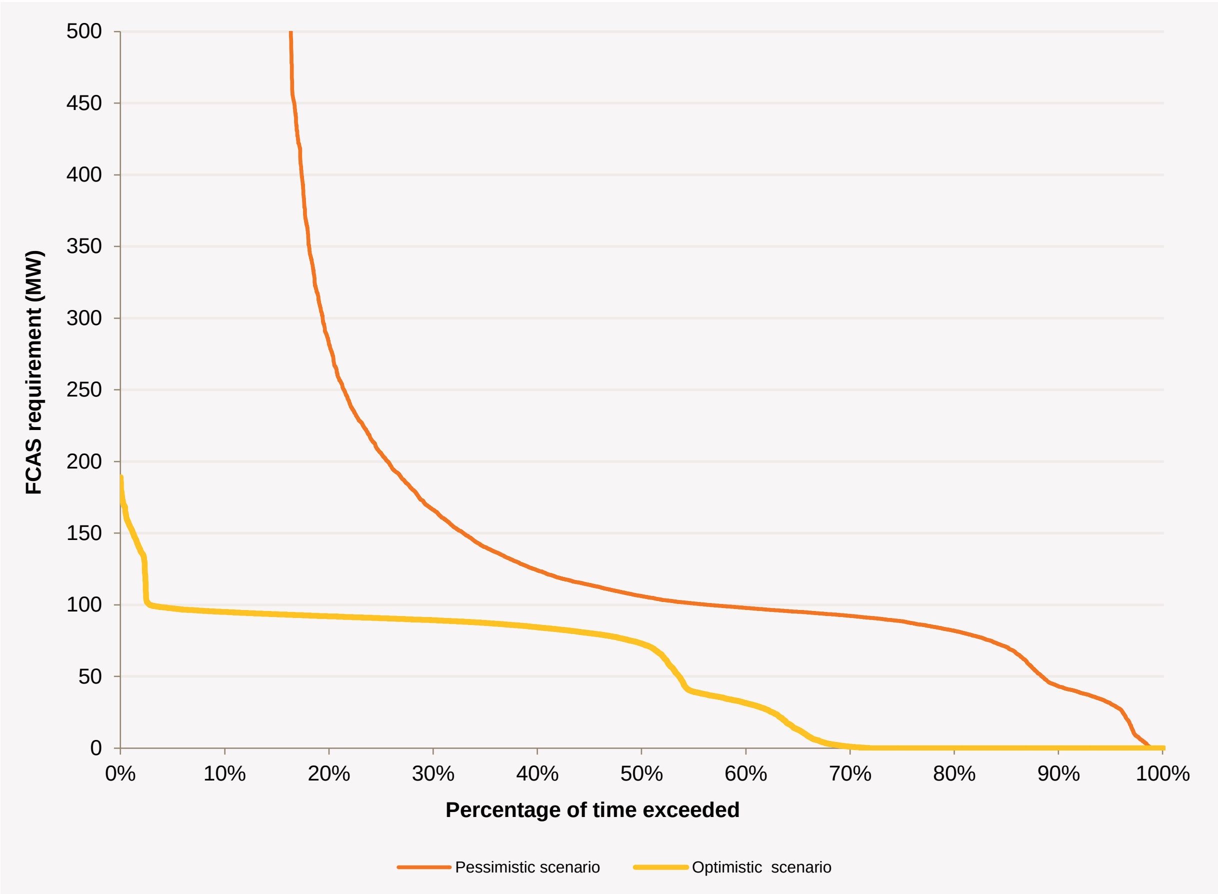
The modelled Tasmanian power system inertia, presented in Section 7.2.2, can be very low when minimum generation levels on synchronous plant are not rigidly enforced. In Tasmania, the highest requirements for contingency FCAS will occur at times when power system inertia is low, demand is low, and wind generation is supplying the largest proportion of demand.

As described in Section 3.5.3, power system frequency in Tasmania following loss of the Basslink HVDC interconnection is managed principally using a control scheme, and not through the use of contingency FCAS. This is in contrast to South Australia where a transmission contingency resulting in separation from the rest of the NEM is the critical contingency event for frequency control when local inertia is low.

Figure 7-7 shows the calculated R6 contingency FCAS requirement in Tasmania under the high-inertia (optimistic) and low-inertia (pessimistic) market modelling scenarios respectively. These two scenarios differ significantly in the resulting power system inertia, due to the modelling of minimum generation limit dispatch ahead of wind generation.

The contingency considered in both scenarios is loss of the largest modelled generating unit in Tasmania, using the existing contingency FCAS requirement calculation that considers demand, contingency size and power system inertia.

Figure 7-7 — Fast raise contingency FCAS requirement for Tasmania in 2020–21



This figure clearly shows that under the pessimistic scenario, calculated requirements for contingency FCAS in Tasmania for 2020–21 are very large, and are likely to be infeasible for a significant proportion of the time.

If a requirement of 200 MW of R6 FCAS available to Tasmania is selected as a somewhat arbitrary upper feasible limit, then this limit would be exceeded approximately 25% of the time in the pessimistic scenario, potentially requiring intervention in the central dispatch process to manage power system security.

However, contingency FCAS requirements in the optimistic scenario are far more manageable, and are modelled as below this level for all simulations.

Note that the modelled R6 contingency FCAS requirements in these two scenarios can be compared to actual historical requirements, as shown in Figure 3-2.

The difference between the two scenarios in Figure 7-7 is driven by the modelling of operational behaviour of existing hydro and gas generation in Tasmania. This suggests that the actual operation behaviour of existing generation in Tasmania, and the resulting levels of future power system inertia are critical to the future likely requirements for contingency FCAS in Tasmania. As described in Section 7.2.2, the actual outcome is likely to fall between the two scenarios shown in Figure 7-7.

Curtailment of wind generation and Basslink imports into Tasmania to manage system inertia, or limitations on maximum generation contingency size, could also be used to ensure contingency FCAS requirements remained within feasible limits. A range of other potential options for managing power system frequency with high levels of wind generation were identified in Section 3.7.

7.4 Fault levels

The section explores the potential effect of high levels of wind generation on power system fault levels.

Chapter 4 - identifies that high levels of wind generation have the potential to both increase or decrease power system fault levels compared to existing levels, by adding contribution during high demand periods, or displacing other generation during low demand periods.

AEMO quantified these fault level outcomes using automatically generated power system loadflow cases, based on the hourly generation dispatch patterns from the market modelling studies.

In these assessments the fault current contribution from wind generation itself was not modelled; the calculated fault levels are only due to conventional synchronous generation. Effectively, these studies calculate the underlying electrical strength of the network to which the wind generation may be connecting.

AEMO calculated three-phase fault levels for a selection of geographically representative wind farm connection busses in Tasmania, South Australia, and Victoria. Due to the lower levels of wind penetration in New South Wales and Queensland (relative to existing synchronous generation), the effect of wind generation on fault levels there is expected to be considerably lower, and has not been examined further.

Fault levels have been calculated using a pessimistic, low-inertia scenario, and an optimistic, high-inertia scenario.

7.4.1 Tasmania

The Transend 2013 Annual Planning Report[48] (APR) provides both maximum and minimum existing fault levels for all busses in the Tasmanian system. Table 7-1 show the existing fault levels for the four Tasmanian busses where AEMO modelled new wind generation.

Table 7-1 — Fault levels for modelled Tasmanian busses

Bus	Maximum fault level (kA)	Minimum fault level (kA)
George Town 220 kV	12.8	2.7
Waddamana 220 kV	10.6	3.4
Burnie 220 kV	5.1	0.9
Derby 110 kV	2.8	1.5

While analysis was conducted for all four busses, two representative charts are included here for comparison. These show calculated fault levels for a bus electrically close to existing generation (George Town 220 kV—the Tasmanian connection point for the Basslink HVDC Interconnector), and for a more electrically remote bus, Derby 110 kV.

Figure 7-8 and Figure 7-9 present the calculated fault levels for the George Town 220 kV and Derby 110 kV busses respectively. These are based on simulated 2020–21 outcomes under the optimistic and pessimistic scenarios. A simulated 2012–13 scenario is also included for comparison, partly to confirm the utility of the modelling technique.

[48] Transend. Annual Planning Report. Available: http://www.transend.com.au/ournetworks/electricity/planning/annualreview/.

Figure 7-8 — Simulated George Town 220 kV fault levels

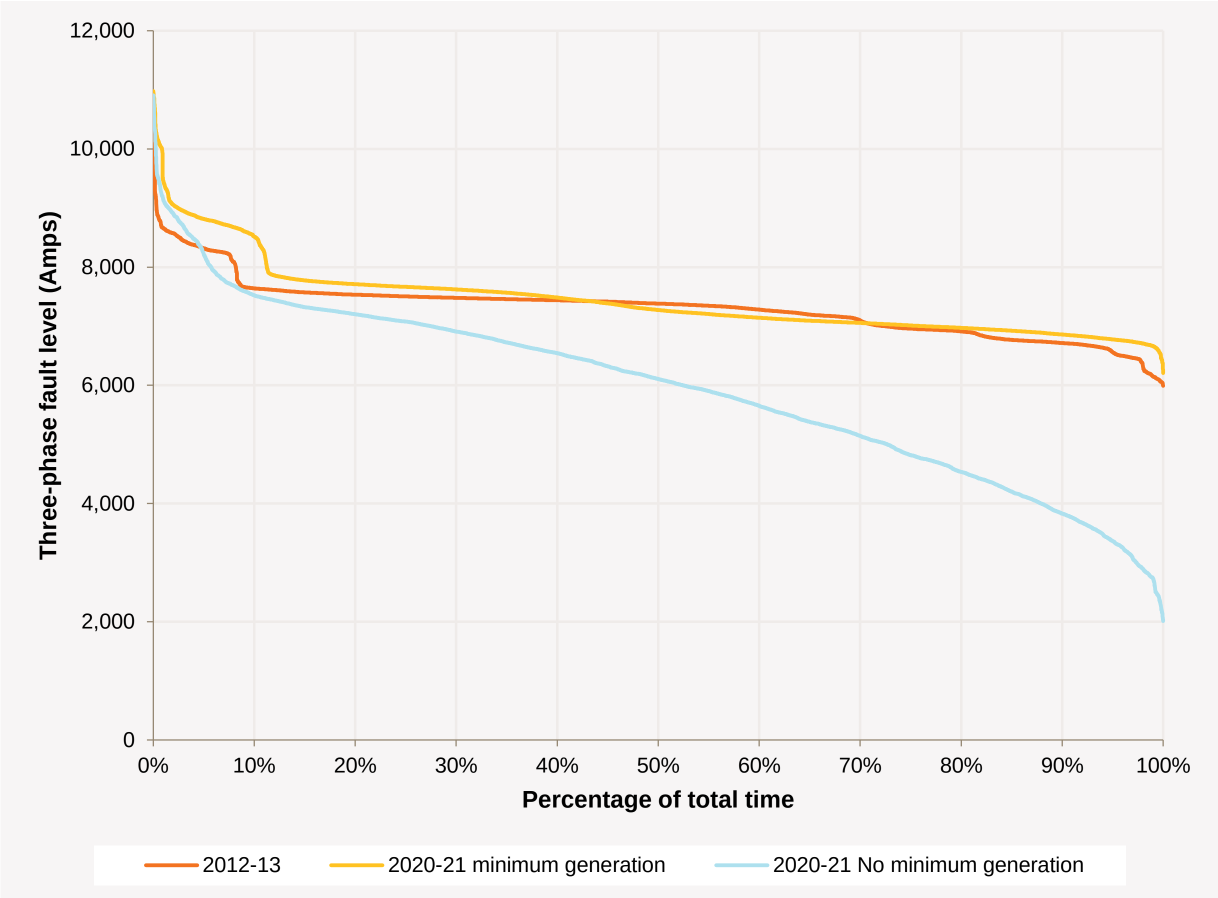
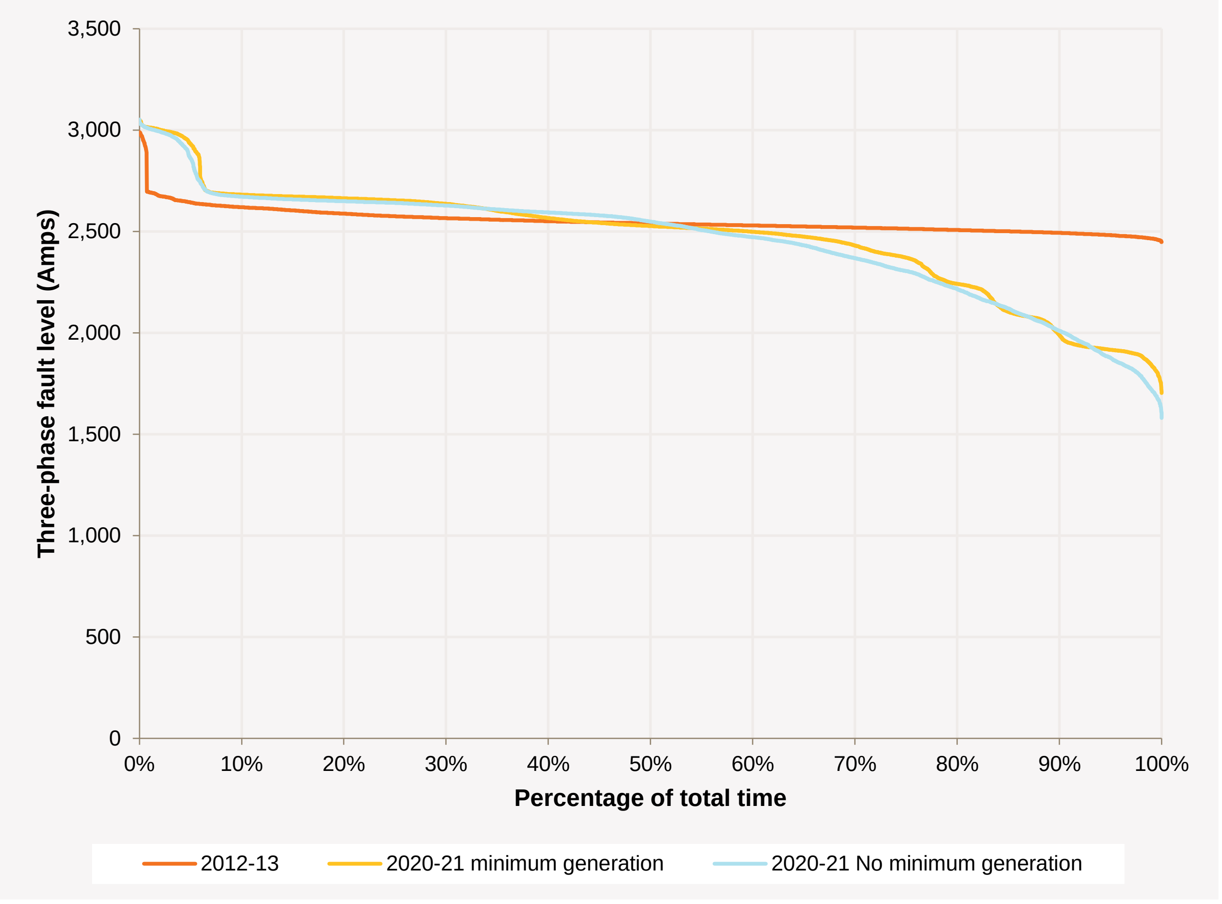


Figure 7-9 — Simulated Derby 110 kV fault levels



The 2012–13 and 2020–21 simulations with minimum generation limits produce fault levels that are well within (and at the higher end of) the ranges indicated by Transend's APR.

The 2020–21 simulations without minimum generation limits produce fault levels lower than those found in the other studies, suggesting that the commitment and de-commitment practices of units is important in determining how Tasmanian fault levels are affected by high volumes of wind generation—at least for busses electrically close to major generation, such as George Town 220 kV.

Transend advised AEMO that a short-circuit ratio of approximately 1,200 MVA is required at the George Town 220 kV bus for stable operation of Basslink at high levels of import into Tasmania, and around 2,500 MVA is required for high levels of export from Tasmania. This corresponds to a fault level of around 3,150 A and 6,500 A respectively.

Figure 7-8 suggests George Town 220 kV fault levels in 2020–21 could fall below the levels required for high Basslink imports into Tasmania around 5% of the time (450 hours a year), and below the level required for high export from Tasmania up to 60% (5,300 hours a year).

This would most likely occur during low demand and high wind periods, when requirement for synchronous generation in Tasmania to meet the demand is lowest. This in turn may result in curtailment of Basslink transfers to ensure stable operation, if no other measures were taken to ensure adequate fault levels at the George Town 220 kV Bus.

The results for the other busses shown suggest that the more geographically remote from synchronous generation the bus is, the less variation in fault level it exhibits. This can be explained by the increased importance of transmission system impedance, rather than generation dispatch, in determining fault levels at more electrically remote busses.

This observation suggests that fault levels at more remote wind generation connection points cannot be readily managed by controlling the dispatch of generation in other parts of the transmission system. If these remote locations require increased fault levels, it must be managed through local arrangements.

7.4.2 South Australia

ElectraNet's 2013 APR[49] provides maximum fault levels for all busses in the South Australian system to the year 2018. Table 7-2 summarises the 2018 fault levels for a geographically diverse selection of busses where AEMO has modelled new wind generation.

Table 7-2 — Fault levels for modelled South Australian busses

Bus	Region	Maximum fault level (kA)
Krongart 275 kV (South East 275 kV as proxy)	South East (CS)	8.4 kA
Port Lincoln 132 kV	Eyre Peninsula (EPS)	2.7 kA
Brinkworth 275 kV	Mid North (MNS)	5.4 kA
Robertstown 275 kV	Mid North (MNS)	9.7 kA
Cultana 275 kV	West Coast (WCS)	6.4 kA
Parafield Garden West 275 kV	Yorke Peninsula (YPS)	16.9 kA

While analysis was conducted for all six busses, only two representative charts are included here for comparison. They show fault levels for a bus electrically close to existing generation, and for a more electrically remote bus.

Figure 7-10 and Figure 7-11 present the calculated fault levels for the Port Lincoln and Robertstown busses respectively. These are based on simulated 2020–21 outcomes under the optimistic and pessimistic scenarios. A 2012–13 scenario is also included for comparison.

[49] ElectraNet, "Transmission Annual Planning Report". Available: http://www.electranet.com.au/network/transmission-planning/transmission-annual-planning-report/. Viewed: 28 July 2013.

Figure 7-10 — Simulated Port Lincoln 132 kV fault level

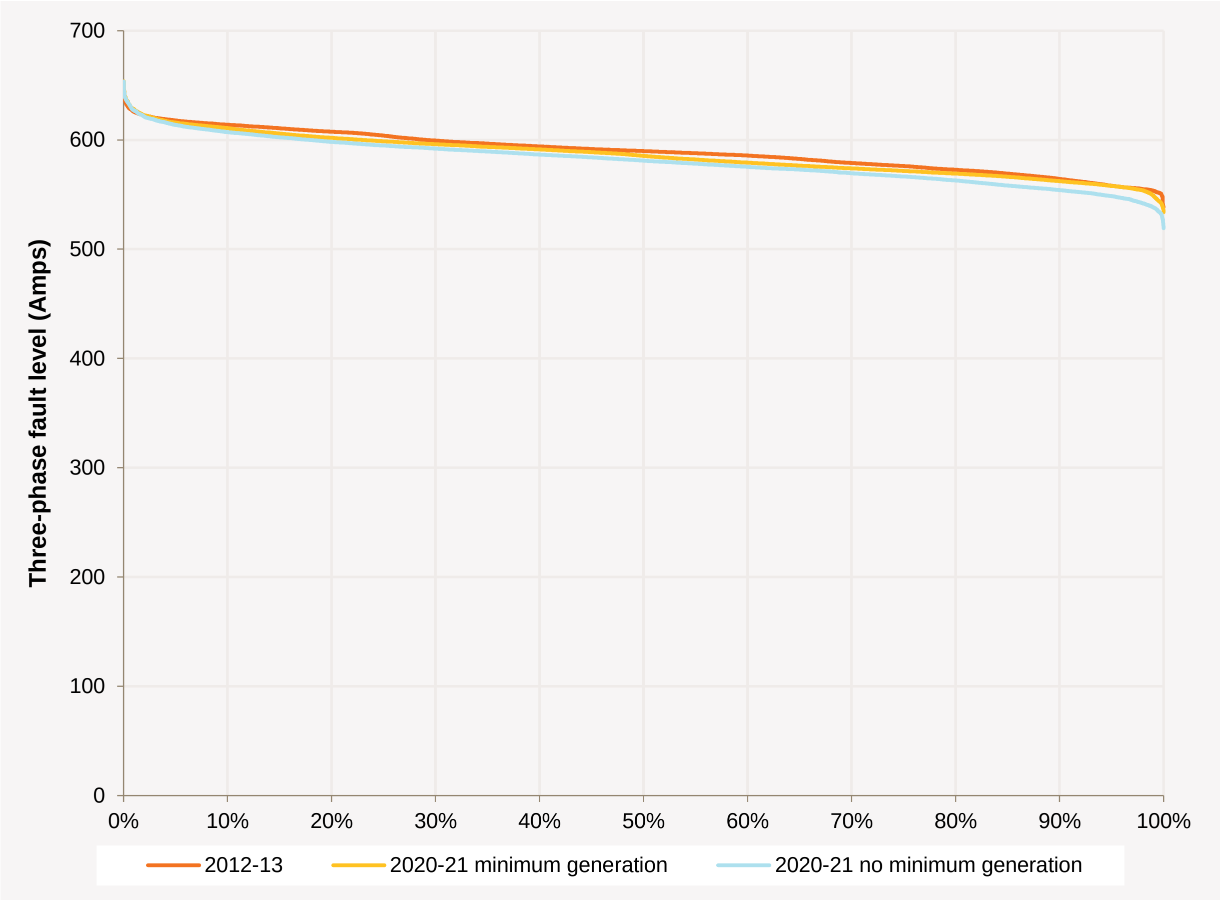
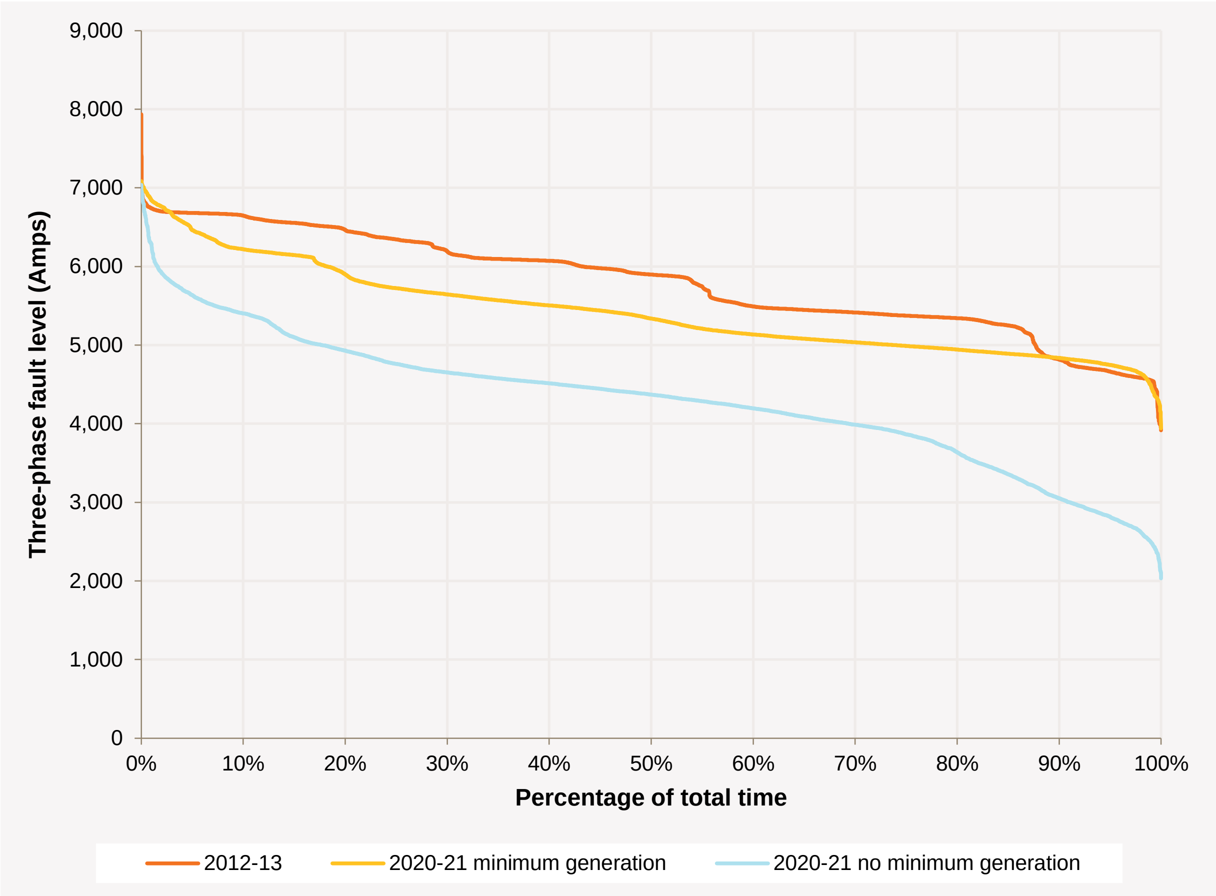


Figure 7-11 — Simulated Robertstown 275 kV fault level



Again, these studies suggest that the largest variations in fault levels will occur at busses that are electrically close to existing generation, in this case the Robertstown 275 kV Bus, where nearby generation may be economically displaced by increasing wind generation. These studies suggest that minimum fault levels, as low as 20% of the maximum possible values, may occur at these electrically strong busses due to high levels of wind integration.

For more electrically remote busses, the effects of increasing wind generation on fault levels are less significant. An example of this is shown in Figure 7-10 for the Port Lincoln 132 kV Bus, which lies at the extreme end of the NEM transmission system. The principal factors determining fault levels at this bus are the operation of local generation at Port Lincoln, and impedance of the 132 kV transmission system supplying Port Lincoln.

These figures again show that dispatch of more remote generation is not significant. As the market simulations used for this work did not dispatch the Port Lincoln generation, fault levels at this 132 kV Bus varied over a relatively small range, even with large changes in wind generation dispatch in other parts of the South Australian power system.

This suggests that if minimum fault levels are required to connect generation at these more remote connection points, then controlling the dispatch of generation in other parts of the transmission system will not be effective in managing fault levels at these points. Other more local arrangements will be required.

7.4.3 Victoria

AEMO's 2013 Victorian Short Circuit Level Review[50] provides the maximum fault levels for all busses in the Victorian system to the year 2017. Table 7-3 summarises the 2017 fault levels for a geographically diverse selection of busses where AEMO modelled new wind generation.

Table 7-3 — Fault levels for modelled Victorian busses

Bus	Region	Maximum fault level (kA)
Ballarat 220 kV	NWV	12.0
Horsham 220 kV	NWV	3.2
Hazelwood B4 220 kV	SEV	35.9
Mortlake 500 kV	CS	9.3
Rowville Bus 1 220 kV	VIC Metro	31.3

While analysis was conducted for all five busses, only two representative charts are included here for comparison. They show fault levels for a bus electrically close to existing generation (Hazelwood Bus B3/4 220 kV in the Latrobe Valley), and also for a more electrically remote bus (Ballarat 220 kV).

Figure 7-12 and Figure 7-13 present the calculated fault levels for the Ballarat and Hazelwood busses respectively. These are based on simulated 2020–21 outcomes under the optimistic and pessimistic scenarios. A 2012–13 scenario is also included for comparison.

[50] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Victorian-Annual-Planning-Report-2013/Victorian-Short-Circuit-Level-Review.

Figure 7-12 — Simulated Ballarat 220 kV fault levels

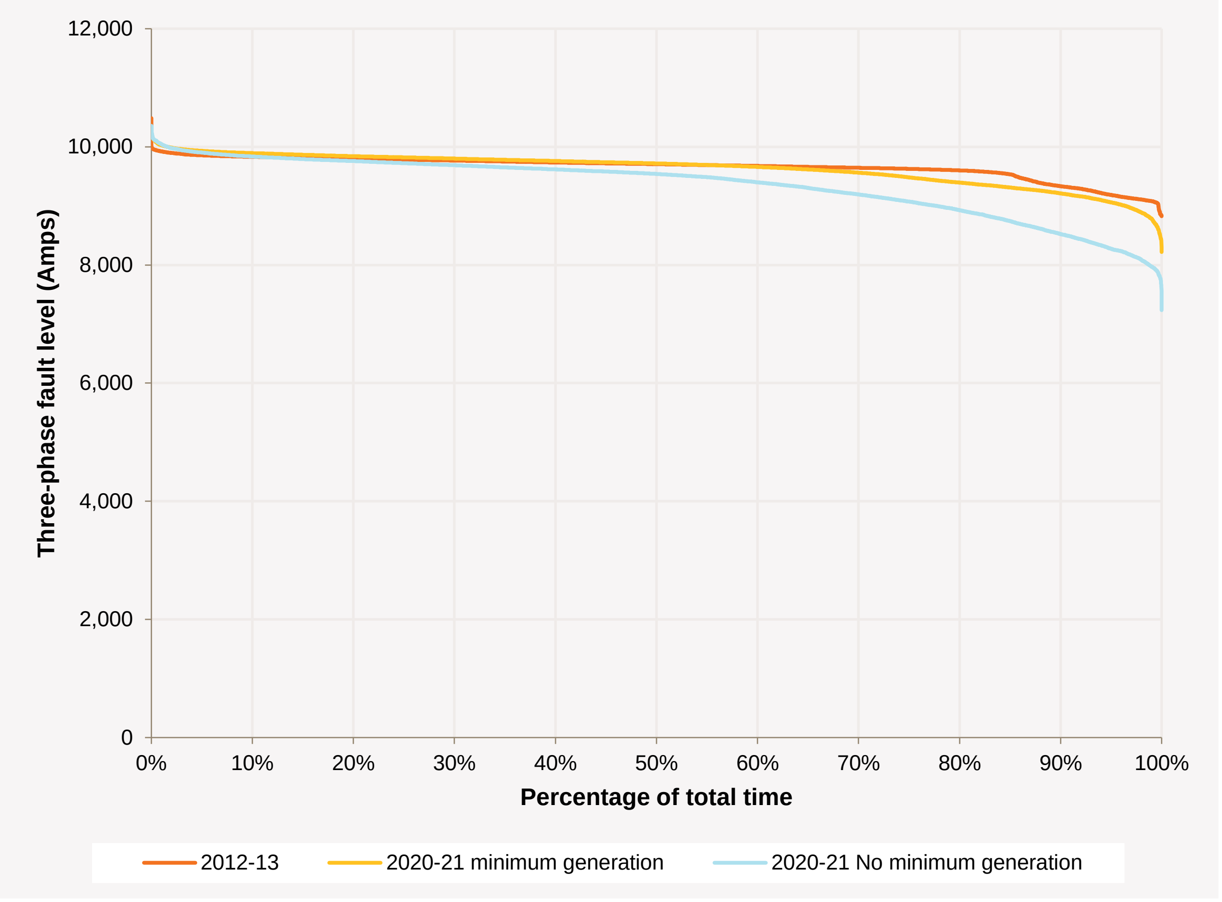
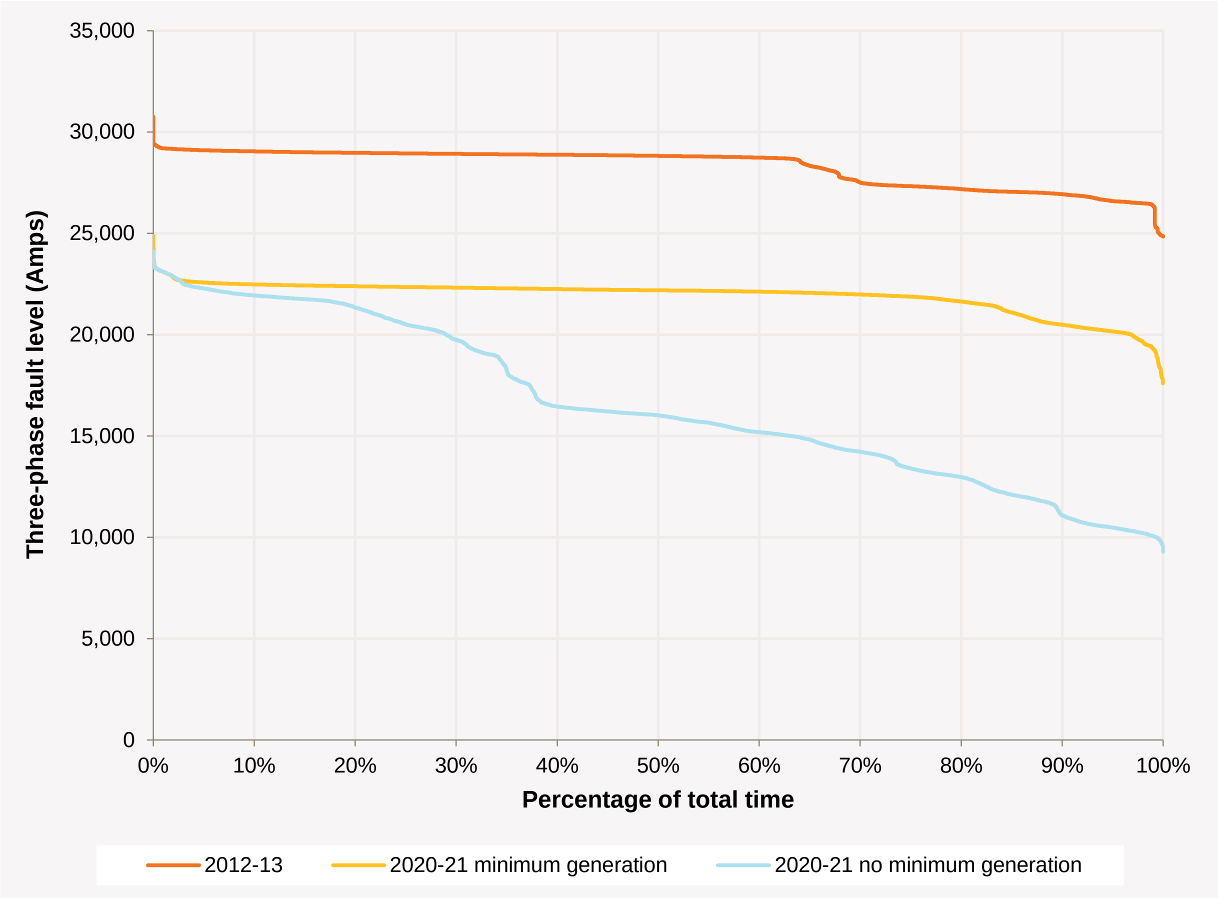


Figure 7-13 — Simulated Hazelwood 220 kV Bus 3/4 fault levels



These studies again suggest that the largest variations in fault levels will occur for electrical connection points close to large amounts of synchronous generation. Fault levels calculated for electrically strong busses, such as Hazelwood in the Victorian Latrobe valley, are sensitive to generation levels.

The reduction seen in Figure 7-13 at this bus in 2020–21 compared to 2012–13 is due to the modelled retirement of generating units in the Latrobe Valley by 2020–21.

More electrically remote Victorian busses, such as Ballarat, do not appear to experience large changes in fault levels when existing generation is displaced. The fault levels at these busses are determined by the high electrical impedance of the 220 kV transmission networks supplying them, rather than the dispatch of remote conventional synchronous generation.

7.5 Network limitations and utilisation

Market modelling was used to quantify congestion based on thermal and network stability limits, and this section presents findings from this work. It also includes information on interconnector utilisation and limits.

In 2011, AEMO also undertook a study on the variability of wind and its correlation with regional demand. That report, available from AEMO's website[51], provides a range of statistical observations on the variable nature of wind generation, and supplements some of the work done in this report.

7.5.1 General observations

Figure 7-14 compares the simulated NEM energy generation mix for both 2012–13 and 2020–21, and shows a strong shift towards renewables. The 2020–21 simulation n this figure has thermal generation modelled as being able to run flexibly over the entire operating range.

Figure 7-14 — Simulated changes to generation mix[52]

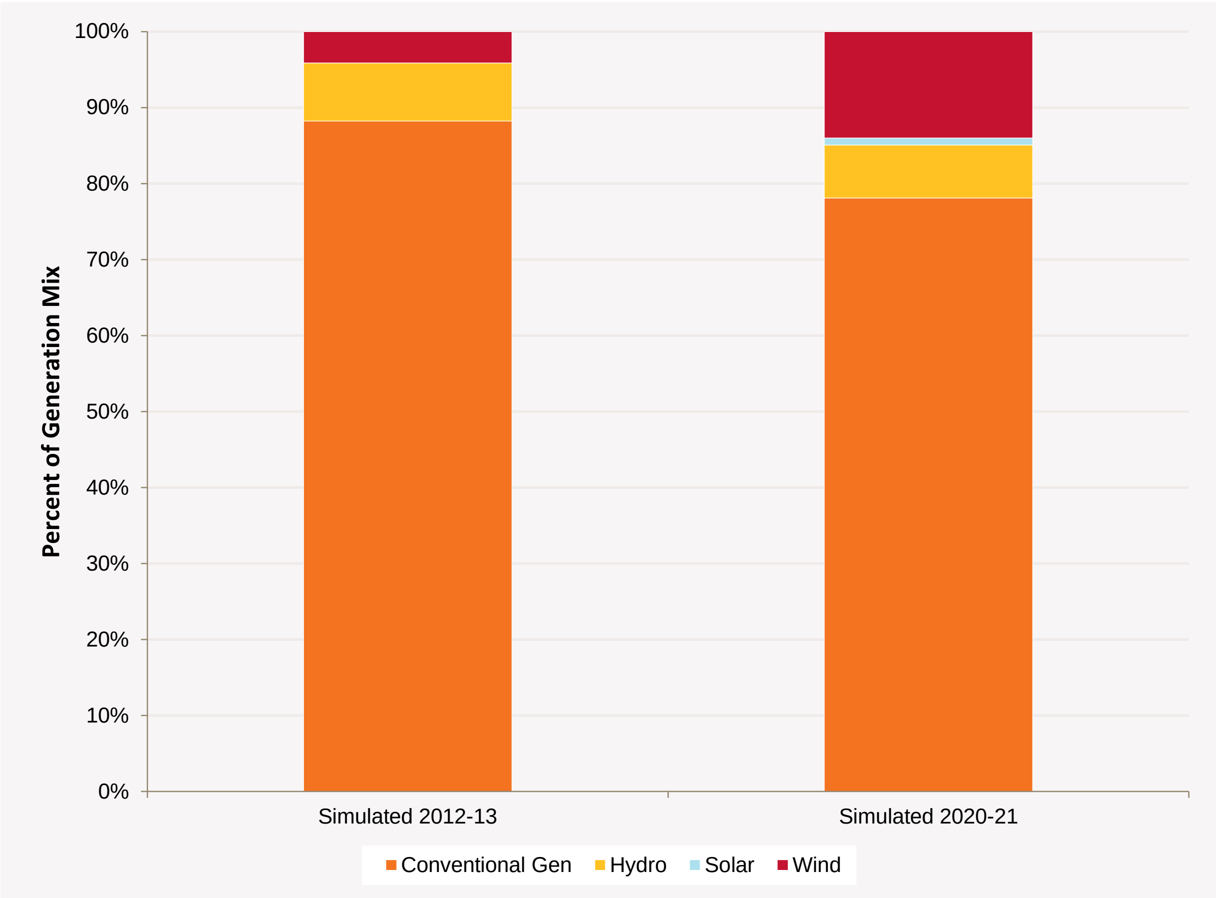


Table 7-4 shows the change in energy by region and generation type. It highlights a shift in thermal generation from Victoria to the northern states, as thermal generation in Victoria is modelled to retire, and demand is assumed to increase in Queensland.

[51] AEMO. 'Work Package 3: Simulation using Historical Wind Data'. Available: http://www.aemo.com.au/Electricity/Planning/Related-Information/~/media/Files/Other/planning/0400-0056%20pdf.ashx.

[52] The solar generation included in the figure is utility-scale solar (either PV or concentrated solar thermal). Rooftop PV is accounted for in the energy forecasts as a reduction in the load on the transmission system.

Table 7-4 — Modelled change in energy by generation type 2012–13 to 2020–21 (GWh)

	Thermal	Hydro	Utility solar	Wind generation
Queensland	10,402	11	458	800
New South Wales	9,960	353	0	6,690
Victoria	-19,305	202	845	7,728
South Australia	390	0	863	4,133
Tasmania	-187	-44	0	4,325
NEM-wide	1,260	522	2,166	23,676

Total renewable energy output in the 2012–13 simulation was 23.6 TWh (mostly comprising hydro and wind generation).

The additional 26.4 TWh of renewable energy identified in Table 7-4 yields a total of 50 TWh of NEM renewable generation by 2020–21. Excluding hydro baseline levels of approximately 14.5 TWh, approximately 35.5 TWh of this NEM renewable generation was produced to meet the national LRET target of 41 TWh.

Table 7-5 reports regional simulated wind capacity factors in 2020–21, based on simulated wind traces with no network or supply limitations considered, i.e., a fully unconstrained case, representing the maximum possible output of wind generation. Simulated capacity factors for individual wind bubbles are presented in Section 8.2.3

Table 7-5 also reports (in brackets) an indication of how these values change when subjected to network congestion and oversupply constraints (where wind output is higher than local demand and regional export capability).

Table 7-5 — Regional capacity factors under ideal and constrained system conditions 2020–21

	Capacity factor ideal (constrained) %	Maximum proportion of local demand Ideal (constrained) %
Queensland	34.4 (34.4)	5 (5)
New South Wales	36.5 (36.5)	37 (37)
Victoria	37.6 (24.4)	106 (91)
South Australia	38.5 (32.9)	243 (166)
Tasmania	40.5 (40.5)	142 (130)
NEM-wide	37.8 (30.9)	57 (38)

Key observations about this table are:

- Under ideal conditions, both Tasmania and South Australia have the highest average wind capacity factors.
- Victoria shows the largest reduction in average capacity factor once network and oversupply constraints are considered. Section 7.5.2 explores the reasons for this in more detail.
- Wind output in South Australia, Tasmania, and Victoria could potentially meet local demand entirely during some parts of the year. South Australia shows available wind in some periods as high as 243% of South Australian demand.
- Applying network and oversupply constraints can result in curtailment of wind generation output during low demand periods, though South Australia and Tasmania are still able to meet local demand and offer exports entirely using wind in some hours.

7.5.2 Wind congestion and interconnector capability

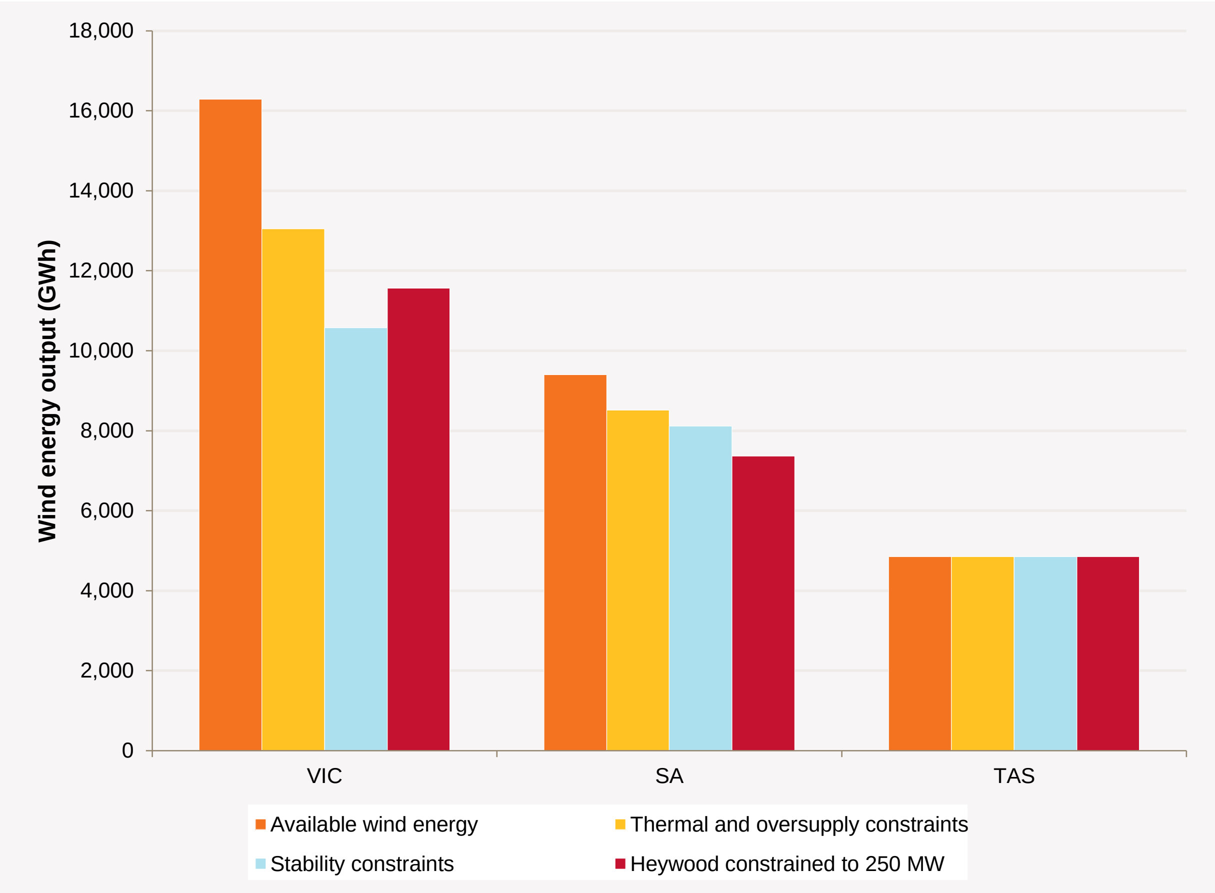
A review of simulated wind dispatch compared to full potential generation capacity (based on wind traces) for each region shows that wind was modelled as able to produce to, or very close to, its full capacity in Tasmania, New South Wales, and Queensland during 2020–21. However, a significant reduction in wind generation output was observed in Victoria and South Australia.

All scenarios compared in this section allowed operation of thermal generation flexibly over the entire operating range. These scenarios result in the higher wind generation output compared to scenarios where minimum generation limits of conventional synchronous generation are rigidly enforced at all times.

Figure 7-15 quantifies this result, comparing:

- Maximum available wind energy in the regional wind traces, given the assumed installed wind generation capacity and assumed capacity factor.
- The wind dispatched when constrained only by thermal network limitations and oversupply (where wind output is greater than demand and available export capability), but not by updated interconnector limits.
- The wind dispatched when new wind generation was also explicitly considered in updated interconnector transient and voltage stability limit equations.
- The wind dispatched when Heywood Interconnector transfers are limited to 250 MW in both directions, to simulate conditions where separation of South Australia from the rest of the NEM is considered credible.

Figure 7-15 — Wind energy output compared with wind availability

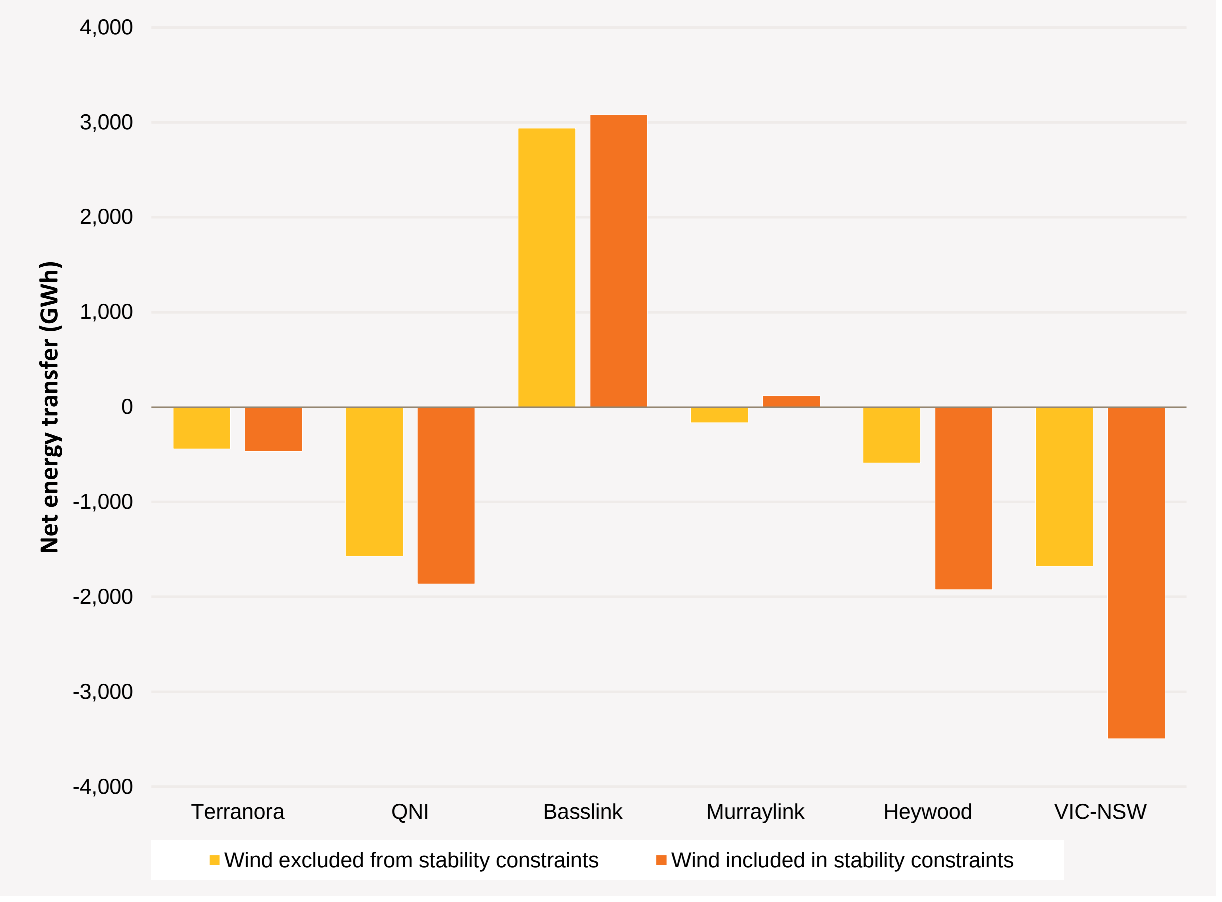


Key observations from this chart are:

- Maximum simulated curtailment of wind output was around 5,750 GWh in Victoria and 1,260 GWh in South Australia, compared to the energy output achievable with no constraints imposed. This represents around 35% and 15% respectively of the the maximum potential wind generation energy in these regions.
- This reduction in wind generation output was due to a combination of thermal constraints, oversupply (where available wind is greater than local demand and available export capability), and consideration of new wind generation in updated stability constraints.
- Reduction of wind generation due to stability constraints occurred predominantly in the south-western area of Victoria, and the south-eastern coast of South Australia.
- Reducing Heywood transfer capability to 250 MW allows higher wind generation output in Victoria, as this acts to relax Victorian stability constraints. This limit on Heywood transfers prevents some wind exports from South Australia, resulting in a net decrease in wind energy output in that region.

The market modelling further explored the impact of stability constraints on interconnector transfers and Victorian wind generation. Figure 7-16 compares simulated interconnector energy transfers for each region, both with and without stability limits applied.

Figure 7-16 — Comparison of simulated net interconnector energy transfers for 2020–21



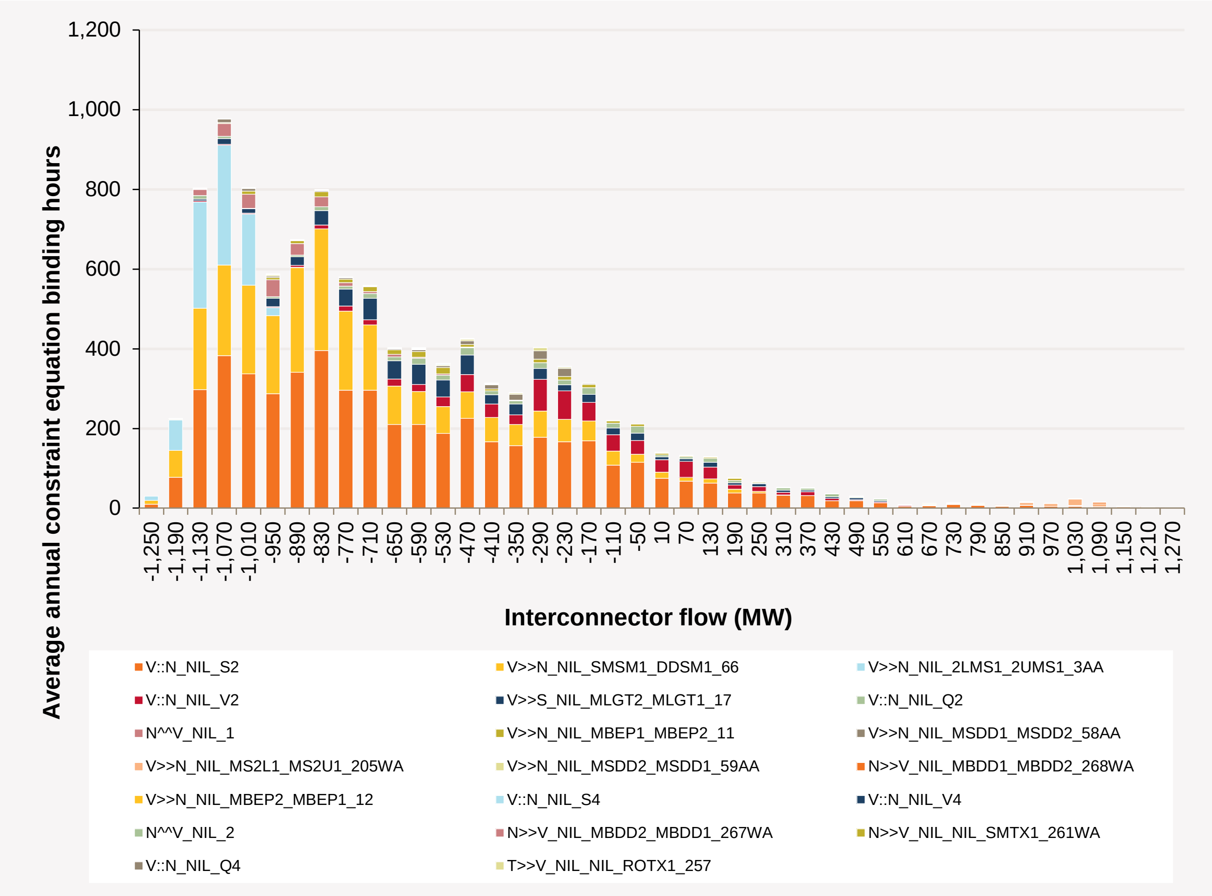
Key observations from this chart are:

- Only minor changes are evident in transfers on the Terranora and QNI interconnectors (between Queensland and New South Wales), and the Basslink Interconnector (between Tasmania and Victoria).
- Substantial increases in Victorian imports occur on the other interconnectors from South Australia and New South Wales when stability constraints are applied. As noted previously, stability constraints limit wind generation on the south-western area of Victoria, leading to the increased need for, and access to, net imports observed here.

- The most important stability constraint affecting interconnector flows was the transient stability constraint equation V::N_NIL_S2, which limits Victorian interconnector export flows and generation to prevent transient instability for the fault and trip of a Hazelwood – South Morang 500 kV line in Victoria.

Figure 7-17 presents the modelled distribution of binding constraints on the Victoria – New South Wales Interconnector; and shows how often particular constraint equations were limiting flow and at what flow level they were limiting. Negative interconnector flows represent power transfer into Victoria.

Figure 7-17 — Constraint distribution: VIC–NSW Interconnector, 2020–21



This chart shows that the constraint equation V::N_NIL_S2 limited interconnection flows and wind farm output for a combined total of 5,062 hours in 2020–21. This is almost double the duration seen when new wind generation was excluded from these stability constraints.

The studies presented in this chapter assume that wind is dispatched in preference to all existing synchronous generation; however, if thermal units are dispatched to their minimum stable levels ahead of wind, considerably more thermal generation is dispatched in Victoria resulting in a net export to New South Wales.

This changes the general shape of the above chart, but still identifies the constraint equation V::N_NIL_S2 as the most significant, binding for approximately 3,176 hours in 2020–21.

These findings may indicate:

- Locational signals for new wind farm investors, which may act to counter investment incentives driven purely by wind resource quality on the south-west coast of Victoria and south-east coast of South Australia.
- A need to address the identified network limitations, including transient stability constraints, potentially capturing market benefits by allowing greater output from low-cost wind generation in these areas.

CHAPTER 8 - SUPPLEMENTARY INFORMATION

8.1 Interconnector limits assessment methodology

This section describes the methods AEMO used to assess the impact of increased wind generation on National Electricity Market (NEM) interconnector capability. These are summarised as follows:

- Establish a power system study case operating at or near the existing interconnector power transfer limit of interest, with all new wind generation operating at 0 MW output.
- Increase the output of wind generation within a single wind bubble by an incremental amount, normally 10% of the installed wind capacity in that bubble.
- Reduce the corresponding amount of other generation within the same region to ensure no change in the interconnector flow. Determine the generation reduced by the economic merit order of generation for that region. This reflects the reality that wind generation is likely to economically displace other generation within a region when it is operating.
- Assess the interconnector limit for this new case to determine whether it increased or decreased relative to the initial starting case, and how much it had changed.
- Increase the wind generation in the wind bubble of interest again, normally by another 10%. Reduce other generation within the same region to ensure no change in the interconnector flow. Determine the change in the interconnector limit. Repeat this process until the wind generation is at 100% output.
- This produces a series of data points for change in interconnector limit versus wind generation output, which can then be analysed to determine a sensitivity factor. This analysis is shown below in Figure 8-3.
- This analysis was undertaken one wind bubble at a time, on the assumption that the effect of each wind bubble on the interconnector limit was independent of the others, and varied linearly with the wind farm megawatt output.
- This analysis provides a linear approximation coefficient relating the change in each interconnector limit to the output of wind generation in each wind bubble.

This method of determining the effect of wind generation on interconnector limits is not as rigorous as the process used by TNSPs to determine the existing operational NEM interconnector transfer limits. However, given that these studies deal with a model of the power system seven years into the future, assume a particular performance level from future wind generation, and make significant assumptions about the size and connection points of future wind generation, this technique is consistent with the overall accuracy of the studies.

Specific methods and criteria used to determine the impact of wind generation on transient stability limits and on voltage stability limits are described in sections 8.1.1 and 8.1.2 respectively.

8.1.1 Transient stability

Assessment criteria

AEMO performed transient stability studies to assess whether a system operating point is transiently stable using the following stability criteria:

- Following the most critical disturbance, the maximum rotor angle spread between any two interconnected machines must not be greater than 360 degrees.
- The maximum angle swing of any individual machine must not be greater than 160 degrees.
- The halving time of any inter-regional or intra-regional oscillation must be less than five seconds.

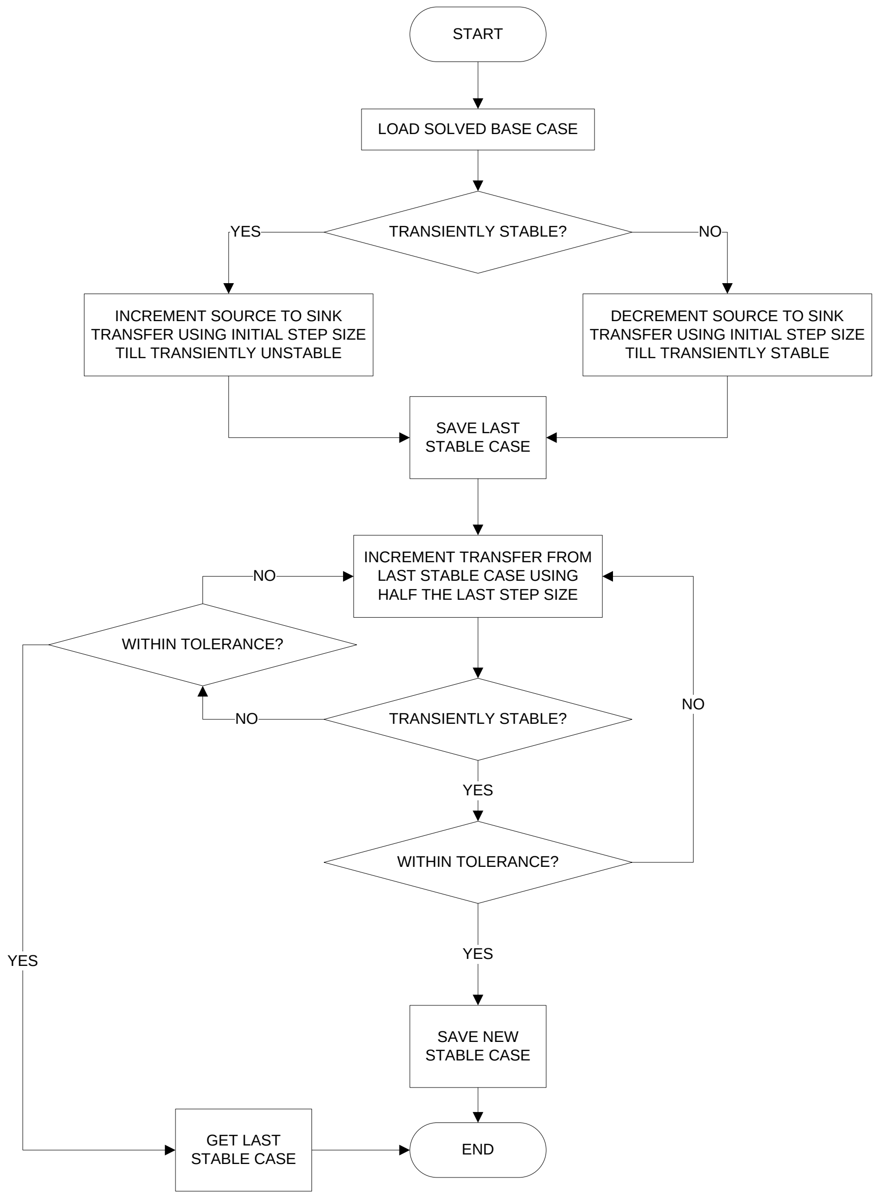
Methodology

AEMO's objective was to determine the maximum power transfer as set by transient stability on a given interconnector for a given transient disturbance. A binary search algorithm using custom software script running within PSS/E was used to determine interconnector transient stability transfer limits. This algorithm starts with a base case interconnector power transfer level, and performs time domain simulations of specified contingency events.

For each simulation run, the power transfer between the source and sink area is increased or decreased in steps using predefined groups of generators and loads before assessing transient stability. This process is iterated until the transient stability transfer limit is determined to within a predefined tolerance.

A flowchart illustrating the operation of this binary search process is shown in Figure 8-1.

Figure 8-1 — Flowchart of process for determining transient stability transfer limits



8.1.2 Voltage stability analysis

Assessment criteria

AEMO performed voltage stability studies by considering the relationship between reactive power (Q) and voltage (V) (Q/V analysis). This analysis determines the reactive margin at critical power system busses, providing an indicator of the voltage stability of the power system. In these studies, the reactive margin at critical busses must be at least 1% of the maximum fault level, and power system voltage at critical busses must not fall below 90% of the nominal voltage following a contingency.

Methodology

The voltage stability limit studies produce a family of curves showing related interconnector flow, reactive margin, and wind generation output (see Figure 8-2). The dashed line in this figure represents the limiting reactive margin of 1% of the bus fault level.

By analysing the data for wind generation versus the change in limit from a case with no wind generation, AEMO determined the impact of wind generation on the limit, see Figure 8-3 below.

Figure 8-2 — Q/V curve for a given power system bus

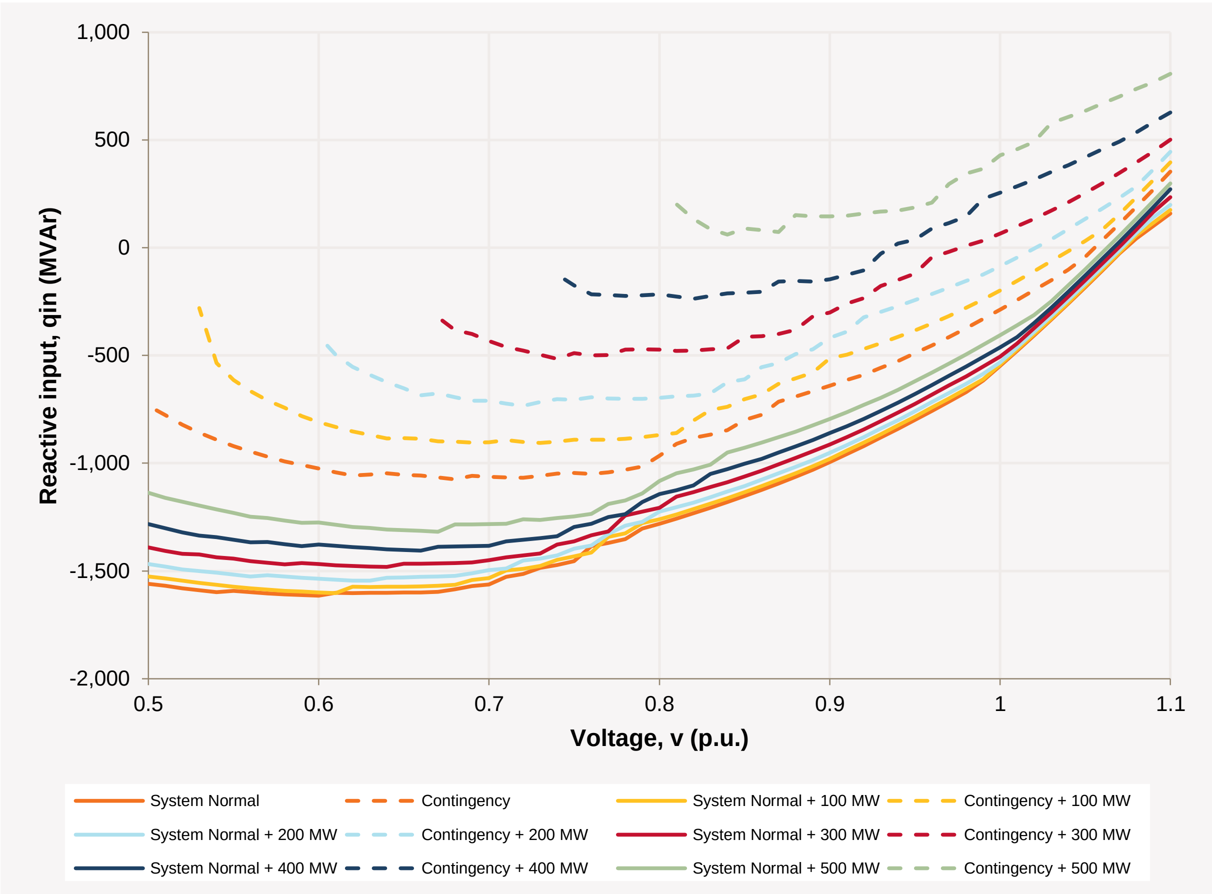
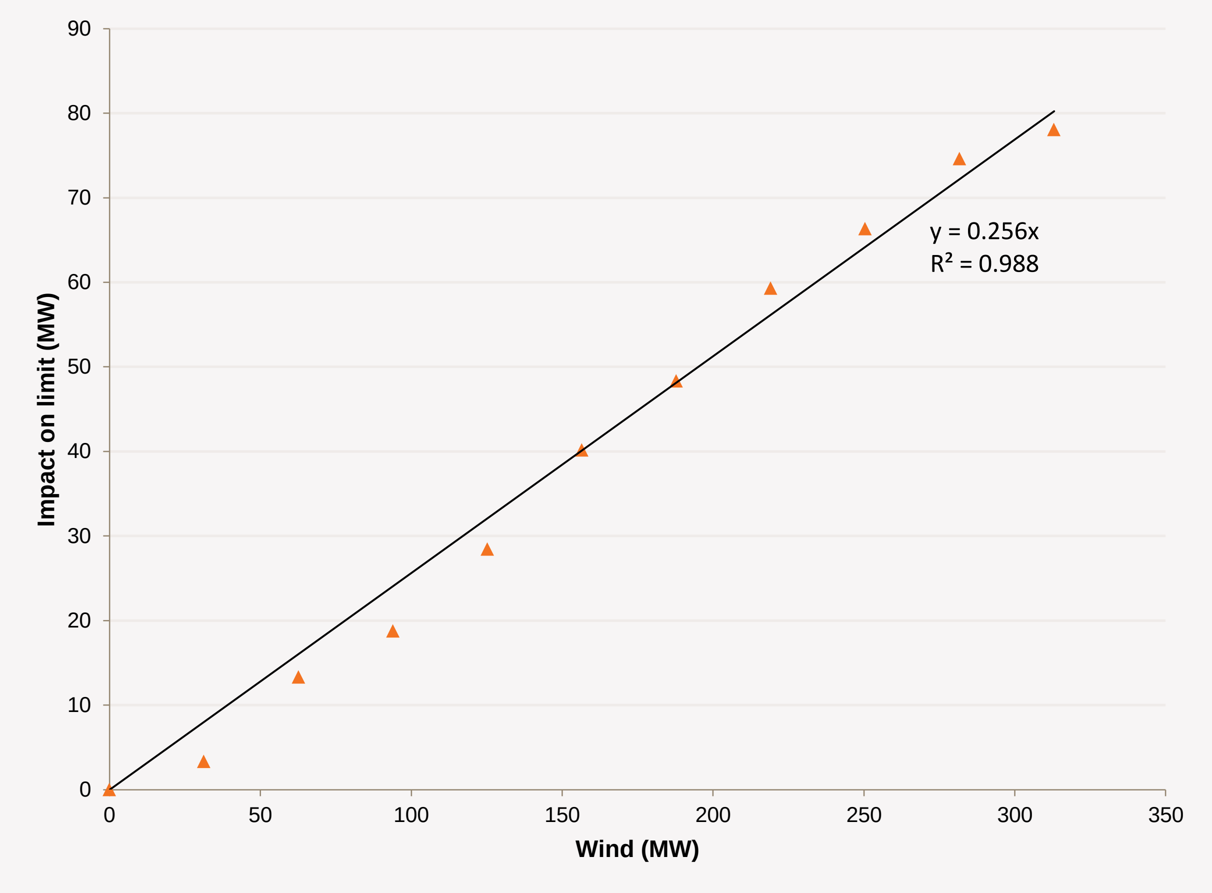


Figure 8-3 — Change in limit versus wind generation



8.1.3 Oscillatory stability

Assessment criteria

To assess if a system operating point is sufficiently stable with respect to oscillatory stability, AEMO used the following stability criterion during the assessment:

- The halving time of any inter- or intra-regional oscillation must be less than five seconds.

Methodology

For this report, AEMO investigated the existence of unstable oscillatory response modes by time domain simulation of a large power system disturbance. The simulated oscillatory response as the system returns to a stable operating point is then examined.[53]

AEMO assessed the oscillatory stability of the NEM for the proposed level of wind integration in 2020 and high levels of interconnector transfer.

These studies confirmed that the halving time of known critical power system oscillation modes remained below five seconds.

[53] Operationally, AEMO determines oscillatory stability transfer limits using eigenvalue analysis of the linearised power system equations.

8.1.4 Calculating offsets to existing limit equations

For the studies used in this report, AEMO calculated changes in interconnector limits for changes in wind generation output. AEMO performed linear regression on this data to determine the strength of the relationship between the two. For each wind bubble that exhibits a relatively linear relationship between wind farm capacity and interconnector limit, AEMO calculated a sensitivity factor. This sensitivity factor can be translated into a megawatt offset applicable to the original interconnector limit equation.

For the purposes of this study the effect of each bubble's wind generation on each interconnector limit considered was linear, and independent of the effects of other wind bubbles.

8.2 Market simulation methodology and assumptions

This section explains the methodology and assumptions used in Chapter 7 - (market simulation studies); undertaken to quantify the potential operational impacts identified in chapters 3, 4, and 5.

The modelling assumptions are generally consistent with those used in the power system studies. This section presents only those assumptions that diverge or qualify those presented in Chapter 2.

8.2.1 Methodology

The market simulations model hourly National Electricity Market (NEM) market dispatch for 2020–21, with some additional simulations undertaken for 2012–13 for comparison. AEMO conducted these simulations using the PROPHET Software package, produced by Intelligent Energy Systems (IES).[54]

The key objective of the analysis was to explore hourly generation dispatch and flows. AEMO conducted simulations based on a single iteration, without consideration of generator forced outages.[55] To ensure consistency with the technical studies, these simulation runs used the 10% probability of exceedance (POE) demand forecast from the 2012 National Transmission Network development Plan (NTNDP) planning scenario.

Other assumptions include:

- All technical parameter and cost assumptions are as per the 2012 NTNDP planning scenario.
- Generation dispatch is based on short-run marginal cost (SRMC) bidding of both existing and new generators. Wind generation is bid with a non-zero SRMC.
- Wind generation outputs are based on wind traces developed from historical wind data, consistent with AEMO's wind bubble methodology from the 2012 NTNDP. New wind generation is modelled as semi-scheduled generation that can be constrained down by the dispatch engine if necessary.

Further assumptions are detailed in the following sections.

8.2.2 Assumptions

Demand

The hourly demand traces for the market simulations were those used for the 2012 NTNDP planning scenario. The demand traces were developed using a historical 2009–10 reference demand trace, scaled up to match energy demand as per the 2012 NEFR.[56]

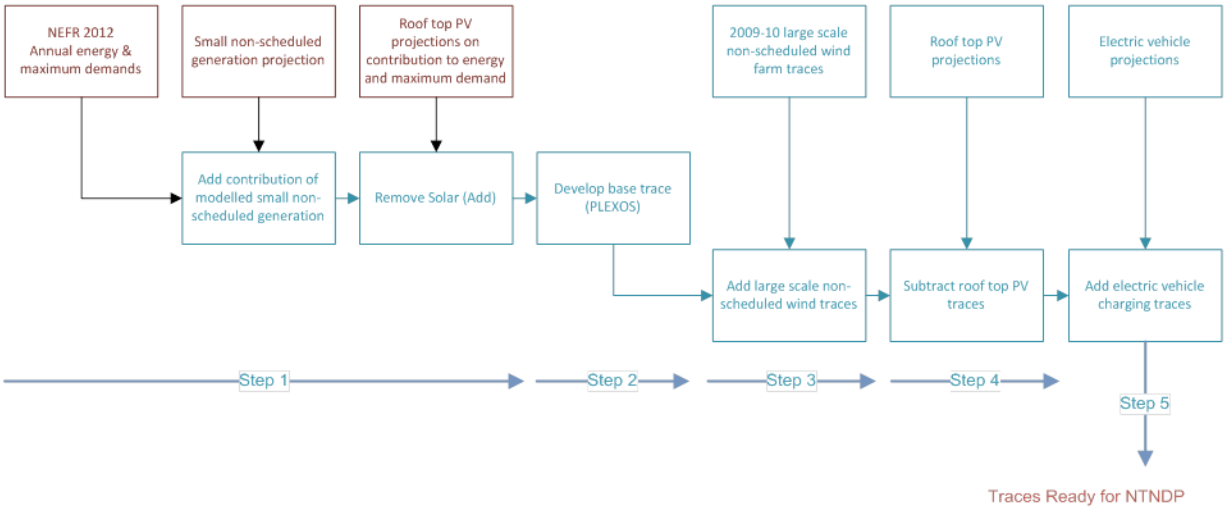
Further modifications to these traces were required to ensure that embedded generation (in particular rooftop PV and forecast electric vehicle charging) follow realistic daily patterns. The change process is described by the process map in Figure 8-4.

[54] http://www.iesys.com/ies/ProductsandServices/Prophetsuite.aspx.

[55] The modelling neither assumed random outages nor accounted for any reduction in annual energy produced through derating of generation during periods of high ambient temperature.

[56] AEMO. Available: http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012.

Figure 8-4 — Load growth adjustment process



AEMO also undertook a sensitivity study for the closure of a large Tasmanian industrial load. This was modelled by reducing the Tasmanian load profile by 100 MW in all periods of that study.

Generation

Generation capacity, including new wind generation, is based on the long-term simulation results of AEMO's 2012 NTNDP planning scenario. Generator forced outage rates are not considered.

Generator bids use SRMC bidding. Minimum generation levels are bid in at $0 in base case studies, and all capacity is bid at SRMC in sensitivity studies.

Generator marginal losses are consistent with 2012–13 generator marginal loss factors (MLF).[57]

Wind generation

A wind farm's available output is determined by a wind trace, which is defined in terms of the hourly maximum generation capacity. An existing semi-scheduled wind farm's generation capacity is based on historical information for 2009–10 as extracted from AEMO's Market Management System (MMS).

A new wind farm's calculated available generation capacity is based on the wind bubble concept. A wind bubble is a geographical area where wind speeds are considered sufficient for new wind development. Modelled wind bubbles are shown in Figure 2-1.

AEMO developed a representative hourly wind speed profile is developed for each wind bubble, based on historical hourly wind speed data for 2009–10. The wind speed profiles for all the wind bubbles are converted to normalised wind turbine power output profiles based on a generic turbine power conversion curve. New wind generation capacity generates according to a combination of the normalised power output profile and its modelled capacity.

PV generation

Hourly generation from distribution-connected rooftop PV is reflected in the demand profile (as per Figure 8-4). Generation from larger, transmission-connected utility-scale PV plants is based on hourly profiles from typical daily insolation each month.

[57] AEMO. Available: http://aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/~/media/Files/Other/loss%20factors/MLF_2012_13_Main_Report_16_MLf.ashx.

Modelling minimum generation levels

AEMO found the treatment of minimum generation levels in the market simulations to be critical to the results.

Market simulations are based on generators offering capacity at SRMC. For thermal generators, capacity below their minimum stable operating levels is offered at zero price.[58] Wind generation is offered with a very low, but non-zero SRMC. This means that the minimum operating levels of synchronous generation is offered more cheaply than wind generation, so generation at these levels will be dispatched ahead of wind generation.

Due to the large volumes of simulated energy provided by wind generation in 2020–21, these default modelling assumptions result in many hours of the simulated year where major generating units are forced to operate at minimum load. For example, in some simulations large thermal units in Victoria were operating for over 80% of the year at their minimum load levels; this results in low modelled capacity factors for these units compared to those observed historically. The longer-term financial viability of this operating pattern is doubtful.

To understand the potential implications of this issue, AEMO undertook sensitivity studies allowing generating units to run flexibly across their operating range with all capacity bid in at SRMC. This allowed maximum output from wind farms, although it is not likely to be technically viable for the thermal generating units.

Realistic operational outcomes are likely to fall somewhere between these two scenarios. Some synchronous generating units will withdraw capacity, some will change their plant to allow more flexible operation, and others will continue to operate at their minimum stable operating levels. The range of outcomes modelled allows for bounds to be defined for the study outcomes.

Transmission network

AEMO modelled the transmission network using:

- Thermal constraint equations, which were updated to include all new generation capacity.
- Non-thermal constraint equations, which are based on the constraint equations used in the 2012 NTNDP as a starting point, including oscillatory, transient, and voltage stability constraint equations. As described in Section 2.5.1, AEMO made some modifications to the baseline level of constraint equations after discussion with relevant TNSPs.

Two versions of these constraints were used:

- Non-thermal constraints updated to include new wind generation – used in the business-as-usual case for 2020–21.
- Non-thermal constraints without terms for the new wind generation (but still reflecting the impact of existing wind). This case was used as a sensitivity to observe the specific impact of wind on stability constraints and subsequent interconnector transfers.

Interconnector losses were modelled using loss factor equations as given for 2012–13.[59]

The 2012 NTNDP constraint set was used as the basis for the market simulations, and is available from AEMO's website.[60] The base constraints from this data set were modified based on the power system studies described in Chapter 5 - of this report.

The studies also modelled a sensitivity case with Heywood transfer capability permanently limited to +/- 250 MW. This was to reflect a situation where South Australia was at credible risk of islanding, in which case a 250 MW transfer limit is currently applied to the Heywood Interconnector.

[58] Similar limits apply for hydro units which can have minimum flow requirements, e.g., to comply with environmental requirements.

[59] AEMO. List of Regional Boundaries and Marginal Loss Factors for The 2012–13 Financial Year. Available: http://aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/~/media/Files/Other/loss%20factors/MLF_2012_13_Main_Report_16_MLf.ashx.

[60] AEMO. 2012 NTNDP Assumptions and Inputs. Available: http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan/Assumptions-and-Inputs.

8.2.3 Wind farm capacity factor data for market simulations

New South Wales

Plant	Generation capacity factor trace
Capital Wind Farm	0.3985
Cullerin Range	0.3997
FWN Broken Hill_WIND	0.3653
FWN Buronga_WIND	0.3653
Gunning	0.3751
HUN Bayswater_WIND	0.3155
MRN Bannaby_WIND	0.3750
MRN Yass_WIND	0.3750
MUN Deniliquin_WIND	0.3518
MUN Jindera_WIND	0.3518
NEN Armidale_WIND	0.3553
SEN Cooma_WIND	0.3286
WEN Wallerawang_WIND	0.3553
Woodlawn	0.3985

Queensland

Plant	Generation capacity factor trace
SWQ Blackstone_WIND	0.3435
SWQ Greenbank_WIND	0.3435

South Australia

Plant	Generation capacity factor trace
Canunda	0.3742
CathRocks	0.4081
Clements Gap	0.3855
CS Krongart275_WIND	0.3826
EPS Port Lincoln132_WIND	0.3973
FLS VH66_WIND	0.3813
Hallett 5 The Bluff	0.3835
Hallett Hill Wind Farm	0.3975
Hallett Wind Farm	0.3975
LKBONNY1	0.3452
LKBONNY2	0.3364

Plant	Generation capacity factor trace
LKBONNY3	0.3408
MNS Belalie275_WIND	0.3973
MNS Blyth275_WIND	0.3973
MNS Brinkworth275_WIND	0.3973
MNS Bungama275_WIND	0.3973
MNS Canowie275_WIND	0.3973
MNS Glenriver275_WIND	0.3973
MNS Mokota275_WIND	0.3973
MNS Robertstown132kV_WIND	0.3973
MNS Robertstown275_WIND	0.3973
Mt Millar Wind Farm	0.3934
North Brown Hill	0.4115
Snowtown Wind Farm	0.4036
Starfish Hill	0.3786
Waterloo	0.3950
WattlePoint	0.3220
WCS Cultana275_WIND	0.3937
WCS Lincoln Gap275_WIND	0.3937
YPS PGW275_WIND	0.3973

Victoria

Plant	Generation capacity factor trace
Challicum Hills	0.3408
CS Mortlake_WIND	0.3826
CS Shaw River_WIND	0.3826
CS Tarrone_WIND	0.3826
FWN Red Cliffs_WIND	0.3653
Macarthur	0.3662
NWV Ballarat_WIND	0.3653
NWV Bendigo_WIND	0.3653
NWV Horsham_WIND	0.3653
Oaklands Hill	0.3814
Yambuk	0.3974
Portland 2	0.3974
Portland 3	0.3974

Plant	Generation capacity factor trace
SEV Hazelwood_WIND	0.3667
SWV Terang_WIND	0.3662
Waubra	0.3848

Tasmania

Plant	Generation capacity factor trace
Musselroe	0.4245
NET George Town_WIND	0.4244
NWT Burnie_WIND	0.4086
ST Derby_WIND	0.3819
ST Waddamana_WIND	0.3819
Woolnorth	0.4249

CHAPTER 9 - UNITS OF MEASURE AND ACRONYMS

Units of measure

The following sections list the units of measure and acronyms used throughout this report.

Abbreviation	Unit of measure
GWh	Gigawatt hour
GW	Gigawatt
kA	Kiloamp
kV	Kilovolts
MVA	Megavolt amperes
MW	Megawatts
MWh	Megawatt hours
MW.s	Megawatt seconds
TWh	Terawatt hours
$	Australian dollars

Acronyms

Abbreviation	Expanded name
AC	Alternating current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGC	Automatic generation control
APR	Annual Planning Report
ASEFS	Australia Solar Energy Forecasting System
AWEFS	Australia Wind Energy Forecasting System
CCGT	Combined-cycle gas turbine
DGIF	Doubly fed induction generator
ESOO	Electricity Statement of Opportunities
FCAS	Frequency control ancillary services
FCSPS	Frequency Control Special Protection Scheme
GCS	Generation Control Scheme
HVDC	High voltage direct current
IRPC	Inter-regional Planning Committee
INTWG	Inter-network Test Working Group

Abbreviation	Expanded name
LRET	Large-scale Renewable Energy Target
MLF	Marginal loss factor
MMS	Market Management System
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NER	National Electricity Rules
NS	Non-scheduled
NTNDP	National Transmission Network Development Plan
OCGT	Open-cycle gas turbine
OFGS	Over-frequency generator shedding
PASA	Projected Assessment of System Adequacy
PCC	Point of common coupling
POD	Power oscillation damper
POE	Probability of exceedance
PSA	Power System Adequacy (two-year outlook)
PSS	Power system stabiliser
PV	Photovoltaic
QNI	Queensland Interconnector
REC	Renewable Energy Certificate
RET	Renewable Energy Target - national Renewable Energy Target scheme
RoCoF	Rate of change of frequency
SCR	Short-circuit ratio
SRMC	Short-run marginal cost
SS	Semi-scheduled
ST PASA	Short-term Projected Assessment of System Adequacy
SVC	Static VAR compensator
TNSP	Transmission network service provider
UFLS	Under-frequency load shedding