Power system dynamic security assessment with high penetration of wind generation in presence of a line commutated converter DC link

By

Derek Keith Jones BE(Hons)

Transend Networks

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Abstract

Traditionally energy has been generated with large synchronous generators. These large plants have characteristics that are well understood and are the basis for the operation of the electricity grid. Most grid codes are based on the assumption that new plant will be composed of synchronous generators. Most of these plants are powered by non-renewable fuels that come with significant carbon emissions. The realisation that there is not an infinite supply of these fuels and their emissions are harming the world's environment has resulted in policies being implemented aiming at reducing these sources of emissions. This energy is to be replaced with energy from renewable sources.

There are many renewable generator types available but wind generation has the highest focus in most countries. As of 2013 there is approximately 318 GW of wind energy installed worldwide.

Integrating all of this wind generation into the synchronous power system presents many challenges to grid companies. Wind generation usually does not have the same characteristics as synchronous plant as it is asynchronous. Many of the services that are assumed to be provided by synchronous plant such as inertia or fault contribution are unavailable or come with additional cost. Compounding this wind generation will displace synchronous plant, reducing the system strength further.

It is important for grid companies to gain an understanding of the impact of wind generation on the electrical system before the wind integration becomes an issue. Usually when issues begin to arise it is too late to alter existing plant. This means any mitigation of system issues will be expensive or result in an inefficient market. This means that new generators would be required to meet much higher connection standards as there is little system strength left to allocate to the new generators.

Ireland has tacked this integration issue by adopting a simple wind integration metric System Non Synchronous Penetration (SNSP) to flag when the system is approaching critical non-synchronous generation levels.

This thesis aims to investigate wind generation integration issues in small power systems, in particular ones that are not connected or only weakly connected to other larger grids. It will:

- Develop a wind integration metric similar to that used in Ireland or determine application guidelines for the Irish SNSP;
- Determine what regulatory approach may reduce the impact of new wind generation minimising the requirement for the integration metric; and
- Determine what effect wind generation may have on other plant, particularly those that will not be mitigated by the first two points.

For this study the power system of Tasmania is used as the case study. Tasmania is a relatively small (~1700 MW peak load, ~900 MW minimum load) power system connected weakly to the much larger mainland Australia power system via a single HVDC interconnector. This interconnector has a transfer capability of 500 MW into Tasmania and 630 MW out of Tasmania. Additionally this connector is monopolar and can lose all transfer capability in a single fault. This means that during low load approximately half of Tasmania's generation needs to be able to be tripped at any moment. This is before any response from wind farms is taken into account.

Tasmanian generation is predominantly hydro. This type of plant is very flexible. It can be started and shut down very quickly and has no real minimum operating level. This means that when wind generation is high it will tend to shut down rather than operate at a minimum level.

This thesis is presented in five sections:

Chapter 1. Introduction:
: This chapter introduces this thesis and its objectives. It also summarises the experiences of other jurisdictions and how they may be similar to the study case.

Chapter 2. Mathematical description of a wind plant:
: This chapter describes a wind plant in mathematical terms, and then it shows how a wind plant responds differently to grid disturbances.

Chapter 3. Impact of wind generation on a small power system:
: This chapter studies the impact of wind generation on the case study power system and investigates how this impact may be mitigated.

Chapter 4. Conclusion:
: This chapter summarises this thesis and explains its outcomes.

Abbreviations

AC	Alternating Current
CCGT	Combined Cycle Gas Turbine
DC	Direct Current
DENA	Deutsche Energie-Agentur
DFIG	Doubly Fed Induction Generator
ESCOSA	Essential Services Commission of South Australia
FERC	Federal Energy Regulatory Commission
FRT	Fault Ride Through
GE	General Electric
GW	Gigawatt
HVDC	High Voltage Direct Current
IGBT	Insulated Gate Bipolar Transistor
LCC	Line Commutated Converter
LVRT	Low Voltage Ride Through
ms	millisecond
MW	Megawatt
MWh	Megawatt Hour
MWs	Megawatt Second
NEM	National Electricity Market
NPCC	Northeast Power Coordinating Council
PSS/E	Power System Simulator for Engineers
pu	Per unit
SNSP	System Non Synchronous Penetration
UFLS	Under Frequency Load Shedding
USA	United States of America
VSC	Voltage Source Converter
WSAT	Wind Security Assessment Tool

Symbols

$\frac{\partial \omega}{\partial t}$	the rate of change of frequency
B_{sm}	the turn viscous coefficient
C	the capacitance of the DC bus capacitor
Cp	the power coefficient
$c_{wind\text{-}loss}$	the wind loss factor
E	the energy stored in the mass
E_o	the initial energy stored in the rotating mass of the system
E_{rem}	the remaining energy
Exp_{HVDC}	the total energy export through HVDC interconnectors
$Flux$	the flux of the generator
i_g	the grid side converter dc current
Imp_{HVDC}	the total energy import through HVDC interconnectors
i_s	the generator converter DC current
i_{sd}	d axis current of the generator
i_{sd}	d axis inductance of the generator
i_{sq}	q axis current of the generator
i_{sq}	q axis inductance of the generator
J	the moment of inertia of the mass
J_{eq}	the moment of inertia of the generator, blades, and gearbox
L_g	the inductance between the converter and grid
$Load$	the instantaneous demand on the system
$N_{gen,max}$	the maximum number of synchronous machines that can supply a load
n_p	the number of generator poles
P_{cont}	the contingency size
P_f	HVDC flow
P_{gen}	the synchronous generation
P_{HVDC}	the response of the HVDC
P_{loss}	the power loss through the disturbance
P_{min}	the minimum stable generation output
P_s	the output power of the generator
P_{sps}	the average load lost as part of the special protection scheme
P_t	the amount of load tripped in the SPS
P_{wind}	the initial wind farm output
$P_{wind\text{-}loss}$	the power loss due to wind farm fault ride through response
R	the radius swept area of the blades
R_g	the resistance between the converter and grid
R_{sa}	the stator resistance
t	the time after the event
T_{se}	the electromagnetic torque produced by the generator
t_{sps}	the operating time of the SPS
T_w	the input torque to the generator
u_{dc}	the dc voltage
V_w	the wind velocity
$Wind$	the instantaneous total output of all wind generators in the system
γ	the tip velocity ratio
λ_0	the flux from the permanent magnet
μ_{sd}	d axis voltage
μ_{sq}	q axis voltage

ρ	the air density
ω	the rotational speed of the mass
ω_o	the initial rotational speed of the system
ω_{se}	the electrical angular frequency
ω_{sm}	the mechanical speed of the generator
θ	the blade pitch angle

Publications

The author of this thesis has published three conference papers. These are detailed below:

[1] D. Jones, S. Pasalic, M. Negnevitsky and M. Haque, “Determining the frequency stability boundary of the Tasmanian system due to voltage disturbances,” Powercon conference, Auckland, 2012.

[2] D. Jones, M. Negnevitsky, S. Pasalic and M. Haque, “A comparison of wind integration metrics in the Tasmanian context,” Universities Power Engineering Conference (AUPEC), 22nd Australasian, Bali, 2012.

[3] D. Jones, “Determining the Technical and Economic Impact of Reconfiguring a Transmission System,” Australasian Universities Power Engineering Conference, (AUPEC), Hobart, 2013.

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Declarations

This thesis contains no material which has been accepted for a degree or diploma by the University or any other institution, except by way of background information and duly acknowledged in the thesis, and to the best of my knowledge and belief no material previously published or written by another person except where due acknowledgement is made in the text of the thesis, nor does the thesis contain any material that infringes copyright.

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The research associated with this thesis abides by the international and Australian codes on human and animal experimentation, the guidelines by the Australian Government's Office of the Gene Technology Regulator and the rulings of the Safety, Ethics and Institutional Biosafety Committees of the University

Signed Derek Jones:___________ Date: ___________

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Chapter 1 Introduction

1.1 Background

Traditionally energy has been generated with large synchronous generators. These large plants have characteristics that are well understood and are the basis for operation of the electricity grid. Most grid codes are based on the assumption that new plant will comprise synchronous generators. Most of these plants are powered by non-renewable fuels that come with significant carbon emissions. There is a limited supply of these fuels. The realisation that their emissions are harming the world’s environment has resulted in policies being implemented aiming at reducing these sources of emissions. This energy is to be replaced with energy from renewable sources. As of 2012 at least 118 countries have renewable energy targets [1].

There are many renewable generator types available but wind generation has the highest focus for new installations. As of 2012 there is approximately 238 GW installed capacity of wind energy worldwide. Approximately 40 GW of this was installed in 2011 [1]. This development trend will most likely continue due to wind generation’s competitive price compared with other forms of renewable energy.

Wind generators often have quite different characteristics to synchronous plant. They often have a power electronic grid interface. This is used to maximise energy harvested from the wind by varying the speed of the machine with wind speed [2]. This power electronic interface is inherently much more controllable than a synchronous machine. This means the wind turbine operator can choose to (or not to) present synchronous machine characteristics such as inertia and fault contribution. Generally existing wind turbine operators choose not to present these services to reduce the cost of the generator and increase the energy harvested from the wind. This can present issues operating a system with large amounts of wind generation.

A wind plant can have several impacts on the stability of the electrical system. It can reduce the critical clearance time of faults depending on the types of wind turbines used [3]. A fixed speed (induction generator) wind turbine particularly can degrade the fault performance.

Small power systems often present greater challenges for wind integration than larger systems. The response characteristics of the wind generation are felt much sooner. The largest event that can happen often represents a larger percentage of the total size of the system. In Australia, for example, the synchronous power system of the eastern mainland states (Queensland, New South Wales, Victoria, and South Australia) has a largest contingency of 780 MW on a power system of over 20 GW (~4% installed capacity) compared with the small power system of Tasmania that is less than 2 GW and has a largest contingency of 480 MW (more than 24% installed capacity).

If the small power system is connected to a larger power system the wind penetration can increase more rapidly. This is because wind farms may be built primarily to supply the larger connected system, but will build where there a good wind resource in the smaller system. If the interconnector to the larger system is weak (or a single circuit only) there will be significant periods where the system will need to operate without support.

This thesis aims to analyse the effect wind generation can have on these smaller power systems. It will determine what issues they may face and will determine what methods may be adopted to allow for additional wind generation.

The island of Tasmania is presented as a case study. It has a smaller power system with around 1700 MW peak demand. It is connected to mainland Australia via a monopole HVDC link with 630 MW export, 480 MW import capability. This line-commutated link requires a certain amount of synchronous generation to ensure its thyristors operate correctly. Fig. 1-1 shows the location of Australia and Tasmania on the world map.

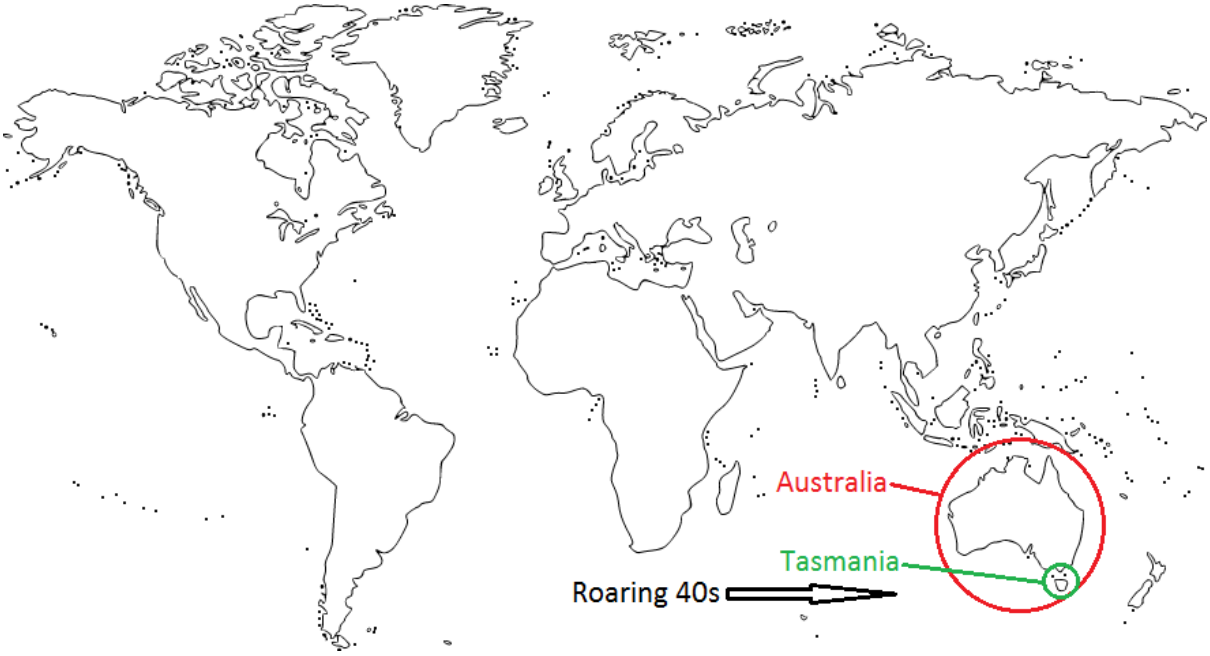

Fig. 1-1 Australia and Tasmania on the world map

Up to 1,540 MW of wind is predicted in Tasmania [4]. The primarily hydroelectric generation in Tasmania can switch off readily as it can be restarted quickly. This further weakens the system as when wind generation is high the hydro plant will switch off, particularly when water storages are low.

Tasmania thus makes an ideal example system as it represents all of the issues that are common to small power systems:

- The largest single contingency is a large percentage of the power system;
- Synchronous generation is easily displaced at times of high wind generation; and
- It is predicted to have large wind generation integration in the future.

Before studying the test system in detail the experiences of others should be considered. These can inform the solutions adopted for this work.

Other countries and states of Australia have had considerable experience integrating wind generation. The experiences of these other jurisdictions are useful in gaining an understanding of the issues a small power system may face and what may be done to mitigate these issues.

In many cases the experiences of system operators in integrating wind generation is embodied in their grid codes for connection [5].

1.2 International experiences

1.2.1 China

The current world leader for installed wind generation capacity is China. As at the end of 2011 China had around 62.4 GW of installed wind capacity [1]. This is an increase of 17.6 GW over the previous year. China's goal is to have 100 GW of installed capacity by 2020 [6].

Much of the non-wind generation in China is coal fired (75.9% in 2007) or hydroelectric (21.6% in 2007) [7]. Coal generation accounts for 82.8% of all energy generated.

China's peak load is around 500 GW [8]. This is a large system compared with Tasmania which has a peak demand of less than 2 GW. Much of China's wind capacity is located distant from load centres and requires long transmission lines to interconnect with load centres [7]. In this sense Tasmania's case can be seen to have some parallels with China's in that much of Tasmania's wind generation would need to be transported to mainland Australia or to Tasmania's load centres.

Wind turbines in China are often manufactured locally and are often not equipped with low voltage ride through[1] capability [7].

The capacity factor of installed wind farms in China has been lowered considerably by an insufficient transmission network to transport the generation coupled with large scale development of wind farms. This is caused by lack of coordination between the issuing of permits for building wind generation and the expansion of the transmission network [7], [9], [10].

Some more recent studies have indicated that wind farm variability can cause a significant decline in frequency adequacy indices. These indices relate to the power system's ability to maintain its frequency. This requires an increase in dispatched reserve or in extreme cases manual intervention by system operators [11]. In some cases it is observed that the frequency deviation due to wind farm variability is of similar magnitude to that of loss of a large generator.

Although the Chinese system has a large amount of wind generation it is still somewhat different to a small power system. It is has a much higher demand (250 times the peak demand of the Tasmanian case study). The largest generators are very small compared with the size of the power system. This reduces magnitude of frequency deviations caused by loss of a major generator. The size of the grid also leads to an insulating effect where remote portions of the grid will not be affected by a contingency. At a certain distance from a fault wind farms will not be affected by the disturbance. Additionally the generation mix is quite different with a large amount of coal-fired thermal generation. This thermal plant is much less variable than other types because its only capacity constraint is the rate at which coal can be extracted or shipped to the furnace and the fact that once turned off it is slow to restart.

The planning issues in China are related to the amount of wind generation built in a short time. In other power systems with a much slower growth of wind generation, the network

[1] Low voltage ride through relates to a wind turbine's ability to ride through grid faults

infrastructure is generally able to keep up with generation growth. Without the large incentives to build, a wind farm will generally not build without a network connection.

The large Chinese power system is much larger than the system that this thesis analyses. The issues to be studied are therefore likely to be quite different.

1.2.2 North America

The United States also has seen large amounts of wind generation constructed in recent years, with 60 GW of installed capacity in 2012 [12]. This generated 3.23% of all electrical energy requirements from August 2011 to July 2012 [12]. The leading state by capacity is Texas with 12,212 MW of installed capacity.

Around 13 GW of wind energy was commissioned in the USA in 2012. The growth rate of wind energy in the USA is expected to slow with several tax breaks for wind farms having expired at the end of 2012. At the end of 2012 there was only 47 MW of wind generation under construction [12].

The total United States energy consumption during 2012 was 3,686,780 MWh. The peak demand was 760 GW in summer 2011 [13].

Studies by the USA Department of Energy have determined that 20% wind penetration is possible in the USA grid. This will require increased investment in transmission and distribution networks and increased complexity in the electricity market [14]. This study contended that with large amounts of dispersed wind generation the level of reserves required to counter wind variability is significantly less than the increase from a single plant alone. This is because of the statistical effects of the independently varying wind plant. This study indicated that this variability may add around $0.50/MWh to the cost of energy. Some states in the USA already surpass 20% of wind generation penetration, for example 22% of electricity generation in Iowa in 2011 [12].

Another study of the north-eastern USA grid has shown that 10% wind generation integration would lead to a decrease in locational marginal prices (LMP) [15].

The Northeast Power Coordinating Council (NPCC) has determined that increased wind generation could lead to increased congestion (periods of insufficient transmission capacity) and thus affect the locational prices [16]. These contradictory outcomes indicate that the effect of wind generation can be highly variable and difficult to model correctly.

Wind generation effects on frequency control in the USA have recently become a larger issue [17]. This is often caused by a de-commitment of synchronous plants where for every 3 MW of wind generation on average there is a 2 MW reduction in synchronous plant output and a 1 MW reduction in dispatch (i.e. 1 MW of thermal generation is switched off). This study has concluded that use of advanced controls such as wind inertia and primary frequency control can actually improve system response over a system with no wind generation.

Texas is a slightly different case to the rest of the USA. It has the largest amount of wind generation in the USA and it is operated as an asynchronous system (i.e. there are no synchronous links to the rest of the USA). Wind generation penetration in Texas has exceeded 25% [18].

Integration of this amount of wind generation has required a series of reforms to the market structure. This has required the transition from a zonal to a nodal electricity market in Texas.

The first issues observed were areas of local transmission congestion caused by wind generation. This was initially addressed with assigned capacity rights to wind generators. The zonal market caused the energy prices in generating areas to reduce and load areas to increase when congestion occurred.

Another issue observed was a lack of balancing reserves to cover for changes in load during a 15 minute dispatch interval. Wind generators were initially exempt from providing 'down balancing' services required of other generators. This led to insufficient reserves and frequent negative market prices due to the amount of down balancing services required. This issue was addressed by requiring wind generators to offer down balancing services. Wind variability has been shown to be not correlated with load variability and hence requires additional frequency control reserves over that which is dispatched for load variability.

Quebec is operated similarly as an isolated system (without synchronous links). It is hydro dominated with over 85% of its generation from large hydroelectric schemes in the far north. This requires long 745 kV AC or HVDC interconnectors to transmit this generation to load centres. These interconnectors are installed along two primary way leaves leaving them vulnerable to tripping due to extreme weather events [19].

Recognising these grid issues has resulted in Hydro-Québec having strong requirements for voltage, frequency, and disturbance ride through since 2005. This was a result of proposals to increase wind generation from 110 MW to 1350 MW by 2012 [19].

In the North American power systems there are several different grid codes. In the USA the standards for interconnection of wind and alternative generators are defined by the Federal Energy Regulatory Commission (FERC) order 661-A issued in December 2005 [20]. This standard makes several requirements for wind generation. These are described below:

- Wind power plants must stay in service during three phase faults cleared with 'normal clearing' (4-9 cycles (66-150ms)) and single line to ground faults with 'delayed clearing' (undefined in the standard) with a subsequent voltage recovery to the post fault voltage level. The voltage is allowed to drop to zero during a 'normal fault'.
- Wind power plants are required to maintain their power factor within a range of 0.95 leading to 0.95 lagging if a transmission service provider's system impact study shows this to be required.
- Wind power plants are required to provide supervisory control and data acquisition (SCADA) capability to transmit critical plant parameters. Which parameters are to be telemetered is left to the judgement of the transmission service provider.

These standards were written in 2005 which is a long time ago for wind technology. At this time grid features such as Low Voltage Ride Through (LVRT) and voltage control were still in their infancy and not available with all wind turbines. It is up to the transmission services provider to prove reactive power is required. During a fault the wind plant is expected to remain in service, even if the voltage drops to zero. The plant is not, however, required to recover in any particular time, or take any action to recover the voltage.

Hydro-Québec TransÉnergie requires wind generation plants to meet the same technical requirements as synchronous plants with several supplementary technical requirements [21]. The basic requirements for connection of plant are as follows:

- The maximum loss of generation following a single contingency is 1000 MW.
- The connection point voltage, in steady state, can be allowed to vary by up to ±10%, depending on connection voltage.
- The system frequency, in steady state, can vary by up to ±1%.
- The plant must be able to ride through faults of types and durations given in Fig. 1-2, for the voltages in Fig. 1-3.
- The wind plant must be able to ride through frequency ranges given in Table 1-1.
- Wind plant must be able to ride through a rate of change of frequency of 4Hz/sec.
- Wind plant greater than 10 MW must have a voltage regulation system:
  - That can present a power factor at the connection point of 0.95 leading or lagging;
    - Unless the interconnection study shows that this power factor is not required, but may not be less than 0.97;
  - Have a permanent droop adjustable between 0 and 10%;
  - That is capable of this performance with a voltage range of 0.9-1.1pu;
    - Lagging power factor is not required when voltage is 0.9pu;
    - Leading power factor is not required when voltage is 1.1pu;
  - That is capable of this performance in relation with the number of wind generators in service.
- Wind power plant greater than 10 MW must have a frequency control system that reduces large short duration frequency events at least as much as does the inertial response of a conventional synchronous generator whose inertia equals 3.5s.
- Wind power plants must have an adjustable maximum ramp rate between 2-60 minutes from 0 MW-PMAX or from PMAX-0 MW.
- Wind plants must be built to gradually shut down over a minimum of 1-4 hours when wind or temperature forecasts indicate they must shut down.
- Wind power plants must be equipped with a stabiliser.

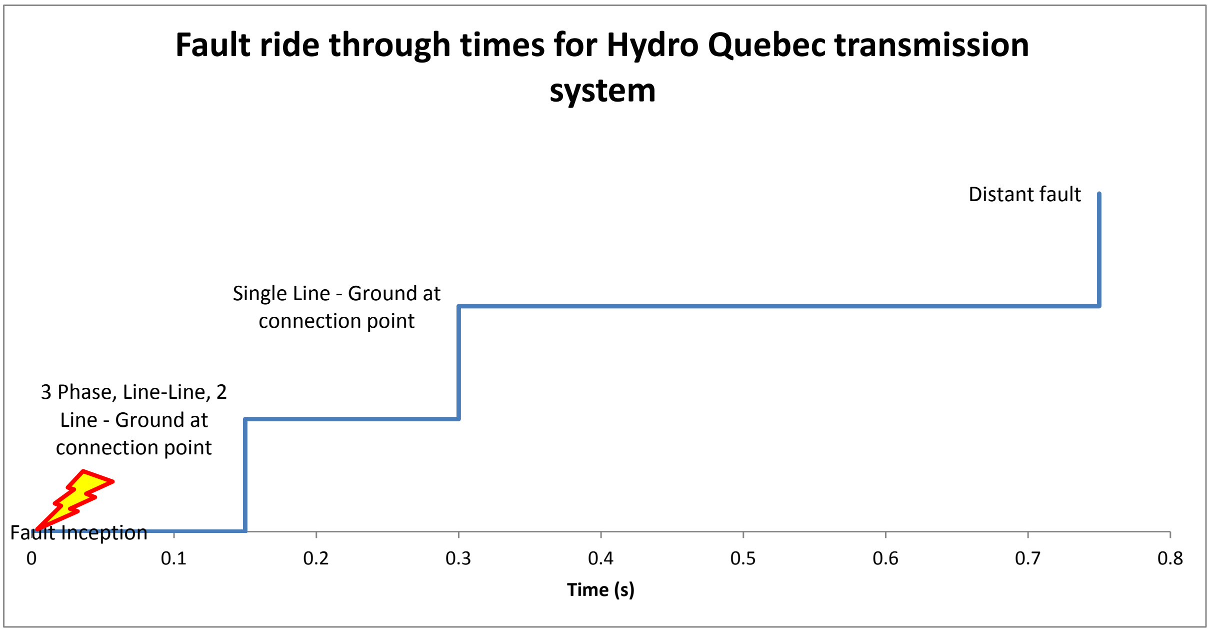

Fig. 1-2 Fault ride through times for Hydro Quebec TransÉnergie transmission system

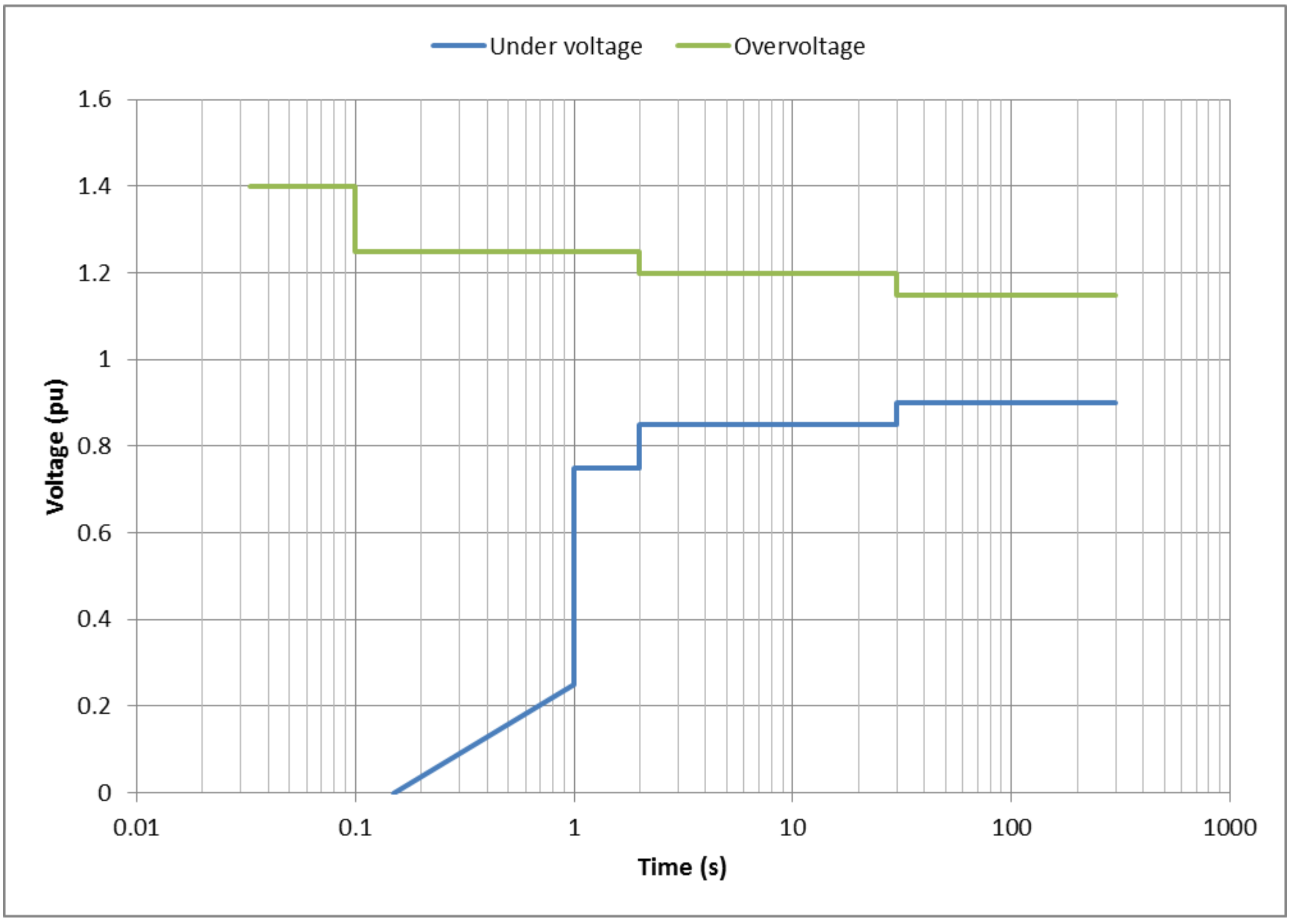

Fig. 1-3 Voltage ride through requirements for Hydro Quebec TransÉnergie transmission system [21]

Table 1-1: Frequency standards for wind plant in Quebec [21]

Under-frequency	Over-frequency	Time
59.4-60 Hz	60-60.6 Hz	Continuous
58.5-59.4 Hz	60.6-61.5 Hz	11 minutes
57.5-58.5 Hz	61.5-61.7 Hz	90 seconds
57.0-57.5 Hz		10 seconds
56.5-57.0 Hz		2 seconds
55.5-56.5 Hz		350 milliseconds
55.5 Hz +	61.7 Hz +	instantaneous

The Quebec grid code places fairly high requirements on wind farms connected to its grid. The voltage and frequency ride through requirements are essentially the same for asynchronous and synchronous plant. This standard is an interesting contrast to the USA FERC requirements which generally loosen requirements significantly for wind plant. This can perhaps be related to the difference in the conditions in which wind plant connects in the two jurisdictions. In the USA wind plant is usually built by private enterprise with the intention of making income through energy sales. These proponents usually object to any requirement that places more equipment in their plant as it impacts on their profit. In Quebec the wind plant is built in response to a call for tenders from Hydro Quebec. In this case Hydro Quebec, as the ultimate client, can set the requirements to ensure the response is ideal from a grid viewpoint.

1.2.3 Germany

Germany is another world leader in wind energy generation, with 31,332 MW of installed capacity at the end of 2012. 2,439 MW of this was installed in 2012 [22]. This is also coupled with strong PV growth due to incentives to consumers to install PV panels. This has led to more than 32,300 MW of installed capacity of PV panels at the end of 2012 [23]. On 24/03/2013 more than half of Germany's instantaneous electricity demand was generated by a combination of wind and solar resources [24].

Studies have indicated that the observed change in wind power output in Germany can reach more than 2.5 GW per hour, with a deviation between the day ahead wind forecast of up to 7 GW [25]. This occurred in 2007 when wind generation in Germany was 22.1 GW. Wind generation was mainly found to affect the tertiary reserves (those with an activation time of several minutes). This study has indicated that load response may be valuable in reducing the integration costs of wind energy.

With the known issues regarding integrating wind energy into the system, two major studies were commissioned by the German energy agency DENA (Deutsche Energie-Agentur), one in 2005 [26] and one in 2010 [27]. The 2010 study is the more relevant as it is more recent. This study assumed over 75 GW of renewable energy would be installed by 2020. Significantly this study's target of 17.9 GW of solar energy installed by 2020 has already been nearly doubled. These studies have indicated that to achieve Germany's target of 35% renewable energy by 2020, significant grid expansion is required. The 2005 study suggested that 850 km of grid expansion by 2015 would be required to integrate 20% renewable energy by 2020. By the 2010 study only 90 km had been built. The more ambitious target for the 2010 study indicated that over 3000 km of new grid transmission lines would be required by 2020. This would require a significant increase in transmission investment over current levels. The total grid enhancements required is expected to cost nearly €1 billion per annum (approx. AUS $1.56 billion per annum).

The 2010 DENA grid study found that there was significant non transmittable energy during periods of high wind generation. This study investigated the effects of adding freely operating (i.e. market driven) energy storage to the power system. This study found that energy storage operated on a market basis does little to relieve congestion as the storage will tend to generate during periods of high congestion when prices are high.

Demand side management was expected to contribute approximately 60% of the demand for positive balancing energy and 2% of the demand for negative balancing energy by 2020 in the 2010 DENA grid study. This demand management changes energy use by less than 0.1% of total demand and results in a reduction in peak load supplied by gas power plants of 800 MW. This reduces the costs of electricity generation by €418 million per annum by 2020.

The 2010 DENA study indicated that an average of 4,200 MW of positive regulating power and 3,300 MW of negative regulating power[2] would be required by 2020. This is essentially the same as what is required currently. This is primarily due to increasing forecast accuracy removing the expected additional requirements. Also wind turbines were shown to be able to provide significant negative balancing energy by 2020. Positive balancing energy, which requires wind turbines to operate at partial capacity and waste some incoming wind energy, was shown to be cost efficient in a few situations only.

Although more modern wind turbines are able to remain connected to the system during grid faults, a general reduction in system security was observed in the DENA 2010 grid study. This was due to lack of short circuit power and voltage control. These issues were able to be controlled with additional reactive support devices and through connections to neighbouring countries that have more synchronous generation, but it was also suggested that wind turbines should be made more like synchronous machines.

Overall the DENA study has indicated that it is possible to integrate large amounts of renewable energy into the German grid. This will require some changes to how the grid and wind farms operate, and a significant capital works program to enhance grid capacity.

Another study has analysed the wind integration costs of Germany and several other Scandinavian systems. This study determined that the integration costs are lower for systems with large amounts of hydroelectricity such as Norway and higher for systems that are dominated by thermal generation such as Germany [28].

Germany's solar generation has increased rapidly over recent years, exceeding even its wind generation. This is compounded by most of this solar generation being integrated at lower voltage levels and in smaller amounts, making control more expensive – and more importantly not required under most grid codes. This has resulted in several phenomena that reduce grid quality or endanger grid security [29]. These include reverse power flows, overloading of grid elements, and grid stability.

[2] Regulating power in the German context is used to regulate frequency

With such a large amount of solar energy integrated in a short time it can take time for grid codes to evolve to meet the rising challenge. A recent case of this was 'the 50.2-Hz risk' in Germany [29]. This risk was introduced by the German grid code having a fixed upper frequency cut off for PV inverters of 50.2 Hz. This caused essentially all connected PV generation to disconnect simultaneously with a grid frequency of 50.2 Hz. With 30 GW of installed solar generation this could cause a grid issue, as the grid wide system reserve is only 3000 MW. This, in the German case, resulted in a change of grid codes requiring solar inverters to gradually ramp back power injection between 50.2 Hz and 51.5 Hz. Additionally up to €175 million must be spent retrofitting 315,000 existing solar plants.

The lack of controls on these distributed inverters also causes voltage control problems. Many of the existing inverters have no reactive power capability, or even ability to modify their active power output in response to voltage. This leads to high voltages during sunny days [29]. This does not necessarily require communications to fix, just inverters to have some voltage control and active or reactive power modulation capability [29].

Germany has no single grid operator; instead there are four separate operators. This split of grid operators also results in different grid codes for each, however all grid operators must meet the same grid standards [30].

The E.ON[3] grid code requires renewable generation plant to meet all requirements for synchronous plant with several specific requirements. These requirements are in the areas of active power output, frequency stability, and restoration of supply. All requirements are in terms of basic requirements and additional requirements. All plant must meet at least the basic requirements and may be required to meet the additional requirements if the grid operator deems it necessary.

The E.ON grid code requires renewable energy plant to maintain its active power output for frequencies down to 47.5 Hz. Above 50.2 Hz, plant must reduce its active power output at a rate of 40%/Hz until the frequency returns to 50.05 Hz. Renewable plants are not required to provide frequency control.

Power factor in the E.ON grid code can very between 0.925 over-excited and 0.95 under-excited. This requirement however is modified by the grid voltage. Over-excited requirements drop at high voltages and under-excited requirements drop at low voltages.

During a fault the E.ON grid code requires some fault current in-feed from renewable (asynchronous) generators. The amount of in-feed is agreed with the grid operator.

The renewable energy plant must disconnect after 0.5 seconds if it is absorbing reactive power and the voltage at its connection point is less that 85%. At the low voltage side of the generator transformer the generator(s) must disconnect in stages if the voltage falls below 0.80 pu, with blocks of 25% of the plant disconnecting every 0.3 seconds after 1.5s. Above 1.2 pu the plant disconnects in 100ms. Additionally all plant must remain connected to the grid during and after a fault. Active power must be restored at the rate of at least 20% of the rated power per second after the fault.

[3] E.ON is one of the major public utility companies in Europe and the world's largest investor-owned energy service provider

Renewable energy generators are not required to black start the system.

The German wind grid code appears to fall somewhere in the middle. It does not require frequency control services as per the Quebec grid code, but has much firmer requirements than the FERC code.

1.2.4 Ireland

Ireland is an islanded power system in Europe that has seen a vastly increased level of wind generation in recent years with 2109 MW of installed capacity in Ireland and Northern Ireland [31]. The peak demand in the all island system is around 5 GW. The Irish and northern Irish system has two HVDC interconnections to the United Kingdom. The older Moyle interconnector, commissioned in 2001, has a capacity of 500 MW and uses thyristor (line commutated) technology. The newer East-West interconnector, commissioned in 2012, has a capacity of 500 MW and uses newer insulated-gate bipolar transistor (IGBT) based voltage source converters (VSCs). Both links are bipolar.

Wind generation in Ireland began to expand rapidly after the European Union targets for renewable energy (RES-E directive) were adopted. This has led to the grid code being altered to account for this generation [32].

The Irish energy market operator, EirGrid, has implemented several mechanisms to integrate this wind generation. This lead initially to a simple operational metric called *System Non-Synchronous Penetration* (SNSP) [33]. This metric is in Eq (1.1) [33].

$$SNSP = \frac{Wind + Imp_{HVDC}}{Load + Exp_{HVDC}} \tag{1.1}$$

where: *Wind* is the instantaneous total output of all wind generators in the system; *Load* is the instantaneous demand on the system; Imp_{HVDC} is the total energy import through HVDC interconnectors; Exp_{HVDC} is the total energy export through HVDC interconnectors.

This metric attempts to link system stability to wind generation through its ratio to load. If wind generation is high compared with load (i.e. SNSP is low) then it is likely that there will be little synchronous generation running. This is likely to mean a weaker system as synchronous generation is primarily what gives system strength.

The Irish study team indicated that an SNSP of over 50% could lead to system instability. This was primarily due to Rate of Change of Frequency relays installed on wind farms. These relays are intended to trip the wind farm if they become 'islanded' – i.e. they are left as the sole generators with a group of load.

If the Rate of Change of Frequency relays were disabled the Irish study indicated an SNSP of 75% would be achievable. Above 75% SNSP it is much more likely that the frequency after a disturbance would drop below 49 Hz and cause under frequency load shedding.

As wind penetration has increased further a more complex system called Wind Security Assessment Tool (WSAT) has been implemented [34]. This tool dynamically assesses system security through a series of online dynamic and load flow studies. This provides an on-line real-time varying indication of the amount of wind the system can support

The Eirgrid grid code has specific generator connection provisions for wind generators [35]. These provisions cover performance characteristics including fault ride through, frequency, and voltage control. This grid code also specifies which connection conditions for synchronous generators a wind generator must also meet. Most of these relate to general design requirements. The performance of the plant is governed by the wind specific sections.

The Eirgrid grid code requires generators to ride through voltage disturbances down to 15% of nominal (at the connection point) for 625 ms.

Additionally during the disturbance the wind plant must:

- Provide active power in proportion to retained voltage; and
- Provide reactive power within the remaining plant capability; and

The wind plant must also recover to 90% of its available active power within 1 second after the voltage recovers.

Wind plant are expected to remain generating for a frequency range of 49.65 Hz to 50.5 Hz. Between 47.5 Hz and 52.0 Hz they must remain connected for 60 minutes, but there is no requirement to generate. Similarly plant must remain connected between 47.0 Hz and 47.5 Hz for 20 seconds. Generators must also ride through a rate of change of frequency of 0.5 Hz/second, and must block connection of additional plant above 50.2 Hz.

Particularly interesting is the requirement that wind plant must have an active power response. This response is governed by a characteristic given in the grid code. This characteristic is shown in Fig. 1-4.

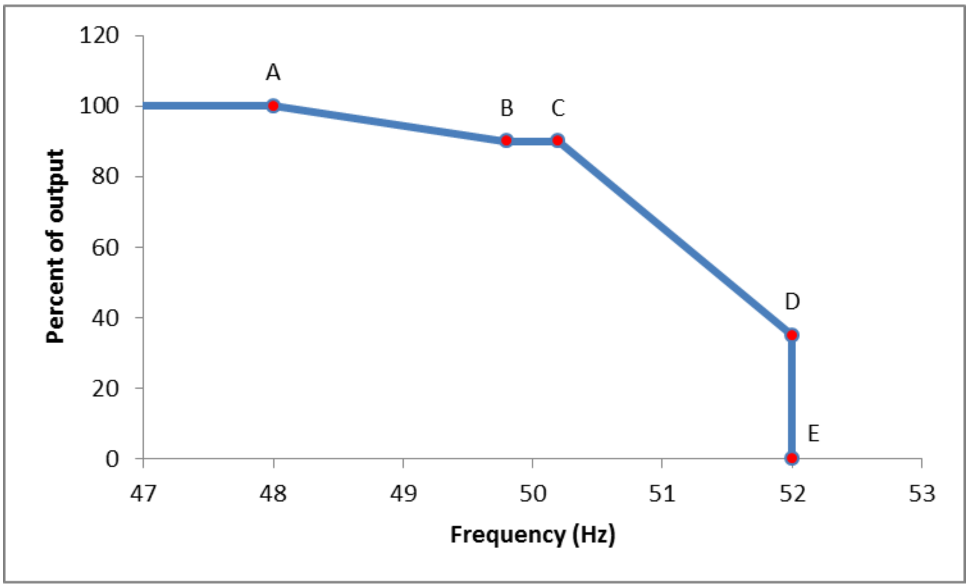

Fig. 1-4 Eirgird frequency control requirements [35]

The wind plant is required to spill wind in system normal conditions. This remaining energy is held in reserve for low frequency events. Note that the locations of points ‘A’, ‘B’, ‘C’, ‘D’, and ‘E’ are nominated by the transmission system operator. This allows this frequency response to be disabled by the selection of these points.

1.2.5 Summary of international experience

Many of the larger power systems have experienced issues of wind generation variability and its impact on balancing reserves and frequency regulation. This issue however is observed later in the smaller power systems. It is expected that contingency frequency control is likely to be an issue first in smaller power systems.

Even some larger power systems such as that of Germany are beginning to experience frequency control problems with integrating a large amount of power electronic generation. In Germany solar inverters have been required to be retrofitted with more graded frequency ride through capabilities. This indicates the importance of setting requirements before excessive integration of renewable generation. Later retrofitting is much more expensive than if the plant is already equipped with the desired capabilities.

The Irish power system has had good experience as it is a smaller power system. To mitigate the effects of wind generation a simple wind integration metric has been implemented that indicates the system's proximity to instability in real-time.

The grid code requirements for wind plant vary significantly between jurisdictions. Some, such as the USA grid code, significantly reduce requirements for wind plant over synchronous plant. Others such as Quebec or Ireland require wind response that is similar to or even better than a synchronous plant. This is particularly in the domain of frequency control that wind farms have traditionally not participated in.

1.3 South Australia

South Australia is not a national jurisdiction like others discussed here. It is worthwhile discussing however because many of its experiences are applicable as the South Australia system is relatively weakly connected to the rest of the Australian power system. South Australia is connected to the wider National Electricity Market (NEM) via a single double circuit 275 kV AC transmission line and a small HVDC interconnector known as Murraylink. Recently a project has been approved to increase the capacity of this HVDC interconnector [36]. When one of the two transmission lines connecting South Australia to the rest of the Australian power system is out of service (due to maintenance for instance) the system must be operated such that it can be islanded from the rest of the power stem.

Also of note is that South Australia operates under the same rules as the rest of Australia (The National Electricity Rules[4]). The method in which it has applied these rules to ensure system security is applicable to other systems which are small parts of larger power systems.

South Australia currently has the greatest concentration of wind energy generation in Australia, with 1203 MW of installed capacity as of August 2012 [37]. Peak demand in 2012-13 summer was 3,125 MW [38].

South Australia is part of the larger Australian National Electricity Market. NEM-wide the wind energy generation share is much lower at around 2% of energy penetration [39]. The 650 MW

[4] Ref http://www.aemc.gov.au/Electricity/National-Electricity-Rules/Current-Rules.html

synchronous (AC) interconnector has a much lower capacity than installed wind generation. This means that most of this energy must be absorbed locally.

Wind generation is predicted to reach nearly 3,500 MW in South Australia by 2020 [40]. This is predicted to lead to an hourly variability of wind generation of over 900 MW [40]. South Australia's interconnection to the rest of the NEM allows this variability to be more easily absorbed and this level of variability is not seen as an issue. South Australia is predicted to see increased network congestion with this additional wind generation, particular in the Eyre Peninsula, and in the south-east part of the state [41].

This additional wind generation will have a significant market impact in South Australia. High wind generation coupled with low interconnector capacity will tend to lead to lower prices. If generation is high enough the price will collapse [41]. It is generally difficult to justify network augmentation in this scenario as there is little market benefit in relieving the congestion due to the low price. This makes it less likely the constraint will be relieved [41].

South Australia has two main sets of rules that define how a wind plant may connect to the network. These are:

- The National Electricity Rules
- The Essential Services Commission of South Australia (ESCOSA) licence conditions

The National Electricity Rules (NER) applies all over Australia, not just South Australia. In these rules, section S5.2.5 provides the conditions under which a generator may connect to the grid [42]. These standards apply to synchronous and non-synchronous generation. These rules cover several aspects of generation including:

- Reactive power capability;
- Harmonics and distortion;
- Frequency and voltage disturbance ride through characteristics;
- Protection (for faults internal and external to plant);
- Frequency and active power control;
- Voltage and reactive power control; and
- Impact on other parts of the network (e.g. interconnector capability).

Each standard has two separate levels of access:

- **Automatic access**: If a generator meets the automatic access standard connection cannot be denied on the basis of this standard; and
- **Minimum access**: If a generator cannot meet the minimum access standard connection cannot be granted.

If a plant cannot meet automatic access a standard between automatic and minimum access is negotiated between the proponent of the plant and the network service provider that is mutually acceptable to both.

The automatic access standard is generally fairly 'grid friendly'. A generator meeting automatic access for reactive power for example must be able to present a power factor between

0.93 leading and lagging at its connection point. Conversely the minimum access standard is somewhat less stringent. The minimum access standard has no requirements for reactive power capability at the connection point.

Generally wind plant proponents will attempt to connect at the lowest standard possible as this is the cheapest. In response, the network service provider must prove that the higher standard is required. This can be problematic for plant characteristics that are undesirable, but not a problem for a specific plant. This makes it progressively harder to connect new plant to the network.

Realising that this is a problem ESCOSA has presented a series of additional requirements for plant to connect to the South Australian grid. These standards are couched in terms of the NER and specify minimum negotiated access standards in the areas of:

- Fault performance; and
- Reactive power capability.

These standards essentially require automatic access performance in these areas. In particular the reactive power capability clause requires at least 50% of this reactive power capability to be ‘dynamic’.

These additional standards are generally not well accepted by wind farm proponents [43]. This increases the cost to connect and at certain connection sites this may not be required.

Other states in Eastern Australia (Victoria, New South Wales, Queensland, and Tasmania) do not have wind grid connection codes.

1.4 Summary of international and Australian experience

Many countries have had valuable experiences which can be drawn upon when guiding a strategy for wind integration in a small power system.

- Many countries have experienced issues with the rate of change of wind power output. This causes issues with regulation services, causing inefficient market outcomes such as higher prices or increased congestion. Additionally several grid codes require forecasting and gradual shut down if this is forecast to be required.
- Fault ride through has caused issues in many jurisdictions. Faults are much more severe if large amounts of wind generation are lost simultaneously. Most jurisdictions now have fault ride through requirements that at least require wind plant to remain generating through standard disturbances.
- Some parts of the world are experiencing frequency control issues with large amounts of wind generation. This has prompted various control strategies. Quebec requires inertia-like response from wind plant while Ireland requires frequency control (i.e. requires the plant to spill wind). Additionally in Ireland the SNSP security metric has been used to determine in real-time how much wind generation the system can support.
- Many studies have indicated significant grid expansion is required to support the large amounts of forecast wind generation. This expansion often lags the wind

generation commissioning significantly. It is easy to write a report recommending significant expenditure, but much harder to justify and implement this plan.

- Often a wind specific ‘grid code’ is applied. This grid code is sometimes stricter than the standard code, but also sometimes less strict. This code is used to govern the quality of plant that connects to the grid. Some, such as the South Australian grid code, require significant reactive power. Some, such as the Quebec grid code, require inertia. The USA grid code is somewhat different in that it significantly reduces the requirements for wind generators.

The approach adopted depends significantly on the issues experienced in the particular jurisdiction. It is unlikely that one grid code in particular can be adopted without modification for Tasmania.

The rest of this thesis investigates which, if any, of these grid codes may be applicable to a small power system.

1.5 Problem Statement

With respect to the international experiences mentioned in the preceding chapters the problem this work is attempting to investigate is:

What issues are likely to be introduced in a small power system with increased wind generation? What can be done to control these issues with minimal investment?

1.6 Project objectives and research overview

The objectives of this project are:

- Develop a wind integration metric similar to that used in Ireland or determine application guidelines for the Irish SNSP;
- Determine what regulatory approach may reduce the impact of new wind generation minimising the requirement for the integration metric; and
- Determine what effect wind generation may have on other plant, particularly those that will not be mitigated by the first two points.

The work will primarily be performed using system studies in Power System Simulator for Engineers (PSS/E).

1.7 Thesis Outline

This thesis is divided into four chapters:

Chapter 1 summarises the thesis and describes the result of a review of international experiences.

Chapter 2 presents a mathematical description of a wind turbine then shows it’s response to standard system disturbance.

Chapter 3 shows the impact of wind genre5taion on a small power system and investigates how the issues may be mitigated.

Chapter 4 concludes the thesis by listing the outcomes and recommendations.

1.8 Publications

The author of this thesis has published three conference papers. These are detailed below:

[1] D. Jones, S. Pasalic, M. Negnevitsky and M. Haque, “Determining the frequency stability boundary of the Tasmanian system due to voltage disturbances,” Powercon conference, Auckland, 2012.

[2] D. Jones, M. Negnevitsky, S. Pasalic and M. Haque, “A comparison of wind integration metrics in the Tasmanian context,” Universities Power Engineering Conference (AUPEC), 22nd Australasian, Bali, 2012.

[3] D. Jones, “Determining the Technical and Economic Impact of Reconfiguring a Transmission System,” Australasian Universities Power Engineering Conference, (AUPEC), Hobart, 2013.

Chapter 2 Mathematical description of a wind plant

2.1 Introduction

Before studying issues related to wind integration it is important to understand the reasons a wind turbine acts like it does. This can be done by analysing the mathematical relationships that govern their operation, and then the wind farm's response to real-world system events can be studied. This can be used to determine how a wind farm may behave differently to synchronous plant.

2.2 Mathematical description

In developing these equations reference [44] is used as the primary reference.

The basic structure of a 'full converter' (type 4) wind turbine model is shown in Fig. 2-1.

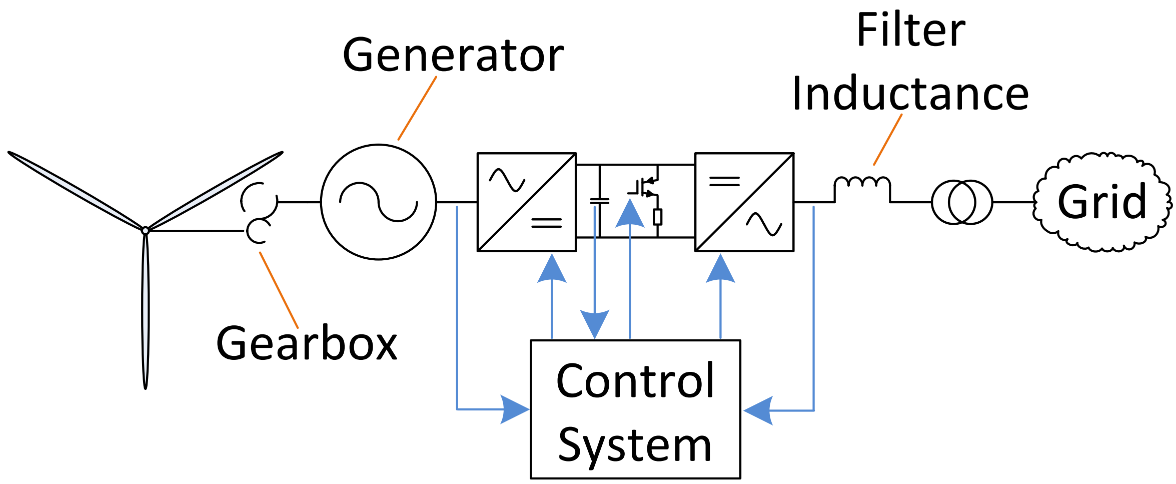

Fig. 2-1 Basic model of a wind turbine [44]

In a full converter wind turbine such as this the entire power output of the generator is converted from AC to DC and back to AC again. This decouples the frequency of the generator from the frequency of the grid, allowing the rotation speed of the turbine to be adjusted to maximise power output. This also protects the generator from grid disturbances.

The energy is extracted from the wind because it exerts a torque on the blades of the wind turbine. This torque can be related to the wind speed by (2.1) [44].

$$T_w = 0.5\rho\pi R^3 V_w^2 C_p(\theta,\gamma)/\gamma \tag{2.1}$$

where: T_w is the input torque to the generator; ρ is the air density; R is the radius swept area of the blades; θ is the blade pitch angle; γ is the tip velocity ratio; V_w is the wind velocity; and *Cp* is the power coefficient.

As can be seen in this equation, a wind turbine designer has several tools at his disposal to increase a wind turbine's power output. The most obvious one is to increase R – the length of the wind turbine's blades. This evolution can be traced through history. The early wind turbines of the 1980s had turbine blades of approx. 10m length and power outputs of around 100 kW. Current wind turbines can have turbine blades of approx. 82m length and power outputs of 8 MW.

The second way that a wind turbine's power output may be altered is by adjusting C_p. C_p is a function of blade pitch angle and tip velocity ratio. Modern wind turbines can control both of these. Blades are equipped with active pitching systems, and the back to back power converter discussed earlier allows the tip speed ratio to be adjusted.

In this particular model the generator is a permanent magnet synchronous generator. This removes the need for the machine side converter to supply reactive power. The differential equations describing the permanent magnet generator in the rotating d and q reference frame are given in (2.2) [44] and (2.3) [44].

$$\frac{di_{sd}}{dt} = -\frac{R_{sa}}{L_{sd}} i_{sd} + \omega_{se} \frac{L_{sq}}{L_{sd}} i_{sq} + \frac{1}{L_{sd}} \mu_{sq} \tag{2.2}$$

$$\frac{di_{sq}}{dt} = -\frac{R_{sa}}{L_{sd}} i_{sq} - \omega_{se} \left(\frac{L_{sd}}{L_{sq}} i_{sq} + \frac{1}{L_{sq}} \lambda_0 \right) + \frac{1}{L_{sq}} \mu_{sq} \tag{2.3}$$

where: i_{sd} and i_{sq} are the d and q axis current of the generator; i_{sd} and i_{sq} are the inductance of the generator in the direct and quadrature axes. These are equal; R_{sa} is the stator resistance; ω_{se} is the electrical angular frequency; λ_0 is the flux from the permanent magnet; and μ_{sd} and μ_{sq} are the d and q axis voltages.

The electrical frequency of the rotor is related to the physical speed by the number of poles. This is described in (2.4) [44].

$$\omega_{se} = n_p \omega_{sm} \tag{2.4}$$

where: ω_{sm} is the mechanical speed of the generator; and n_p is the number of generator poles.

This number is selected to satisfy physical and mechanical requirements. The electromagnetic torque will act to oppose the torque from the wind turbine blades and can be described by (2.5) [44].

$$T_{se} = 1.5 n_p \left[\left(L_{sd} - L_{sq} \right) i_{sd} i_{sq} + i_{sq} \lambda_0 \right] \tag{2.5}$$

where: T_{se} is the electromagnetic torque produced by the generator.

This electrical torque counteracts the mechanical torque from the wind turbine blades through the gearbox of the wind turbine. The gearbox' dynamics can be presented using (2.6) [44].

$$\frac{d\omega_{sm}}{dt} = \left(T_{se} + T_{sm} - B_{sm} \omega_{sm} \right) / J_{eq} \tag{2.6}$$

where: J_{eq} is the moment of inertia of the generator, blades, and gearbox; and B_{sm} is the turn viscous coefficient.

The generator side converter is tasked with controlling the power output and speed of the generator and thus the blades. The power control at low wind speeds uses maximum power point tracking to extract the maximum power from the wind. At high wind speeds the torque angle is adjusted to maintain maximum power output. A simplified block diagram of this controller is shown in Fig. 2-2.

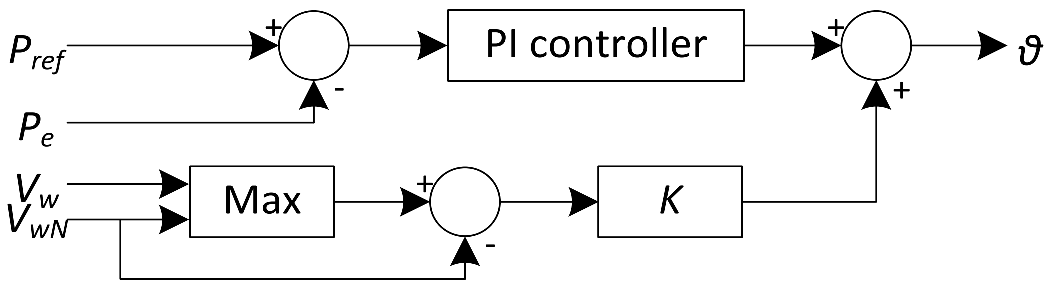

Fig. 2-2 Torque angle controller

The machine side converter also controls the speed of the machine. It does this by producing vector voltages u'_{sd} and u'_{sq}. By carefully selecting these voltages the interdependence of (2.2) and (2.3) can be removed. This is done using (2.7) [44] and (2.8) [44].

$$u'_{sd} = \omega_{se} L_s i_{sq} + u_{sd} \quad (2.7)$$

$$u'_{sq} = -\omega_{se} L_s i_{sd} - \omega_{se} \times Flux + u_{sq} \quad (2.8)$$

where: *Flux* is the flux of the generator.

These give the new independent equations (2.9) [44] and (2.10) [44].

$$u'_{sd} = (sL_s + R_{sa}) i_{sd} \quad (2.9)$$

$$u'_{sq} = (sL_s + R_{sa}) i_{sq} \quad (2.10)$$

The speed controller now becomes as shown in Fig. 2-3.

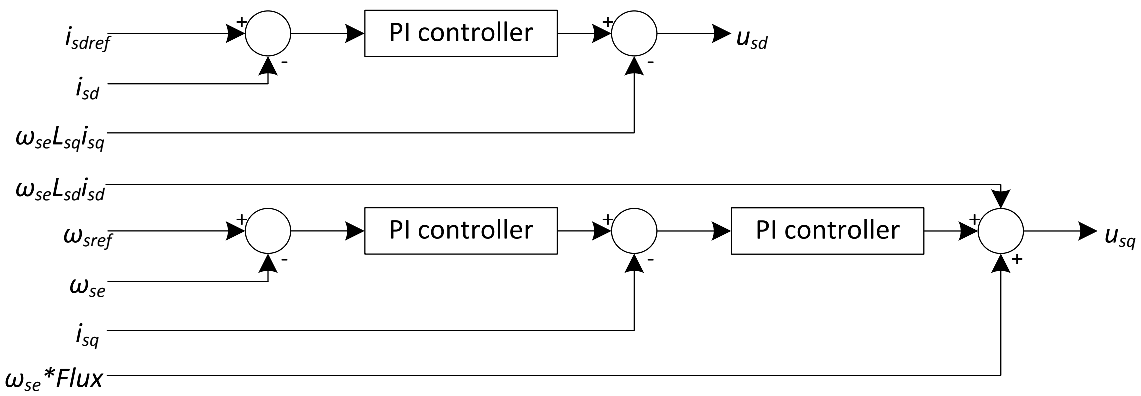

Fig. 2-3 Speed controller

The next section of this model is the DC link between the two converters. In steady state just a capacitor is here. This capacitor is primarily to regulate the DC voltage. Transiently a chopper or crowbar may be used - primarily during faults.

The equation of state of a capacitor is well known. It is shown in (2.11) [44].

$$C \frac{du_{dc}}{dt} = i_s - i_g \quad (2.11)$$

where: u_{dc} is the dc voltage; i_s is the generator converter DC current; i_g is the grid side converter dc current; C is the capacitance of the DC bus capacitor.

Assuming the machine side converter consumes no power the capacitor voltage can be expressed as in (2.12) [44].

$$C\frac{du_{dc}}{dt} = \frac{P_s}{u_{dc}} - i_g \tag{2.12}$$

Where P_s is the output power of the generator which can be related to the input torque by (2.13) [44].

$$P_s = \omega T_{se}. \tag{2.13}$$

The grid side converter is tasked with maintaining the DC bus voltage and controlling reactive power injection to the grid. Its control block diagram is shown in Fig. 2-4.

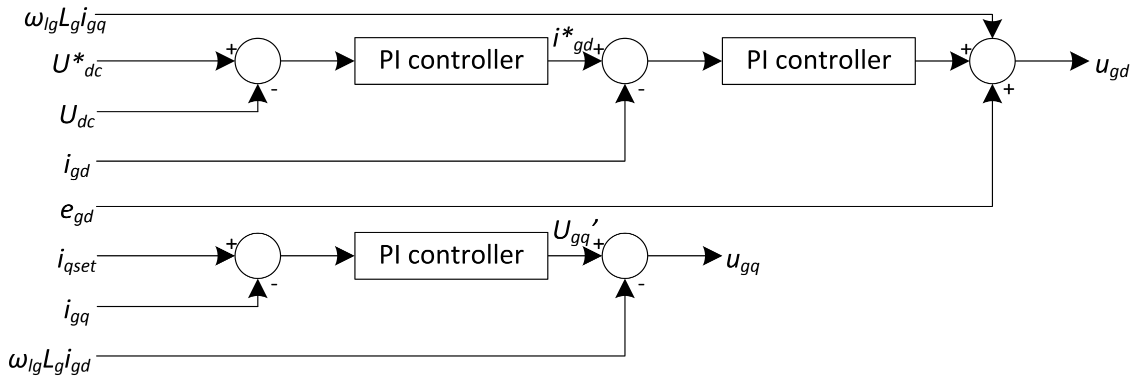

Fig. 2-4 Grid side converter block diagram

where: U^*_{dc} is the DC voltage set point; i_{gd} and i_{gq} are the d and q axis grid currents; ω_g is the angular frequency of the grid; L_g is the inductance of the grid filter; u_{gd} and u_{gq} are the d and q axis converter voltages; and e_{gd} is the d axis grid voltage.

The output voltage of the grid side converter can be expressed mathematically in (2.14) [44] and (2.15) [44] using the grid side d and q axis reference frame.

$$u_{gd} = -R_g i_{gd} - L_g\frac{di_{gd}}{dt} + \omega_g L_g i_{gq} + e_{gd} \tag{2.14}$$

$$u_{gq} = -R_g i_{gq} - L_g\frac{di_{qd}}{dt} + \omega_g L_g i_{gd} \tag{2.15}$$

where: R_g is the resistance between the converter and grid; and L_g is the inductance between the converter and grid.

The power produced by the grid side converter is then [44]:

$$P_g = 1.5\left(u_{gd}i_{gd} + u_{gq}i_{gq}\right) \tag{2.16}$$

$$Q_g = 1.5\left(u_{gd}i_{gq} - u_{gq}i_{gd}\right) \tag{2.17}$$

These simplified equations can give an understanding of the basics of wind turbine operation. Modern wind turbines however generally have a much more complex control mechanism. This would improve the response over this simplified turbine dramatically. For this study a generic wind turbine model provided by Siemens PTI has been used. This model represents the

General Electric family of wind turbines. These are both full converter (type 4) and doubly fed induction generator (DFIG) (type 3) wind turbines.

2.3 System response

Before understanding what issues wind generation may introduce it is important to understand how wind generation is different to synchronous plant generation. In this chapter the response of wind generators and synchronous plant are compared.

For this section a simplified system has been used. The general layout of the system is shown in Fig. 2-5.

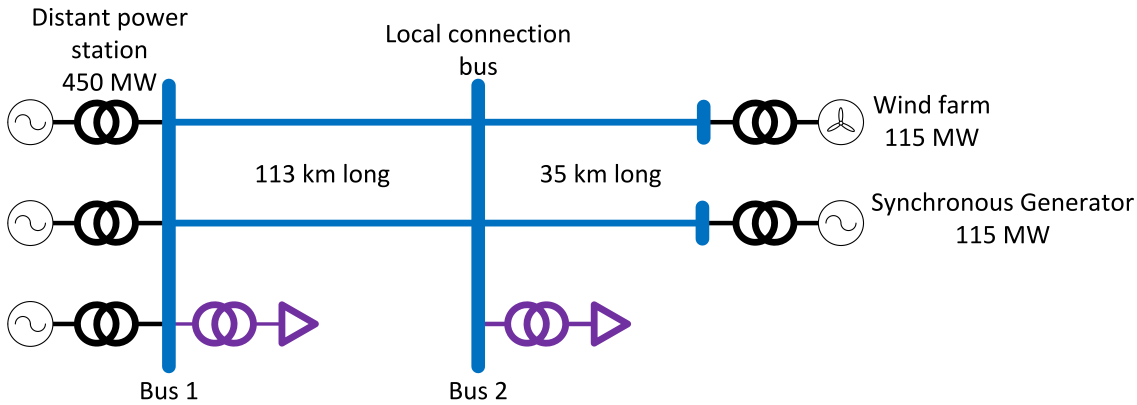

Fig. 2-5 Simple system single line diagram

Wind plant is modelled as per Appendix A.

The focus of this study will be the response to large disturbances such as faults. Small signal stability is a separate topic and is not considered here. Simulations have been performed using the positive sequence dynamics package of Power System Simulator for Engineers (PSS/E). This package does not study single phase faults explicitly; single phase faults are modelled as equivalent three phase faults. The model response therefore may not represent the actual plant characteristics well.

There are four fault types considered here:

- A fault close to the generator;
- A fault distant to the generator;
- Trip of a generator with no fault; and
- Trip of a generator with a fault.

These fault types represent the most common disturbances seen in a power system.

This section will show the differences between a wind plant and synchronous plant.

2.3.1 Close fault

The first comparison is to show how a wind and synchronous generator react to a close-in fault. In this fault, a 3 phase bolted fault is applied at bus 2 and cleared by tripping one line connecting bus 1 and 2.

Generally during a fault a generator will inject reactive power to attempt to restore the voltage. Initially this is involuntary as it is related to machine physics. Later this will be sustained by the machine's excitation system. A synchronous machine has significant overload capability as this is governed by the thermal inertia of the machine – it takes time for machine components to meet their maximum temperature during an overload. The fault current from a synchronous machine is typically several times its rating.

A wind generator has only a small involuntary reactive response. Generally most of the fault current is dictated by the controls on the machine converter. To prevent damage to the power electronics the current is limited to approximately the rating of the machine.

These different fault characteristics are shown in Fig. 2-6. The synchronous machine provides significant reactive power support during the fault and rapidly increases its reactive power post clearance to support the system. The wind farm provides no support during the disturbance. After the disturbance it returns to its pre fault output. The voltage controller then acts slowly to restore the voltage. In existing Tasmanian wind farms the rise time may be in the order of minutes.

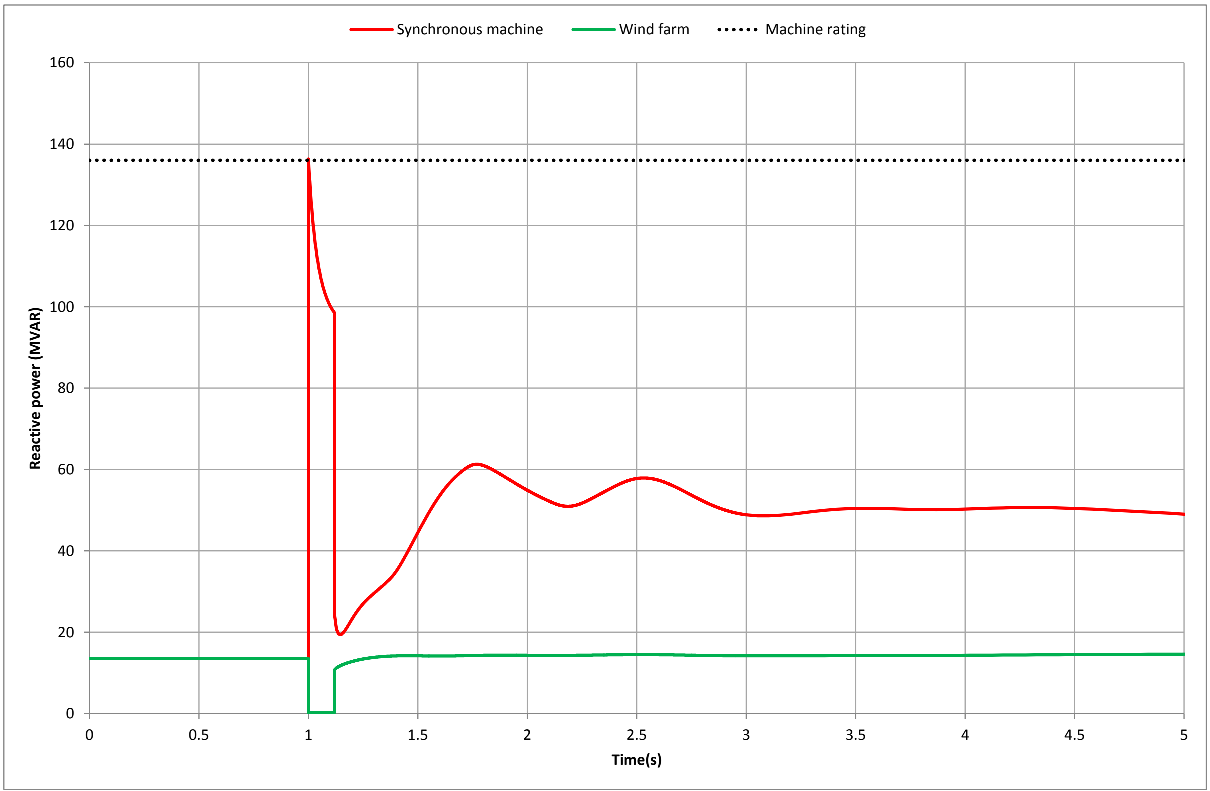

Fig. 2-6 Response of wind and synchronous generator to close fault

The differing response has a significant effect on the voltage performance. Fig. 2-7 shows the voltage performance at the machine terminals. The voltage at the wind farm's terminals sags by nearly 30% more than at the synchronous plants. After the disturbance the improved voltage control performance gives a faster and better recovery.

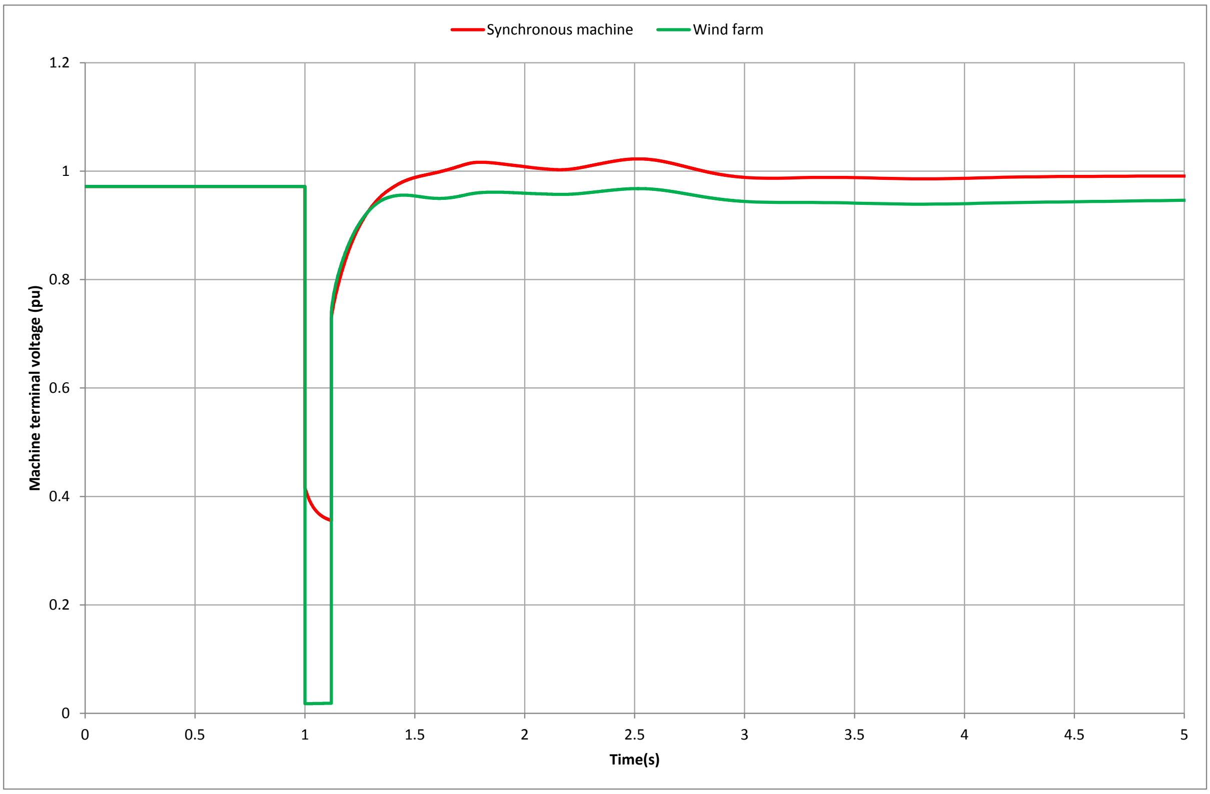

Fig. 2-7 Differing voltage performance of synchronous and wind generator

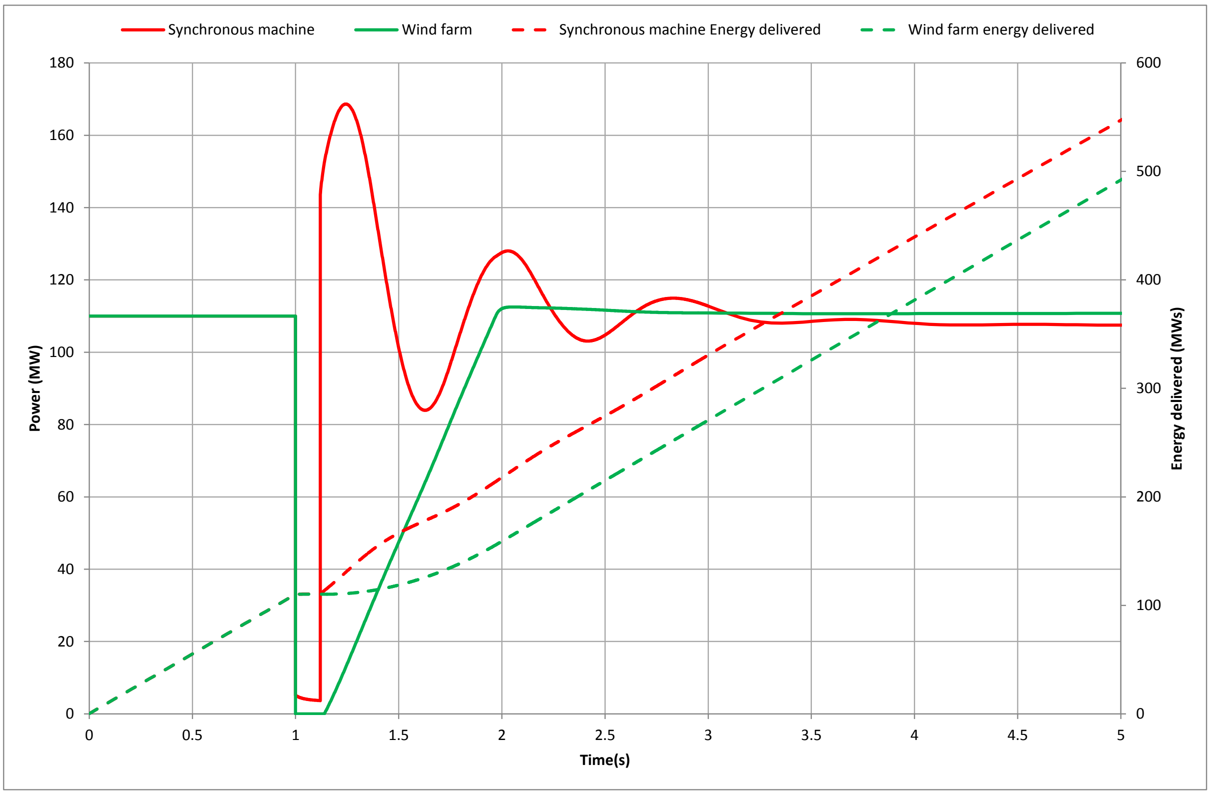

Fig. 2-8 Active power response to system disturbance

For this sort of disturbance active power is expected to change little. There is no load or generation lost, only a small change in the reactive losses of the system. The response is shown in

Fig. 2-8. The synchronous machine's active power recovers instantly with significant overshoot. This is due to the increase in load angle during the disturbance. The wind farm takes significant time to recover its active power after the disturbance. This results in an energy deficit of around 50 MWs after the disturbance. This is more than 10% of the synchronous machine's total inertia.

2.3.2 Distant voltage disturbance

The distant disturbance in this case is modelled by a fault on the load bus at bus 1. The voltage depression is much less severe. The reactive power response is shown in Fig. 2-9. The synchronous machine again has a strong response. The wind plant's reactive power output drops to zero and only begins to recover slowly due to the voltage controller. This could be an error in the wind model or an actual response characteristic. This does indicate however how important it is to have good controls on the wind turbine.

The active power response is shown in Fig. 2-11. Even though the fault is distant the active power from the wind farm drops to less than 10% of its initial value. The synchronous machine's active power only drops by around 20% and instantly recovers after the fault while dissipating the energy stored during the fault. The power deficit between the wind and synchronous generator is again around 50 MW.

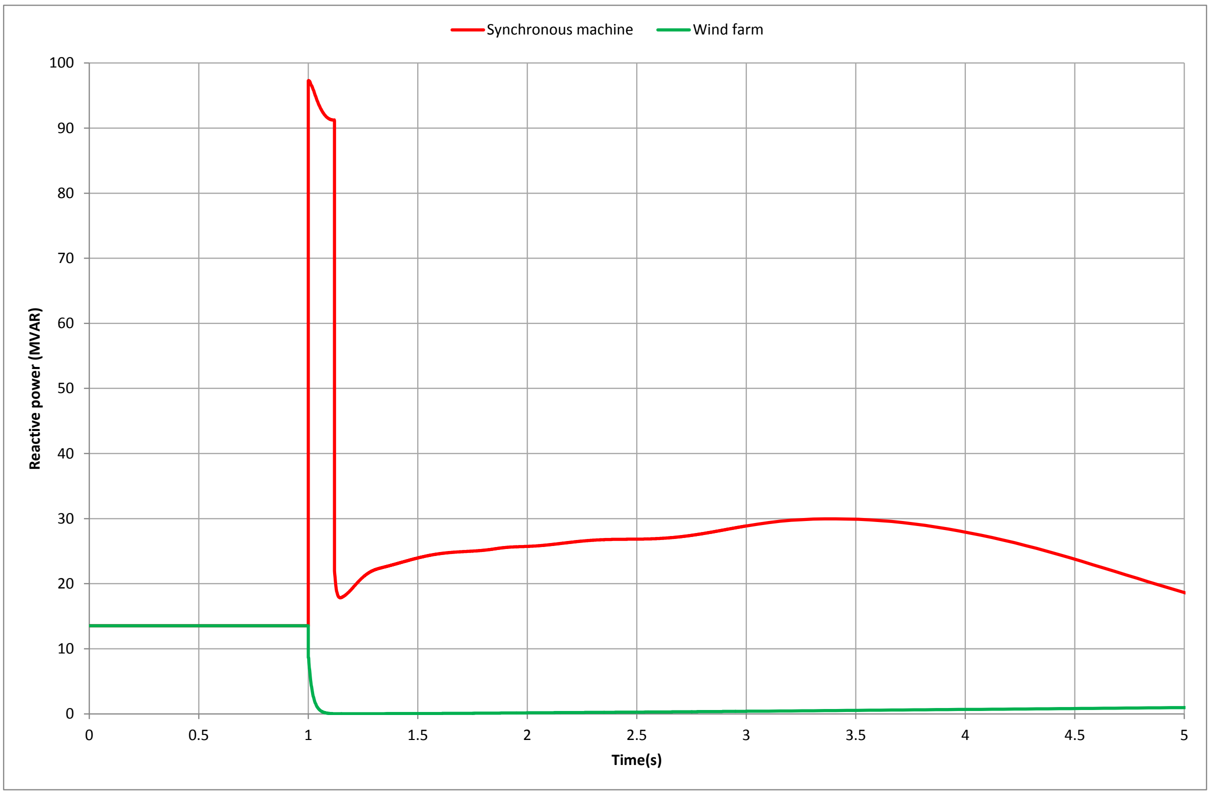

Fig. 2-9 Reactive power response to distant fault

Fig. 2-10 shows the difference in voltage response. During the fault there is a 15% decrease in terminal voltage. The reduced reactive power after a disturbance reduces the voltage significantly.

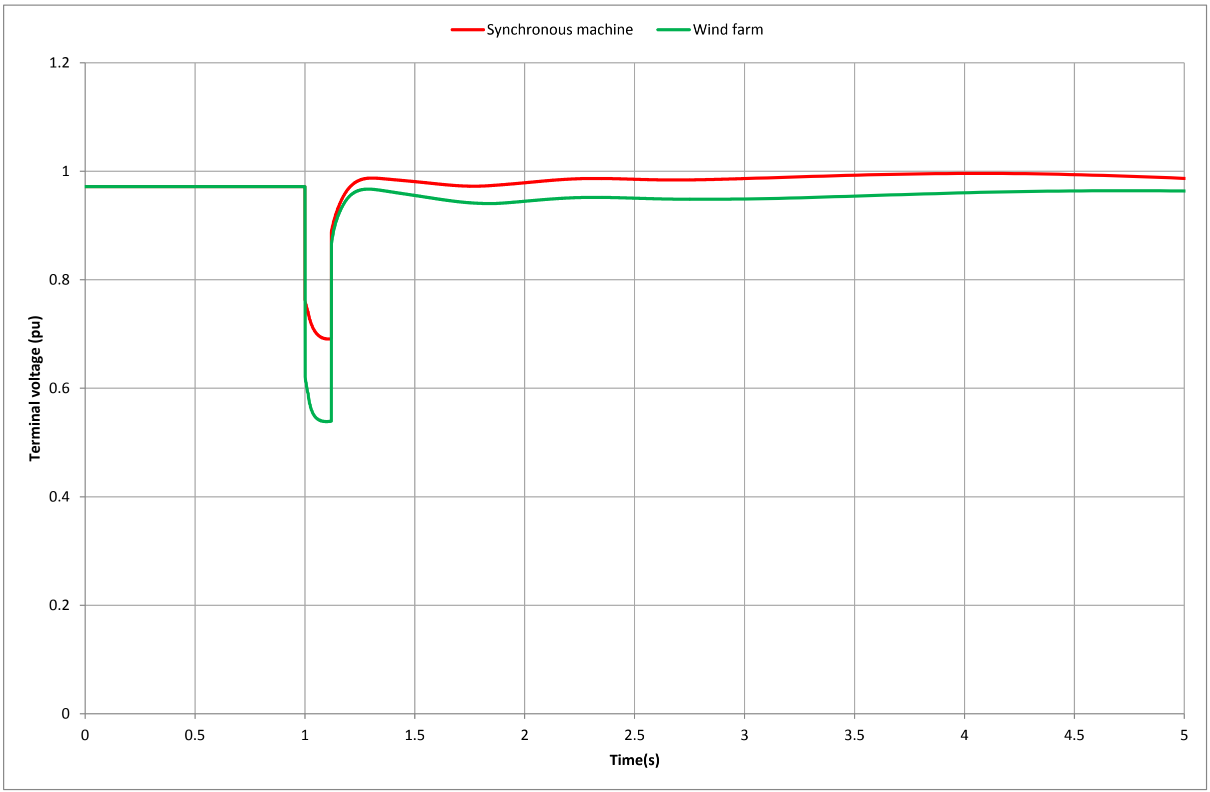

Fig. 2-10 Voltage response to distant fault

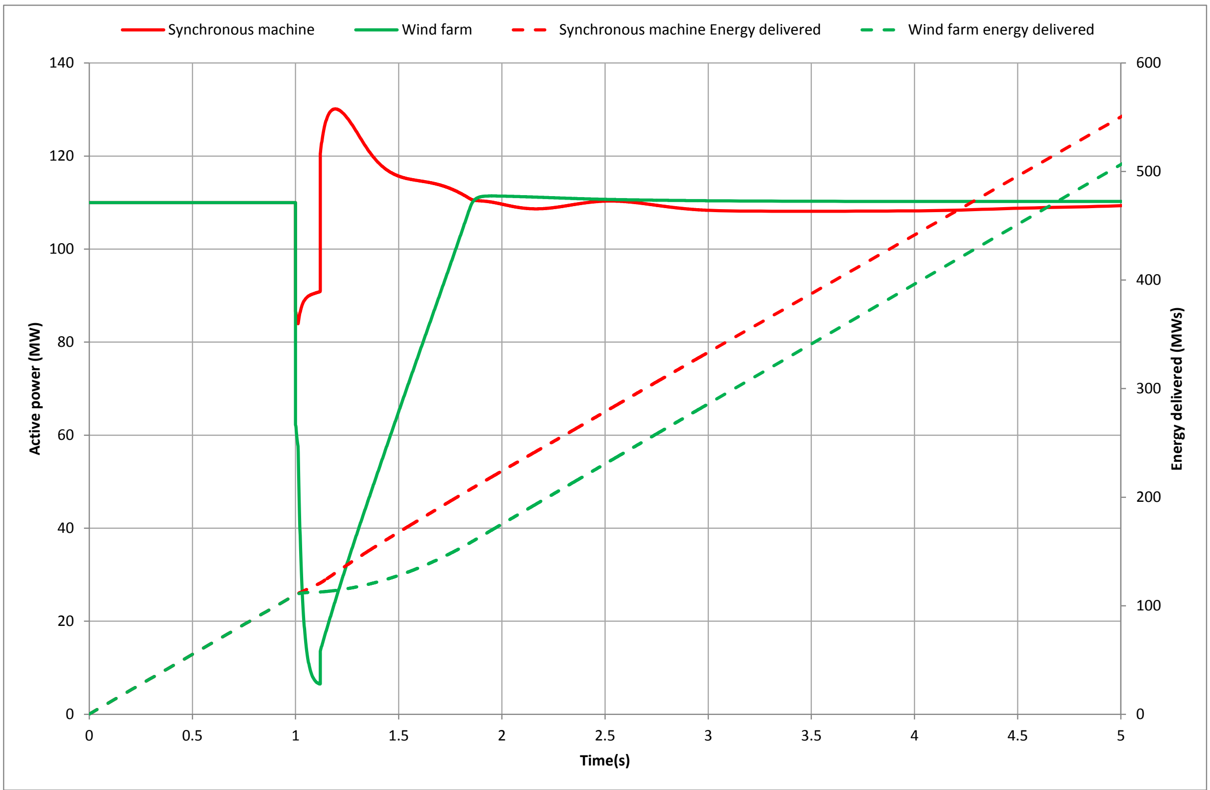

Fig. 2-11 Frequency response to distant fault

2.3.3 Loss of a generator

For loss of a generator with no preceding fault, primarily the active power response is important. The active power response is shown in Fig. 2-12.

The wind machine maintains a constant power input. It does not attempt to restore the frequency. The synchronous machine, as it is running close to its capacity primarily has an inertial response. The inertial response acts to slow the rate of change of frequency. It provides power into a declining frequency and draws power when it is increasing.

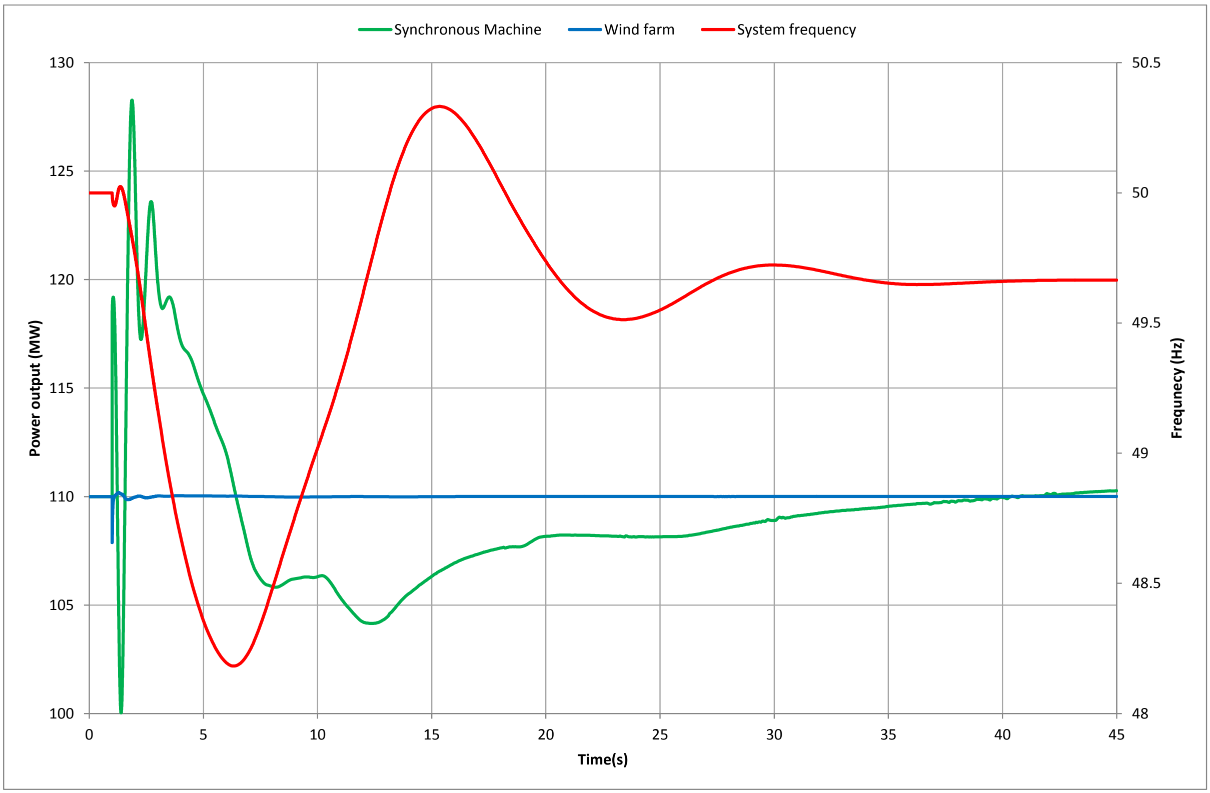

Fig. 2-12 Active power response to loss of a generator

2.3.4 Generator trip with initiating fault

As shown in 2.3.1 a wind plant will stop active power injection during a fault. If a disturbance does not result in a large frequency disturbance this is not usually a problem. It can become a problem when a generator is lost with an initiating fault. In this case the loss of active power can increase the apparent size of the generator fault. The frequency response to this sort of fault is shown in Fig. 2-13. The minimum frequency drops from around 48.25 Hz to around 47.4 Hz.

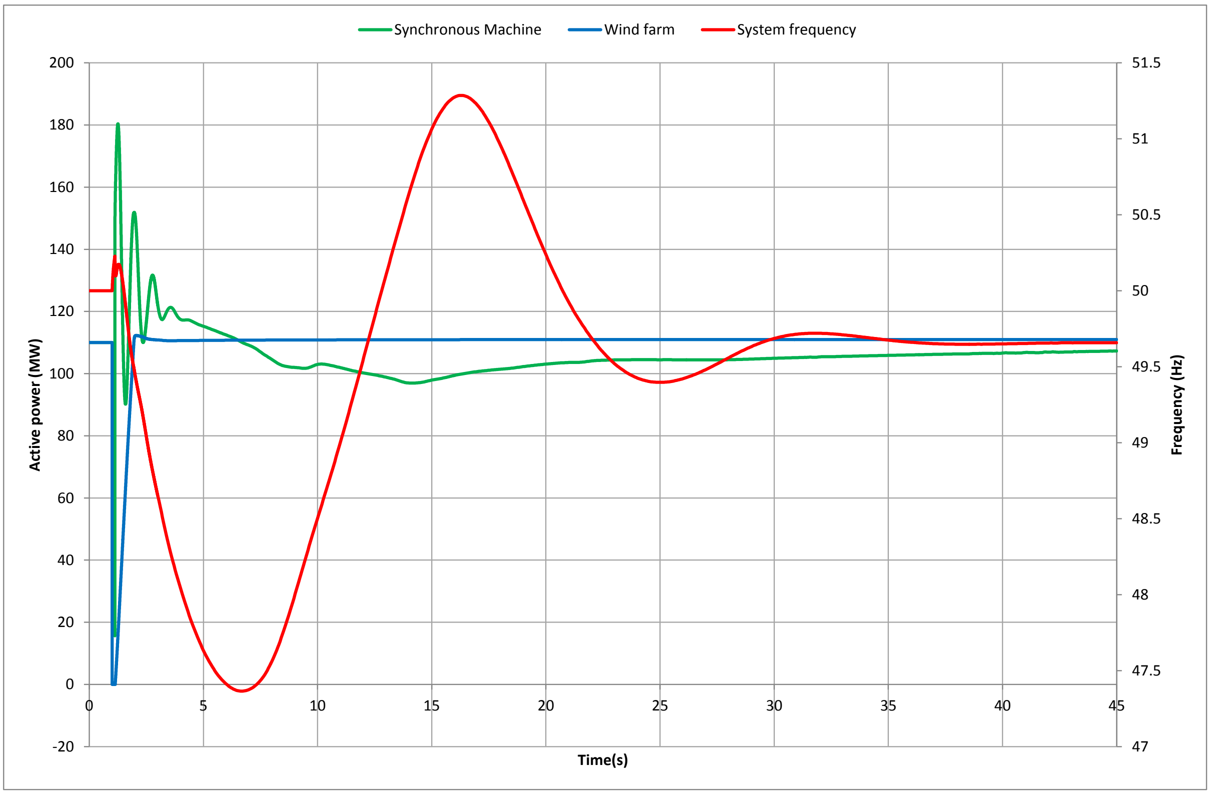

Fig. 2-13 Active power response to loss of a generator with initiating fault

The size of this effect is shown in Fig. 2-14 where the frequency response with and without a fault is compared.

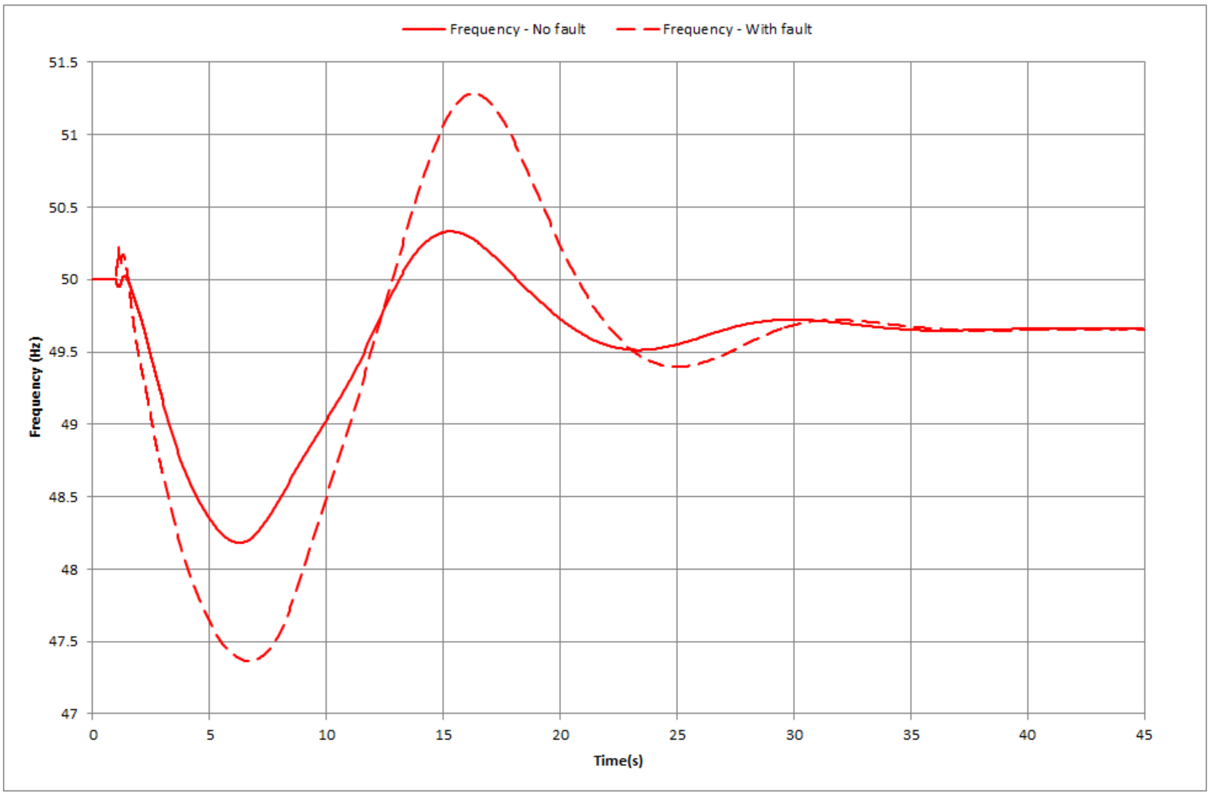

Fig. 2-14 Comparison if system frequency when a generator is lost with and without a fault

2.4 Conclusion

A wind farm usually has a very different response to system disturbances to a synchronous plant. Some of this response is due to the different physical differences between synchronous plant and wind farms, other parts are due to the active control of the converters in the wind turbines.

From the point of view of the grid the primary differences can be summarised as:

- Fault current contribution is 3 to 5 times lower than synchronous machines resulting in more depressed voltages in the network during faults;
- Active power recovery after a fault is much slower resulting in a significant energy deficit after a fault;
- The discontinuous switch between 'fault ride through' and normal mode results in grid transients when modes switch;
- The lack of inherent inertial response to changes in frequency causes a higher rate of change of frequency after generator or load faults; and
- While technically capable most wind farms have no governing action, further exacerbating frequency disturbances.

The effect these response differences have on the case study power system will be analysed in the next chapter.

Chapter 3 Impact of wind on a small power system

The main focus of this thesis is to determine the impacts of additional wind on a small power system. As discussed in Chapter 1 Tasmania is used as a case study. This chapter discusses the issues observed in the course of the study. Possible methods of mitigating these issues are discussed in 3.4.

3.1 Assumptions and modelling

This study has been performed using Power System Simulator for Engineers (PSS/E) version 29.5. Wind plant is modelled as per Appendix A.

The rest of the Tasmanian power system is as per the current validated models. The Tasmanian power system is described in more detail in Appendix B.

There were two wind farms modelled in addition to the existing two. These four wind farms are shown in Fig. 3-1.

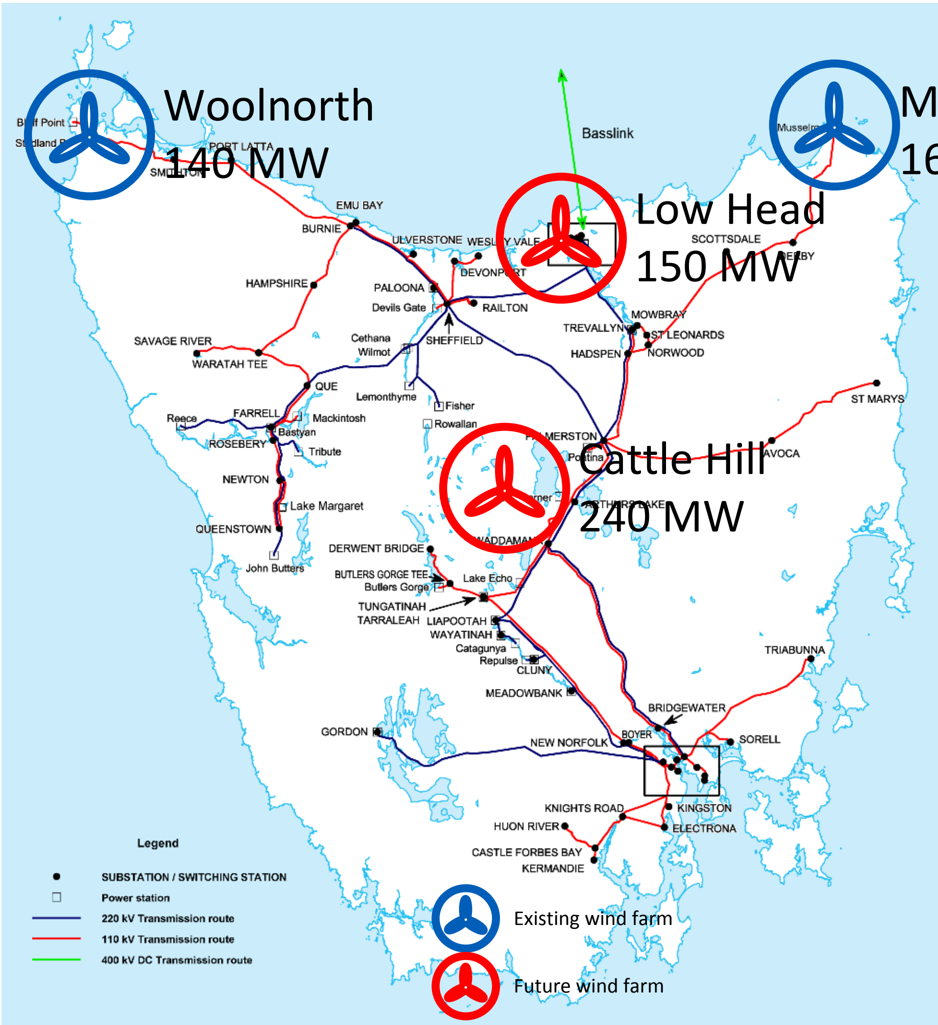

Fig. 3-1 Modelled wind farm locations and sizes [45]

Since this study was initiated Musselroe wind farm has been constructed and is now generating. This has led to some of the issues described in this thesis appearing in the Tasmanian system.

The system was dispatched according to current system constraints and frequency control requirements.

Where a system did not ride through successfully the system inertia was increased, generally by bringing hydro generators online in synchronous condenser mode, until the system did successfully ride through.

3.2 Assessment criteria

A system response was assessed as inadequate if:

- There was Under Frequency Load Shedding (UFLS) action.
- There was system separation.
- Frequency exceeded the bands allowed.
- Rate of Change of Frequency exceeded 4 Hz/sec.
- A control system was unstable in some other way (such as Fault Ride Through (FRT) restrikes).

A listing of all cases and their observed issues is shown in Appendix C.

3.3 Issues

The main issue observed in this study was the system impact of fault ride through controls on wind turbines.

A wind farm has two distinct modes of operation: normal (non-faulted) and fault ride through. Fault ride through mode is activated generally when the terminal voltage of the wind turbine drops below a particular value.

The operation of fault ride through mode itself is not necessarily a problem; the main problem is what the wind farm does after fault ride through mode.

Because of the weak electrical system in Tasmania wind plants have had to slow their recovery from fault ride through mode to normal generation mode. This response is to prevent voltage collapse at their terminals. This method however can introduce issues of its own. Individually the wind farm's response is not big enough to cause system issues, but when many wind farms have the same response simultaneously issues begin to arise.

In larger electrical systems a fault in one part of the grid will only affect the immediate area. Remote parts of the grid will generally not see the full extent of the voltage dip. The Tasmanian electrical system, being relatively small, does not have this effect. A fault centrally in the network will cause a low voltage everywhere. This is shown in Fig. 3-2.

Fig. 3-2 Voltage effect of a fault in the Tasmanian electrical system [45]

Existing wind farms in Tasmania have a threshold for fault ride through of 0.85pu. This means that all wind farms in Tasmania will enter fault ride through mode simultaneously for the fault shown in Fig. 3-2.

The most central part electrically of Tasmania’s network is George Town. This substation also connects Tasmania’s only interconnector to Victoria and Tasmania’s largest single generator. The interconnector is a line-commutated HVDC connector. This means that the worst electrical fault can also be coupled with the loss of the largest generator.

The effect this has on the system frequency can be readily studied by overlaying the system response to loss of the largest generator both with and without an initiating fault. This is shown in Fig. 3-3.

Clearly the frequency response with a fault is much worse. In this case it causes under frequency load shedding due to its severity. There is no load shedding without the fault.

Much of this response can be traced to the fault ride through response of the wind farms. This response is shown in Fig. 3-4.

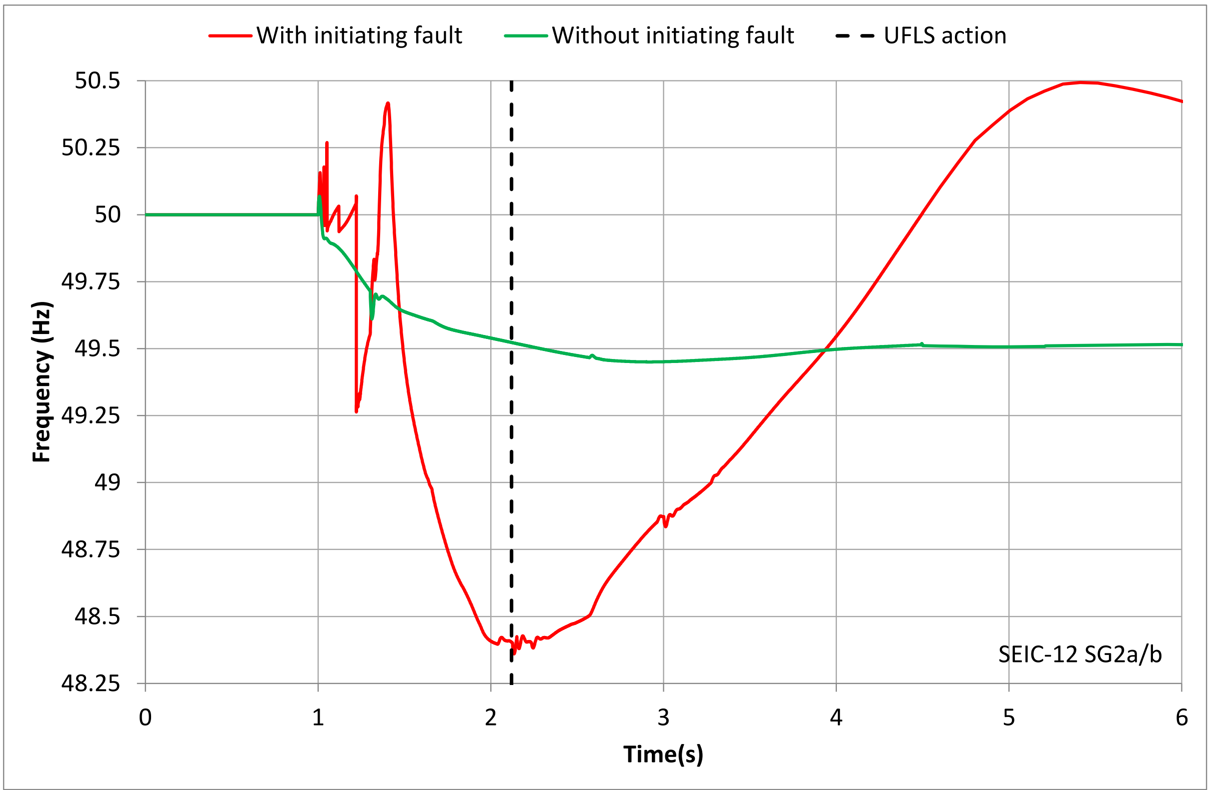

Fig. 3-3 Comparison of frequency response to loss of a large generator with and without a fault

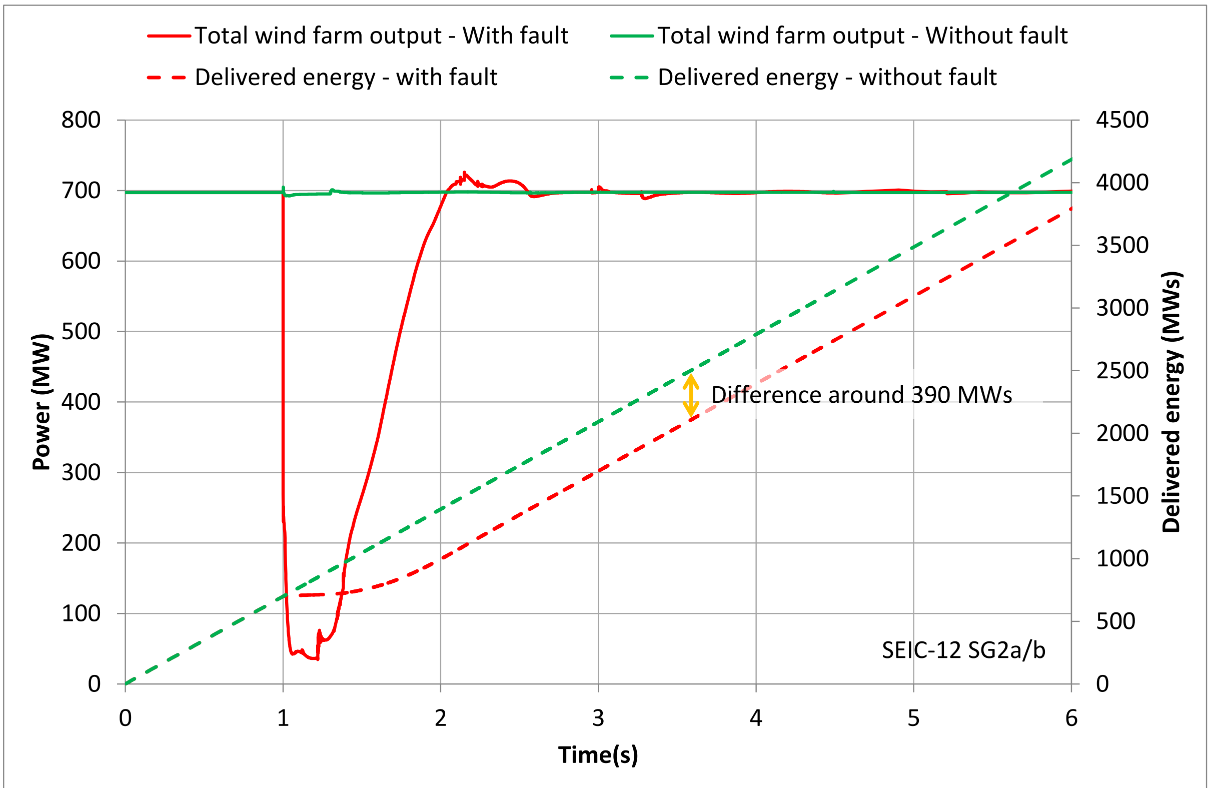

Fig. 3-4 Wind farm fault ride through response energy comparison

There is approximately a 390 MW deficit in generated energy from the wind farms cumulatively due to their fault ride through action. This is around 11.5% of the total system inertia after the disturbance. Simplistically the frequency of a rotating body (such as a machine's rotor) is related to the square root of the energy stored in it, as shown in (3.1).

$$\omega \propto \sqrt{E} \tag{3.1}$$

If 11.5% of the energy stored in the body is lost, 5.9% of the speed is lost. In a 50 Hz system this would result in a theoretical frequency drop *purely from the wind farm's active power loss* of 2.95 Hz. This alone is sufficient to breach the frequency standards for Tasmania which do not allow the frequency to drop below 48 Hz for this sort of event.

The wind farm's reduction in active power output tends to occur at the time when its impacts are worst. Tasmanian generation is primarily hydroelectric. These machines have a lower ability to increase their output quickly because they need to accelerate the column of water in their penstocks. The mechanical (shaft) power output from all of Tasmania's generators (aggregate) to this disturbance is shown in Fig. 3-5.

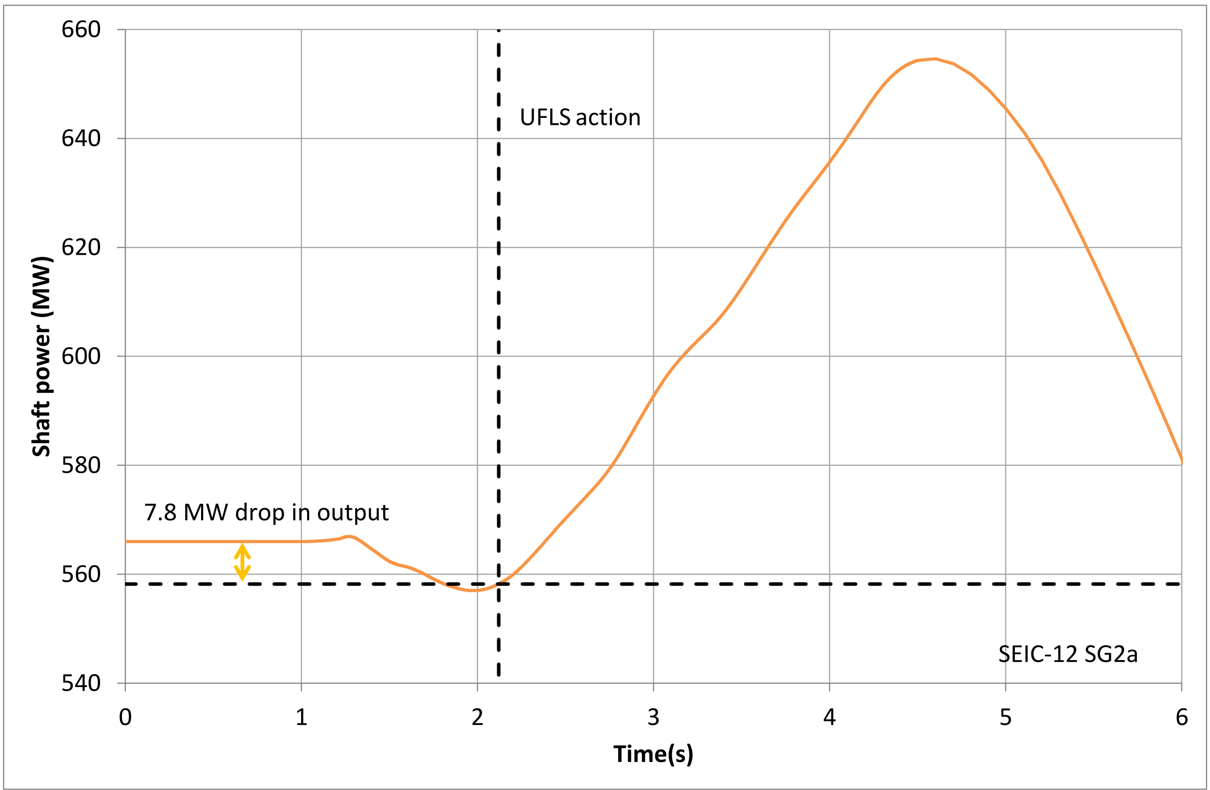

Fig. 3-5 Tasmanian hydro electric generator response to frequency disturbance

The HVDC interconnection to Victoria has a fast frequency controller installed. This, to most disturbances, is the fastest frequency controller in Tasmania. Being a line commutated link means that it cannot operate when the line voltage is too low. This is especially true when the Tasmanian terminal is acting as an inverter (power flow towards Tasmania). This is shown in Fig. 3-6.

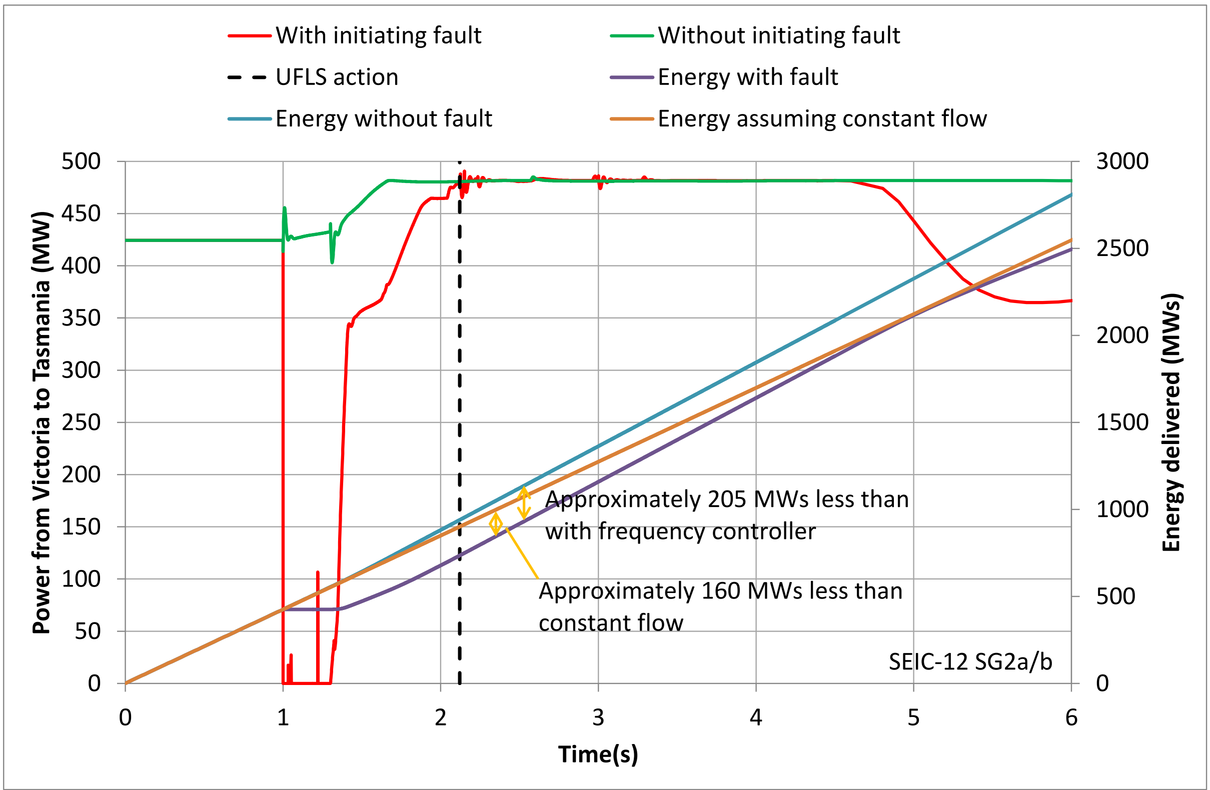

Fig. 3-6 HVDC response to frequency disturbance

The power has recovered by the time the under frequency load shedding action happens, but there is still a net deficit of power of 160 MW compared with the case where flow remains constant.

Knowing the flow on the interconnector and the wind generation, the relative energy loss from the two can be calculated using (3.2). This can be used as a simple 'rule of thumb' to compare the energy loss from the two sources.

$$Energy\ Loss\ Ratio = \frac{Energy\ Loss}{Initial\ output} \tag{3.2}$$

For the HVDC this is 0.38 and for the wind plant this is 0.57. This implies that each megawatt of wind generation contributes around 1.5 times the energy loss after a fault compared with the HVDC interconnector. This is compounded by the fact that the HVDC interconnector attempts to control the frequency when it is not blocked.

The under frequency load shedding is an emergency control scheme intended to prevent the system blacking out after a major failure. It is not intended to operate for normal (credible) contingencies such as loss of a generator. The system in Tasmania is divided into several blocks, each with different characteristics. Details of these blocks are shown in Table 3-1.

Table 3-1: Under frequency load shedding blocks and triggers

Block	Trigger	Time
1	49 Hz AND >1.176 Hz/s 47.96 Hz	Instant Instant
2	48.8 Hz AND >1.176 Hz/s 47.84 Hz	Instant Instant
3	47.75 Hz	Instant
4	47.57 Hz	Instant
5	47.39 Hz 47.57 Hz	Instant 10s
6	47.29 Hz 47.39 Hz	Instant 10s
7	47.19 Hz 47.29 Hz	Instant 10s
8	47.09 Hz 47.19 Hz	Instant 10s

Generally the rate of change of frequency triggered blocks 1 and 2 will trip due to the fault ride through characteristic of the wind farms. The rate of change of frequency triggers on these blocks is designed to arrest system frequency decline to large disturbances such as loss of the HVDC connector when the special protection scheme has failed.

In the studies performed for this thesis this issue was the most significant. In most cases it would occur before any other issue and when it was mitigated other issues would also be mitigated. Mitigation of this issue is discussed further in 3.4.

The location of the most significant generation event becomes important with additional wind generation. Currently frequency control services are not dispatched with this consideration.

Tasmania is part of the National Electricity Market (NEM). In the NEM frequency control services are procured through a competitive market in several bands:

- Fast services from 0 to 6 seconds after an event
- Slow services from 6 to 60 seconds after an event
- Delayed services from 60 seconds to 5 minutes after an event

This thesis focusses mostly on raise services that attempt to raise frequency after an event that causes reduced frequency.

In most of the rest of the NEM frequency control requirements are constant – they do not vary with system conditions. In Tasmania requirements vary with system inertia. The fast raise FCAS requirements with varying system inertia are shown in Fig. 3-7.

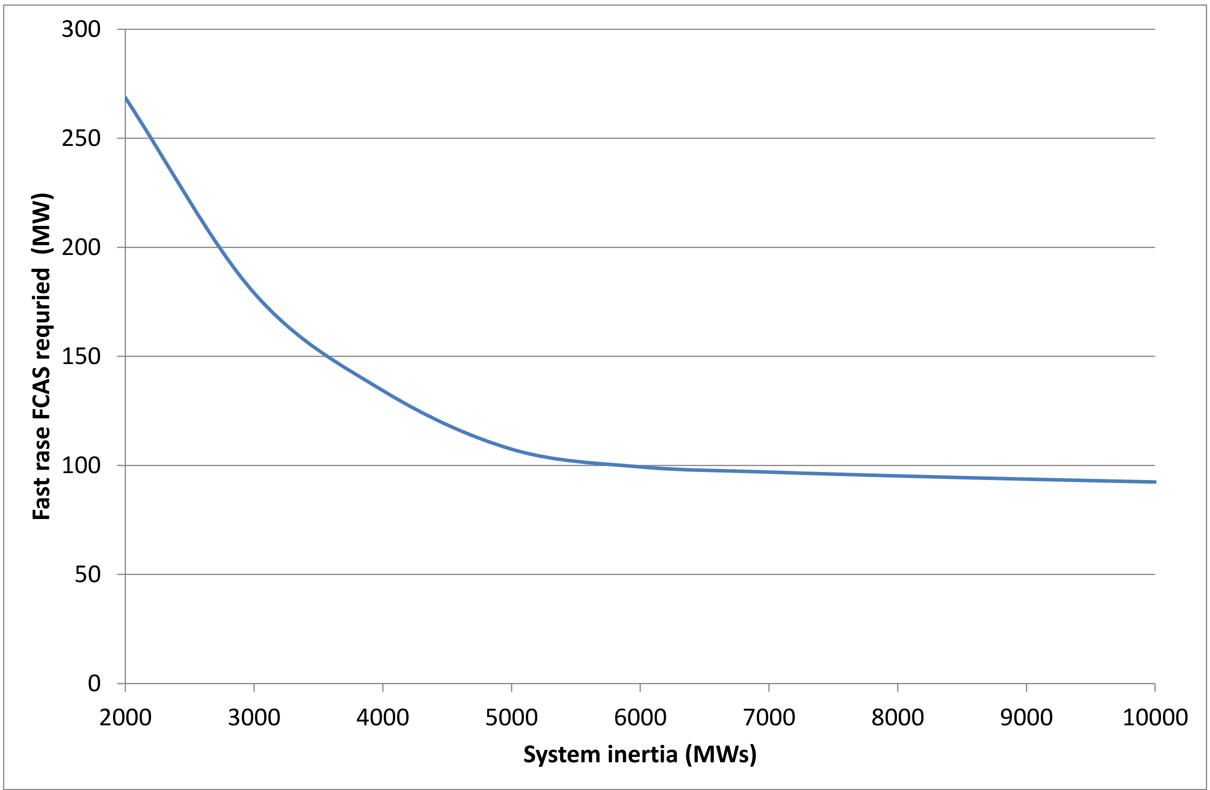

Fig. 3-7 Fast Raise FCAS requirements with varying system inertia

As discussed in Chapter 2 the wind farm fault ride through response can have a significant impact on the frequency of a system after an event.

Generally the current algorithm for determining FCAS requirements will result in higher output generators requiring more inertia than lower output generators, regardless of their location or technology. For pure frequency disturbances this is generally correct. A comparison of loss of Musselroe (168 MW) and the combined cycle gas generator (208 MW) with special protection scheme is shown in Fig. 3-8.

In this case the loss of Musselroe requires 119 MW of fast raise and loss of the CCGT requires 98 MW of fast raise. This case has sufficient frequency control services dispatched as there is no under frequency load shedding action for either contingency.

As expected the larger absolute loss of generation causes a greater frequency dip. When there is a fault however the response is different. This is shown in Fig. 3-9

In this case, the CCGT is located centrally in the network and causes all wind farms to enter fault ride through. The wind farm, however, is located remotely and does not have the same effect. This is shown in Fig. 3-10.

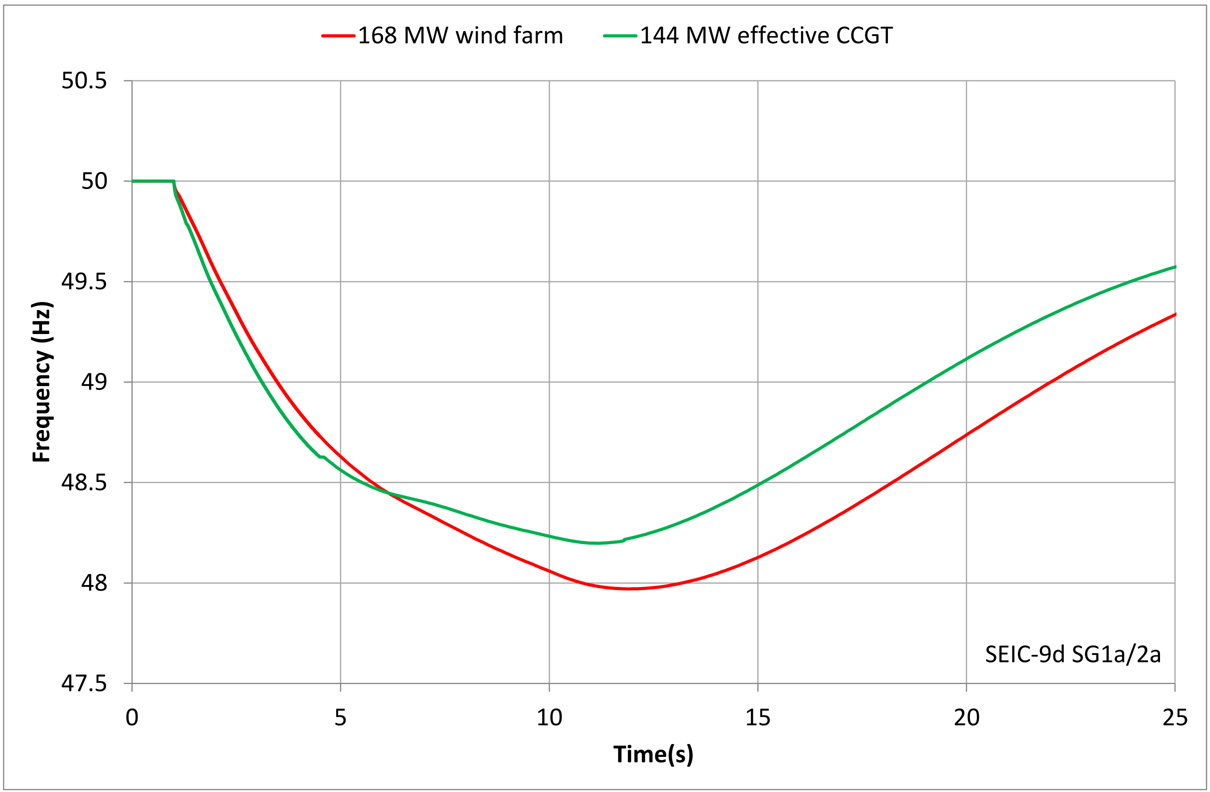

Fig. 3-8 Frequency response to loss of varying size generators with no fault

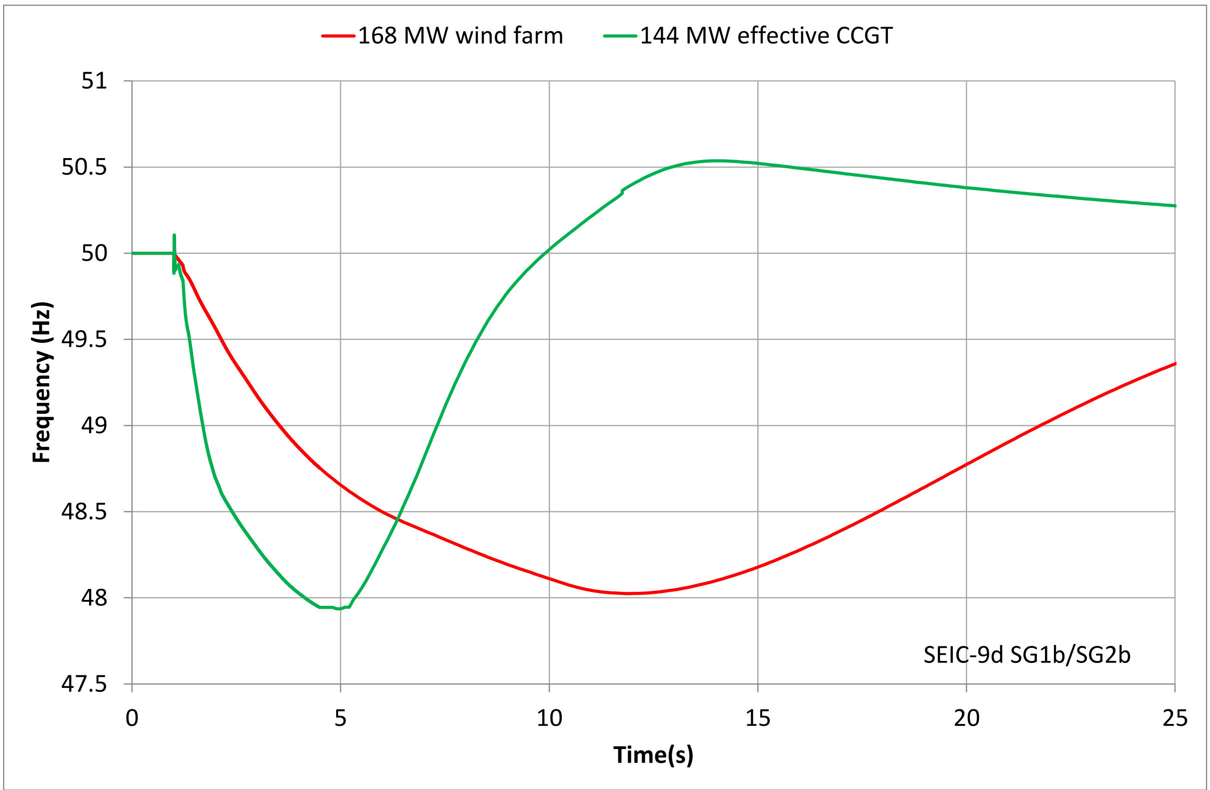

Fig. 3-9 Frequency response to loss of varying size generators with fault

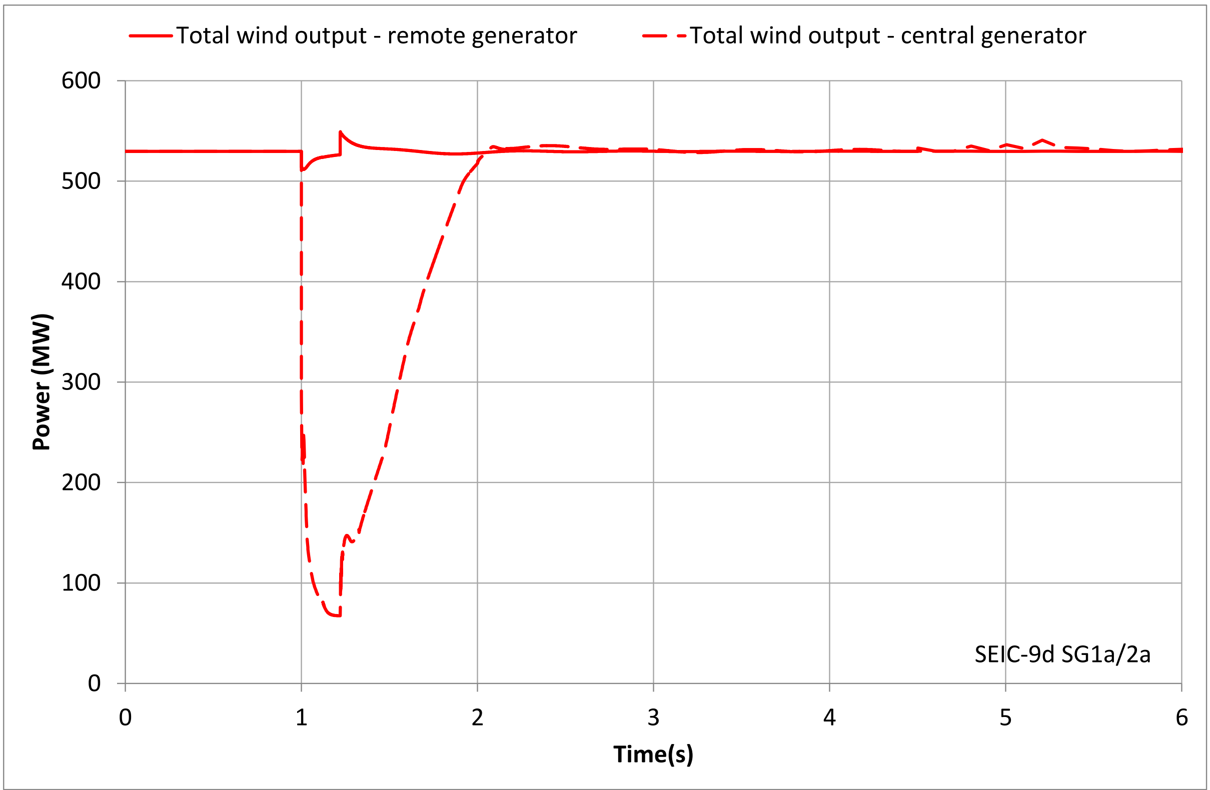

Fig. 3-10 Wind farm cumulative output for central and distant faults

The energy balance effects of wind farm fault ride through must be taken into account in the frequency control services calculations to maintain system security. This is in section 3.4.

Generally a wind farm is unable to ride through the same levels of disturbance that a synchronous plant can. This is compounded by the slow voltage control and lack of reactive power capability. A particular example in Tasmania is caused by a DC fault on the HVDC interconnector. This line-commutated interconnector has switched capacitors to mitigate its reactive draw and provide harmonic filtering. When a fault occurs on the DC side of the converter the reactive draw drops and the reactive power provided by the capacitors is instead directed into the electrical network. The voltage then rises. This effect is shown in Fig. 3-11.

After this fault the wind farm voltage control is slow to act to reduce the overvoltage. Often it makes the voltage worse. The reactive power from one wind farm is shown in Fig. 3-12.

Had the wind farm reduced its reactive output quicker it would have avoided tripping.

Increasing wind penetration can also cause previously stable control schemes to become unstable. This was particularly true for the HVDC interconnector.

When the HVDC link's control scheme was designed it was assumed that the strength of the rest of the Tasmanian system would exist between certain boundaries. As more wind generation connects, the system is more likely to exceed these boundaries.

The harmonic filtering and voltage control systems are particularly affected. The increasing wind penetration can make voltage and harmonic filtering requirements conflict. This is shown in Fig. 3-13.

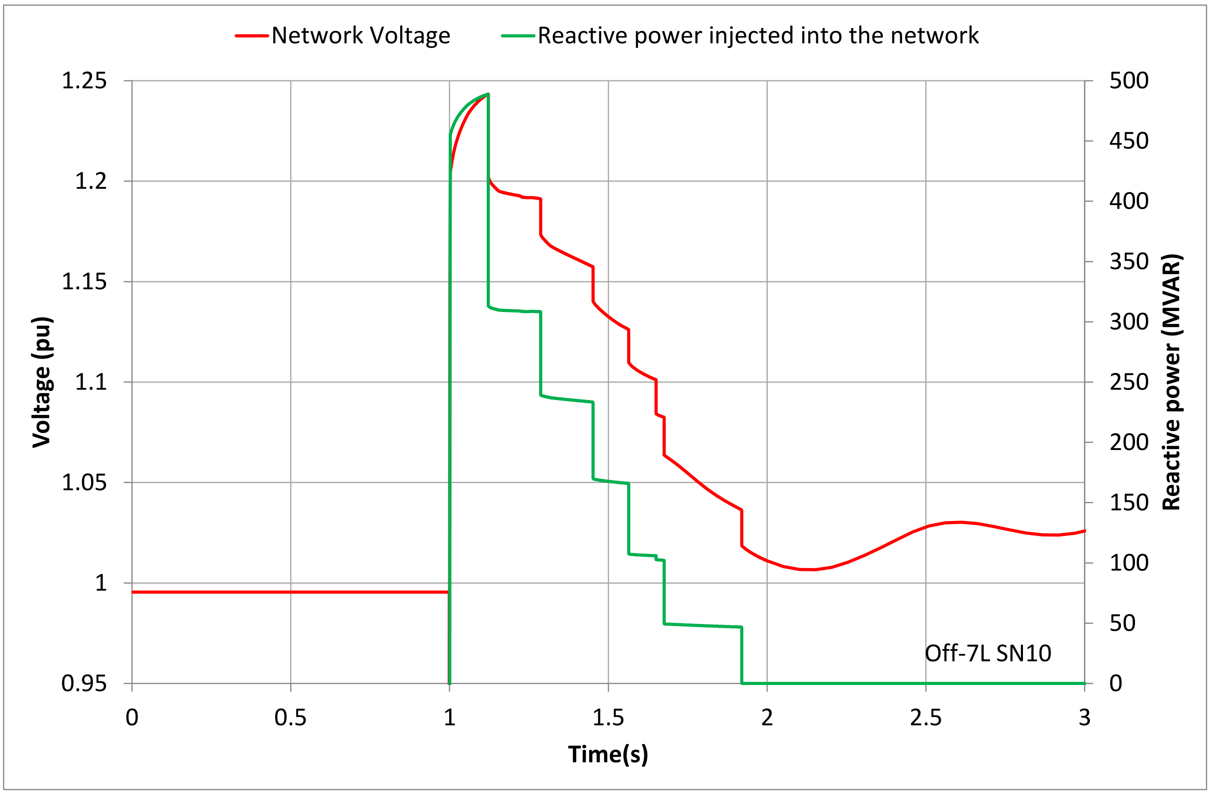

Fig. 3-11 Reactive power and voltage after a DC fault

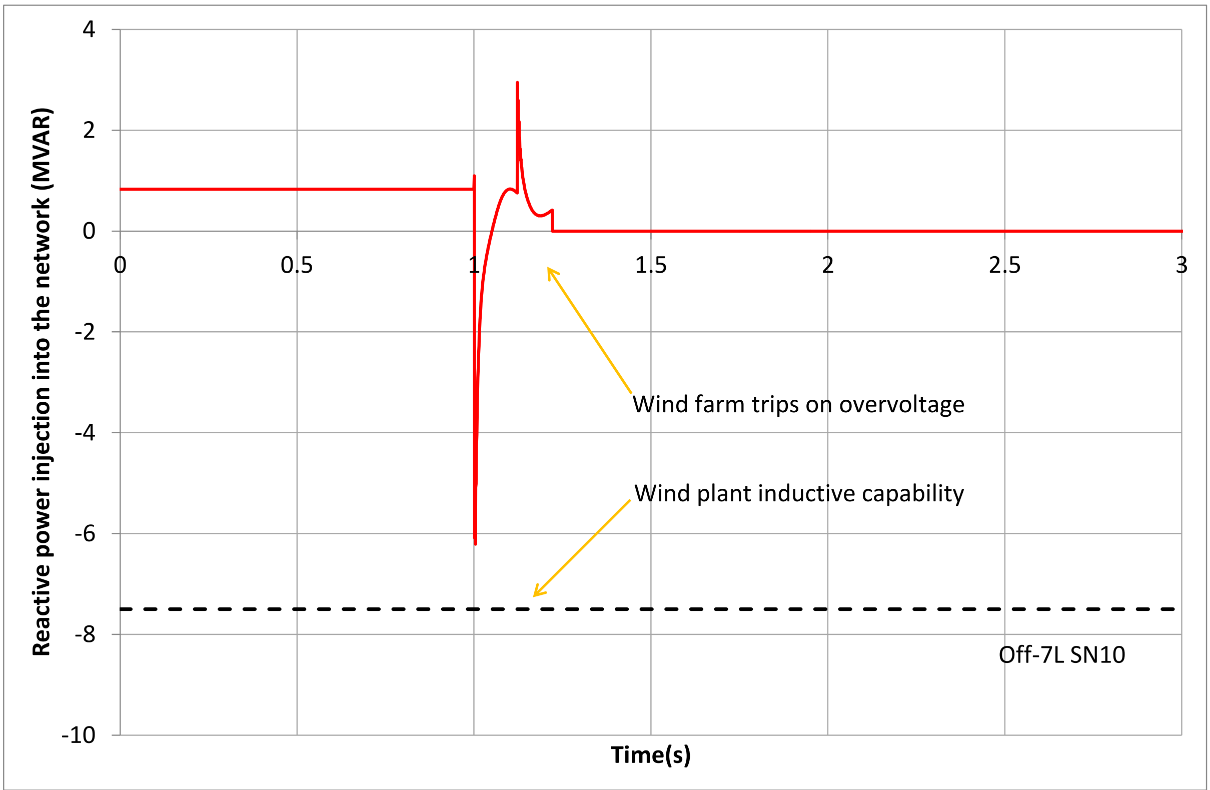

Fig. 3-12 Wind farm reactive response to overvoltage

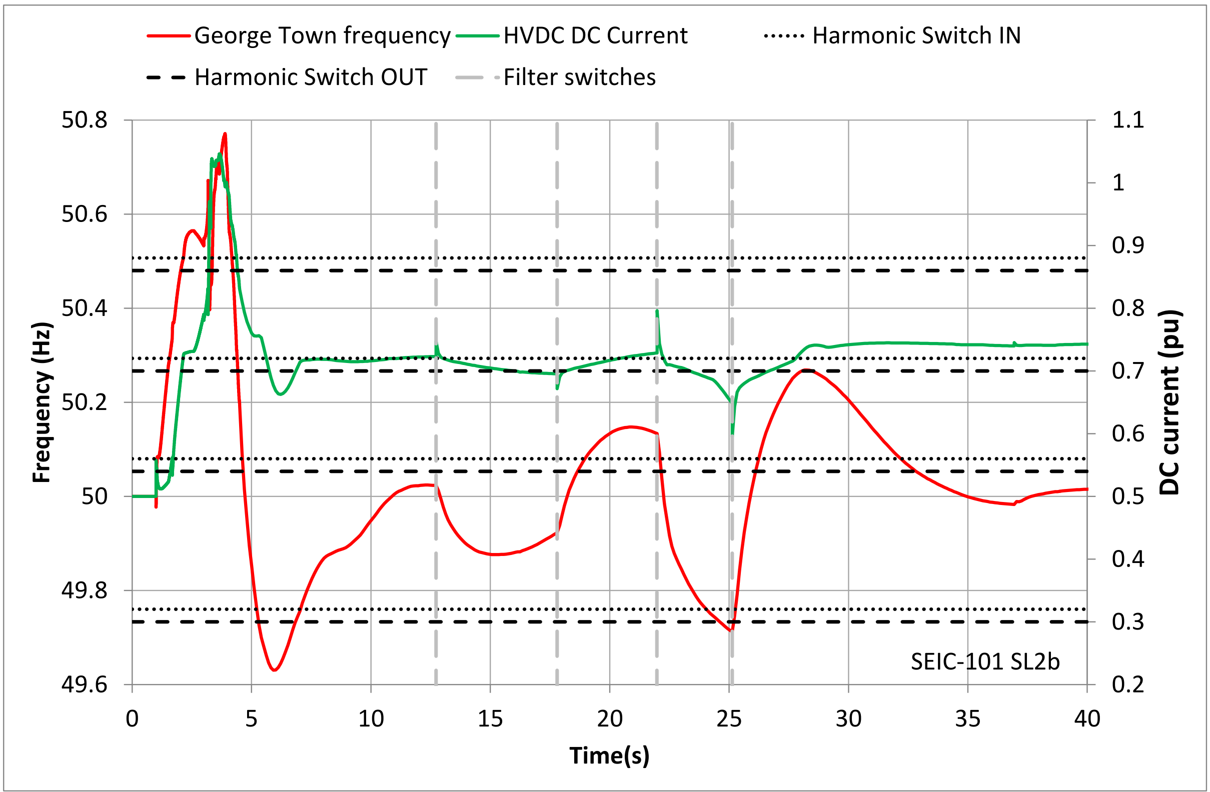

Fig. 3-13 HVDC filter instability

With only a few synchronous generators in service the voltage control is poor and each switch of the HVDC filter bank causes a significant change in voltage. The change in voltage triggers a change in load due to its voltage dependence. This change in load triggers a change in frequency. The change in frequency causes HVDC flow to reduce (as the interconnector is exporting from Tasmania in this instance) and the filter is no longer required. The filter switches out and through the same process this causes a flow increase and the filter to switch back in. As the filters require some time to discharge after they have been in service there are eventually no filters left to switch.

The line commutated HVDC link can experience issues on import to Tasmania. This issue is caused by commutation failure. Commutation failure occurs when the thyristors in the HVDC link fail to turn off. This is often caused by a weak system. This issue exists without additional wind generation particularly when the frequency controller causes HVDC flow to increase on import after loss of a generator. Wind generation makes this event much more likely however.

The HVDC interconnector is a very large monopole link for Tasmania. It is thus equipped with a special protection scheme to control frequency if it is lost in a contingency [46]. If energy is being exported from Tasmania this scheme will trip excess generation. Only certain generators are part of this scheme and all are synchronous machines. With large amounts of wind generation this can result in most of the synchronous machines in Tasmania tripped to control frequency. An example of this happening is shown in Fig. 3-14. In this case there is 930 MW of Tasmanian load, 250 MW of HVDC export from Tasmania, and 700 MW of wind generation. Before the disturbance occurs there is 480 MW of synchronous generation in Tasmania. 250 MW of this is lost with the HVDC fault leaving only 230 MW running.

The loss of the HVDC connector on export from Tasmania would generally cause the frequency to increase however in this case the frequency has dropped, causing under frequency load shedding. This causes a high system voltage and wind farms to trip. The high system voltage also causes instability in a synchronous machine.

If the special protection scheme trips wind farms instead of synchronous machines the response is much more acceptable. This is shown in Fig. 3-15.

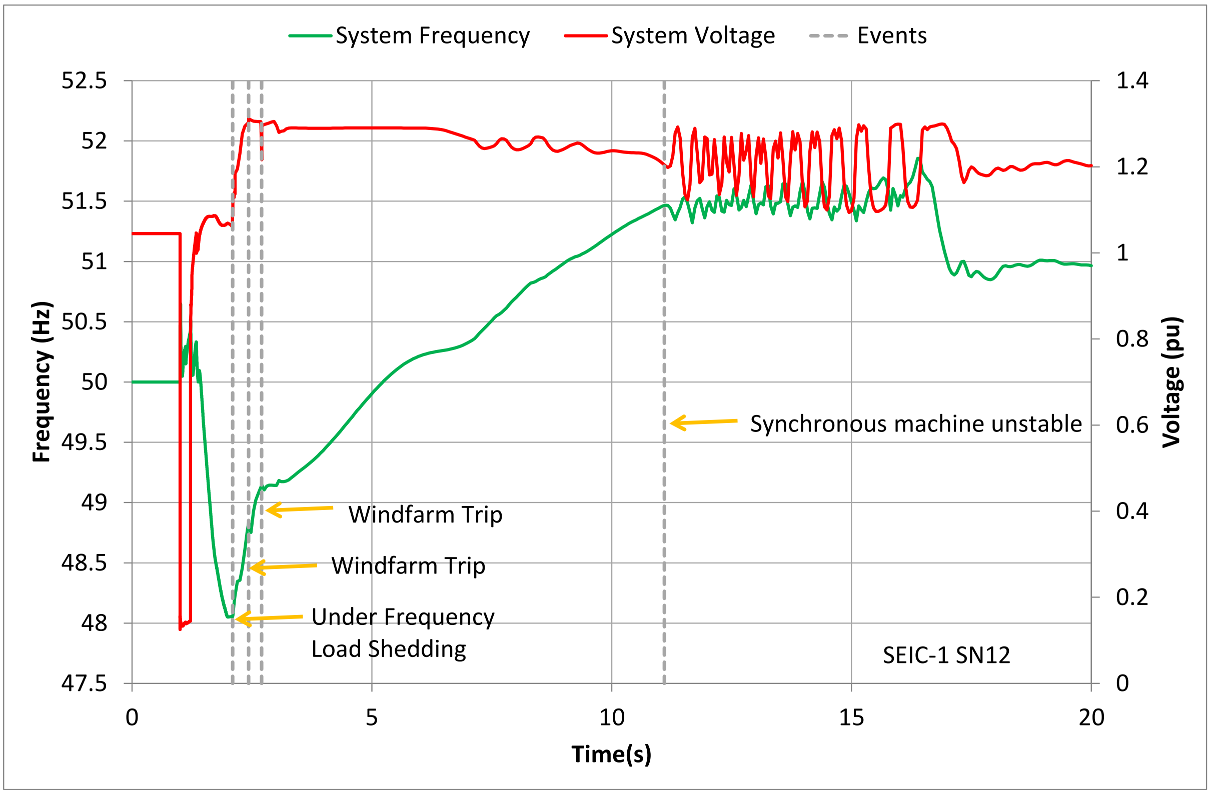

Fig. 3-14 Special Protection Scheme action causing instability

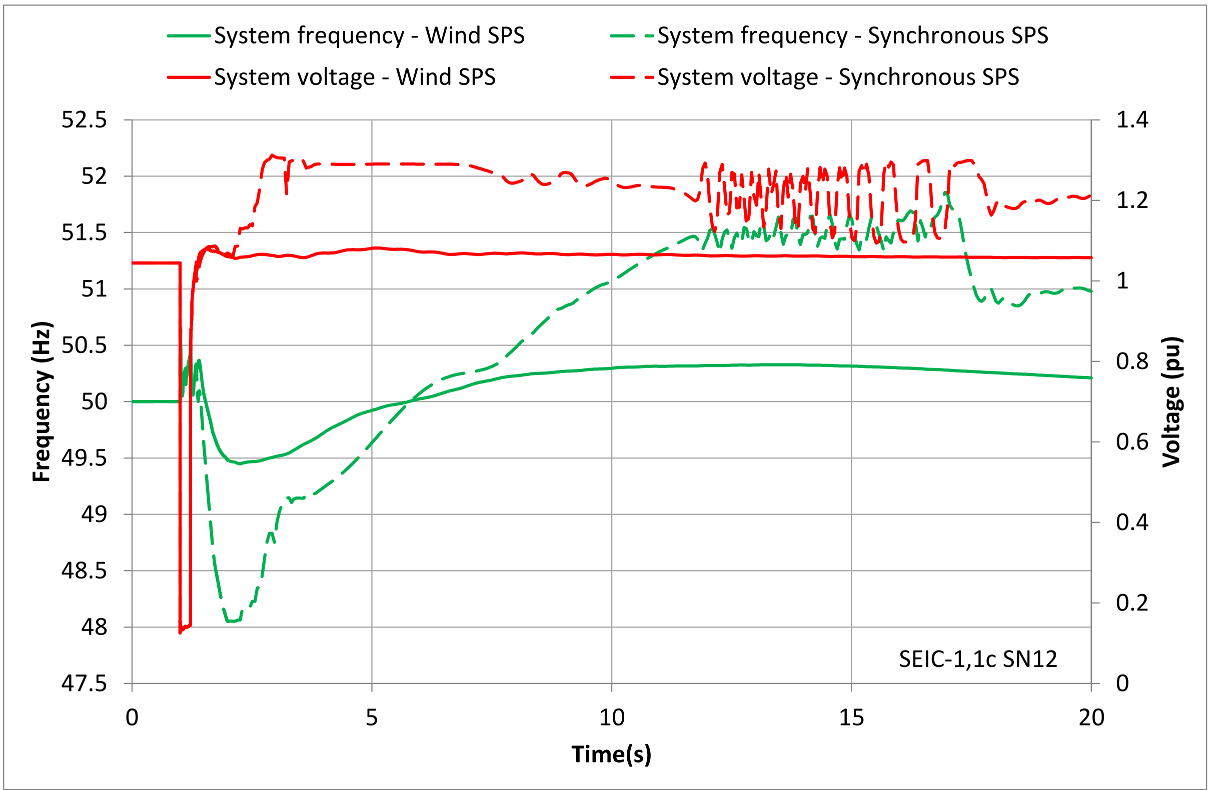

Fig. 3-15 Comparison of wind and synchronous SPS

3.4 Mitigation of system issues

The issues observed above all pose a threat to the power system if left unresolved. In this chapter possible mitigation methods are discussed and their impacts analysed.

Some of the mitigations suggested require wind plant to have additional capabilities, while others can be implement operationally or require investment on the system side. The economics of the issues and their proposed solutions are not considered in this thesis.

3.4.1 Wind integration metric

As an initial method of ensuring system security a simple metric could be used. This could be used to perform some action if a calculated value exceeds a threshold.

As discussed in 1.2.4 Ireland has adopted a simple wind integration metric to analyse in real time whether the power system is secure. This metric is shown in (3.3) [33].

$$SNSP = \frac{Wind + Imp_{HVDC}}{Load + Exp_{HVDC}} \tag{3.3}$$

Where:

Wind is the instantaneous total output of all wind generators in the system.

Load is the instantaneous demand on the system.

Imp_{HVDC} is the total energy import through HVDC interconnectors.

Exp_{HVDC} is the total energy export through HVDC interconnectors.

A similar metric could be adopted in Tasmania to ensure system security. Any simple metric will sometimes prevent system conditions that would otherwise be stable from occurring. This will cause some additional market cost as more expensive generation is dispatched to meet the constraint. A simple metric would however prevent most unstable system conditions from occurring and thus maintain system security.

As a first test the SNSP metric can be simply applied to the Tasmanian system to see how representative it is. Historical data (including existing wind generation) in Fig. 3-16 shows the SNSP ratio in 2012 and 2013 peaked at 63% and was over 50% 2.2% of the time.

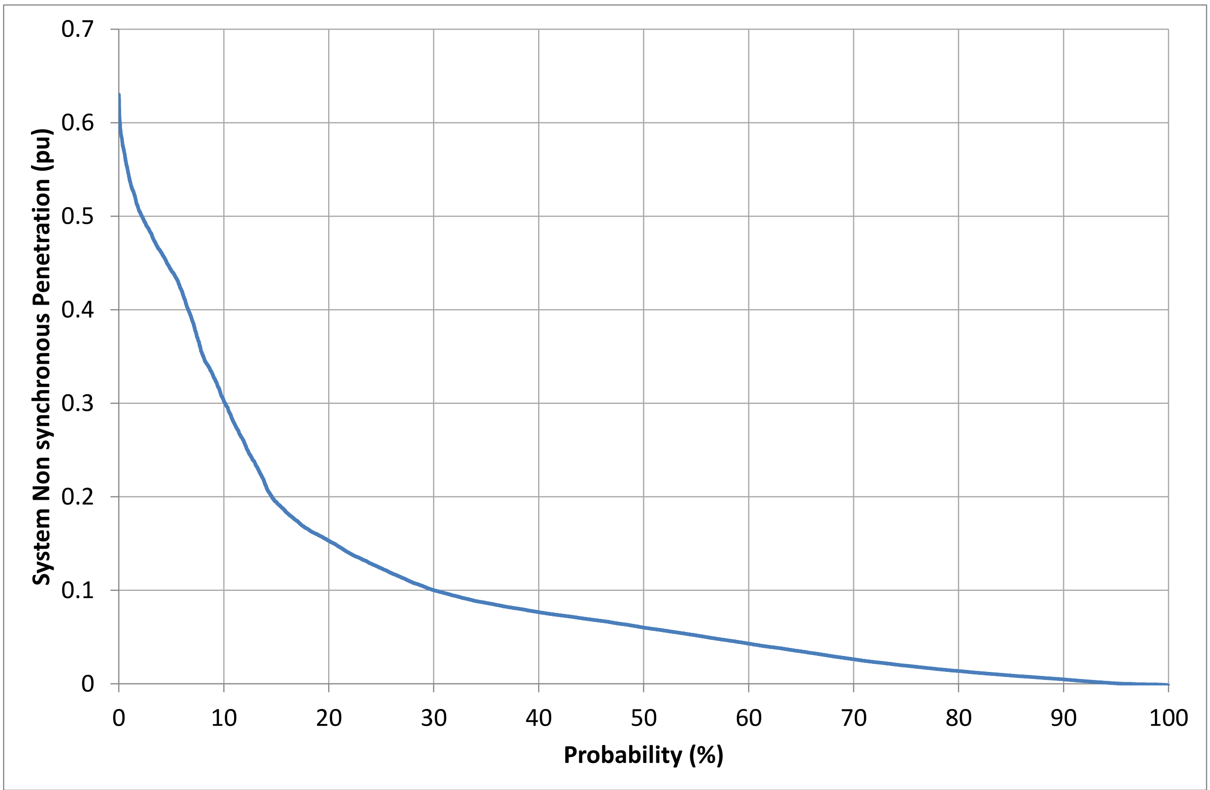

Fig. 3-16 SNSP in 2012 and 2013 in Tasmania

The Irish experience indicates that an SNSP of around 50% can be tolerated without system issues and up to 75% with some changes to protection settings. This indicates that according to the SNSP metric Tasmania is already within the danger zone for non-synchronous penetration.

The main issue with the SNSP is that it is not necessarily a good indicator of system instability in Tasmania. In this study cases between 7.3% and 92.8% SNSP were considered. Generally cases at any SNSP were able to pass without failure and cases as low as 38.5% SNSP failed. This is shown in Fig. 3-17.

The main reason for this is the different generation mix in Tasmania compared with Ireland. Most Irish generation is thermal with a small amount of pumped hydro. Thermal generation has a much less flexible dispatch compared with Tasmania's hydro generation. Thermal generation has a minimum stable output below which it must shut down. This means that for a given amount of load that is supplied by thermal machines there is a minimum number of thermal machines that can supply it. This can be approximated by (3.4).

$$N_{gen,max} = \frac{P_{gen}}{P_{min}} \tag{3.4}$$

Where:

$N_{gen,max}$ is the maximum number of synchronous machines that can supply a load

P_{gen} is the synchronous generation

P_{min} is the minimum stable generation output

For a thermal machine P_{min} is usually around 40% of the rated output [47]. This limitation exists primarily because if the generation is lower the flame in the boiler becomes unstable and may be extinguished.

Hydroelectric machines have no such limitation. Their energy comes from a moving water column. The power output is adjusted by altering the amount of water that is allowed to flow into the turbine. Rough running zones notwithstanding there is no limit to how little water may be allowed into the turbine. Many hydroelectric machines are also capable of running with no water in the turbines (in synchronous condenser mode). Fig. 36 shows a probability density function for a Tasmanian machine in 2012 and 13

Using machines in synchronous condenser mode it is possible to alter the strength of a system without altering the SNSP. All cases which failed were able to be restored while maintaining the SNSP by adding synchronous condenser units.

Clearly the SNSP is not a good metric to apply to a small power system such as Tasmania.

The main problem observed in this study was rate of change of frequency immediately after a fault. As shown in 3.3 during this time the system essentially relies on its inertia to prevent unwanted load shedding. Possibly there is some inertia below which the system will be unstable. The system inertia in Tasmania varies significantly depending on HVDC interconnector flow and load. The system inertia variance in 2012 and 2013 is shown in Fig. 3-19.

With added wind generation this is expected to decrease as hydro generators are displaced. The system inertia of the study cases showing failed and passed cases is shown in Fig. 3-20.

Cases failed up to 6270 MW and passed down to 2260 MW. The actual system inertia was below 6270 MW 9.4% of the time in 2012 and 2013.

Using a pure threshold on system inertia would constrain the system significantly. As stated in Chapter 3 system inertia is what drives system frequency after a disturbance. Why is system inertia not a good indicator?

The root cause of this mismatch is because system inertia is only part of the issue. A system with an arbitrarily low inertia can run acceptably as long as nothing disturbs it. The size of the disturbance will define the adequacy of the system. The adopted metric must thus take into account the size of the contingency. System inertia alone does not do this.

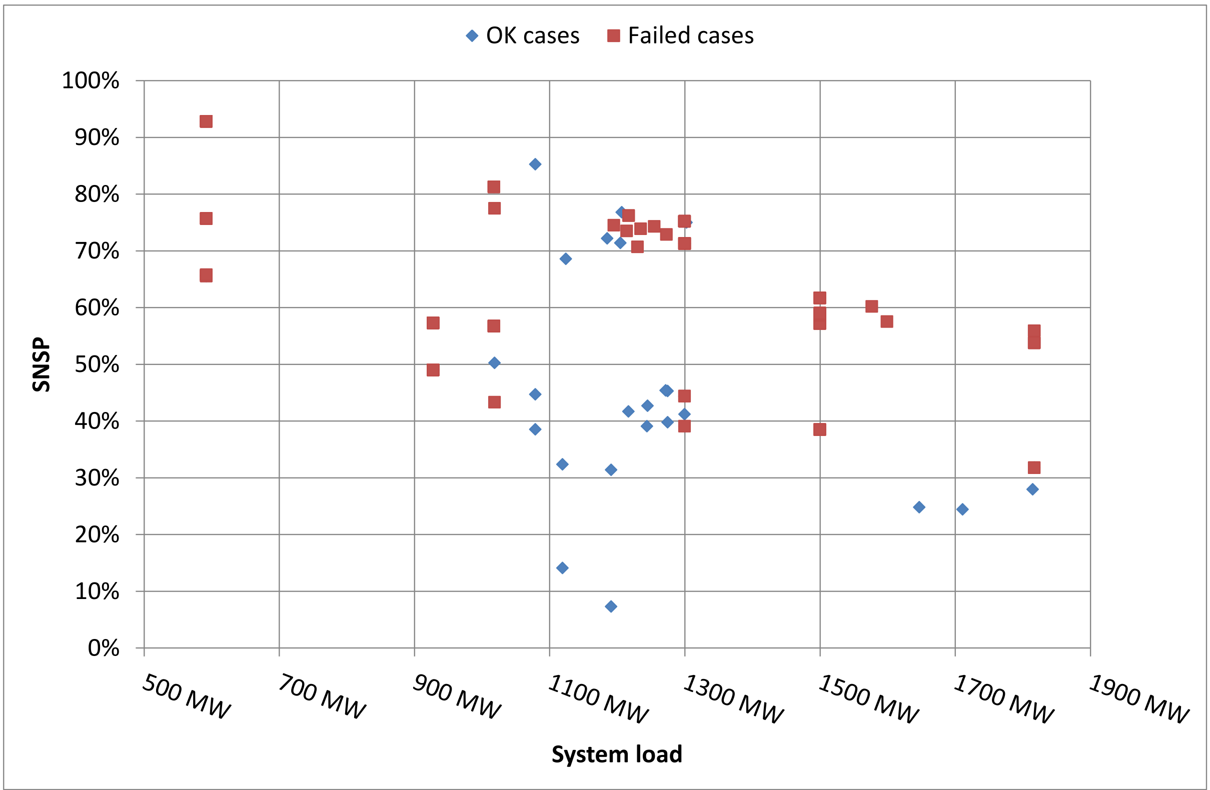

Fig. 3-17 Studied cases SNSP

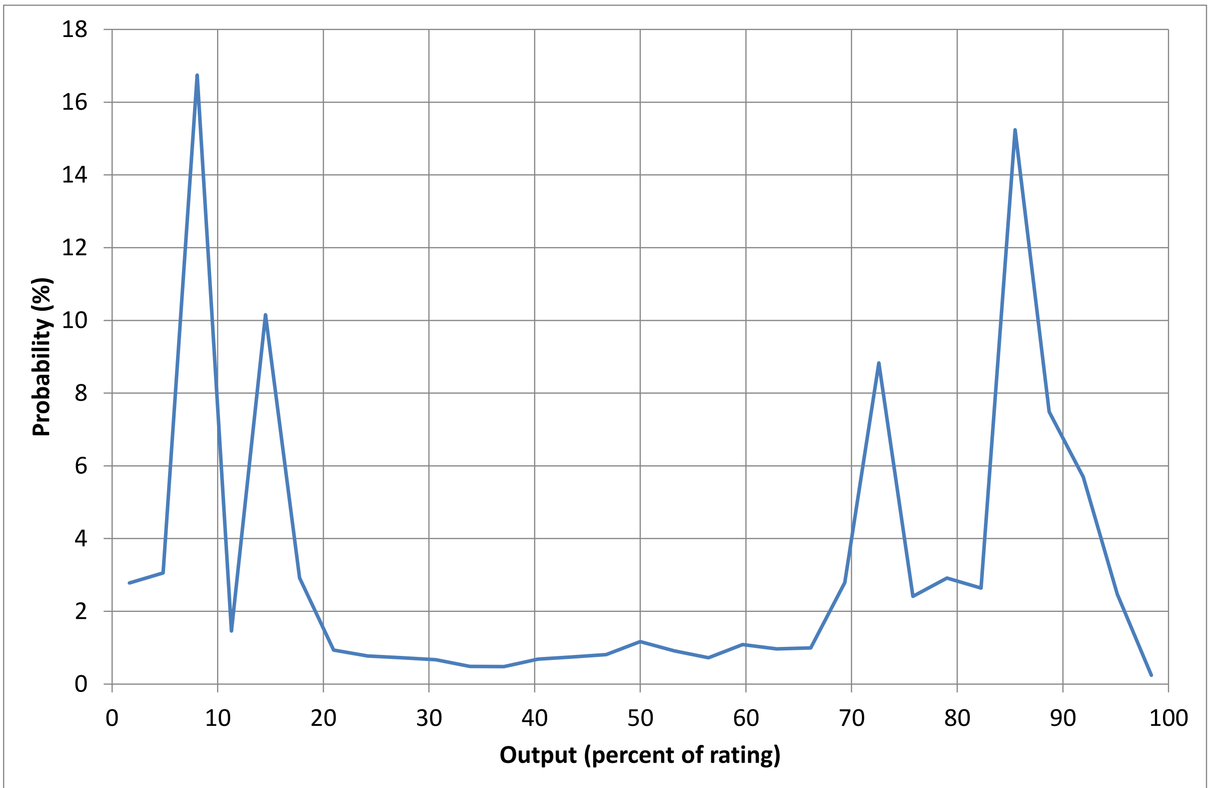

Fig. 3-18 Sample machine output probability density function

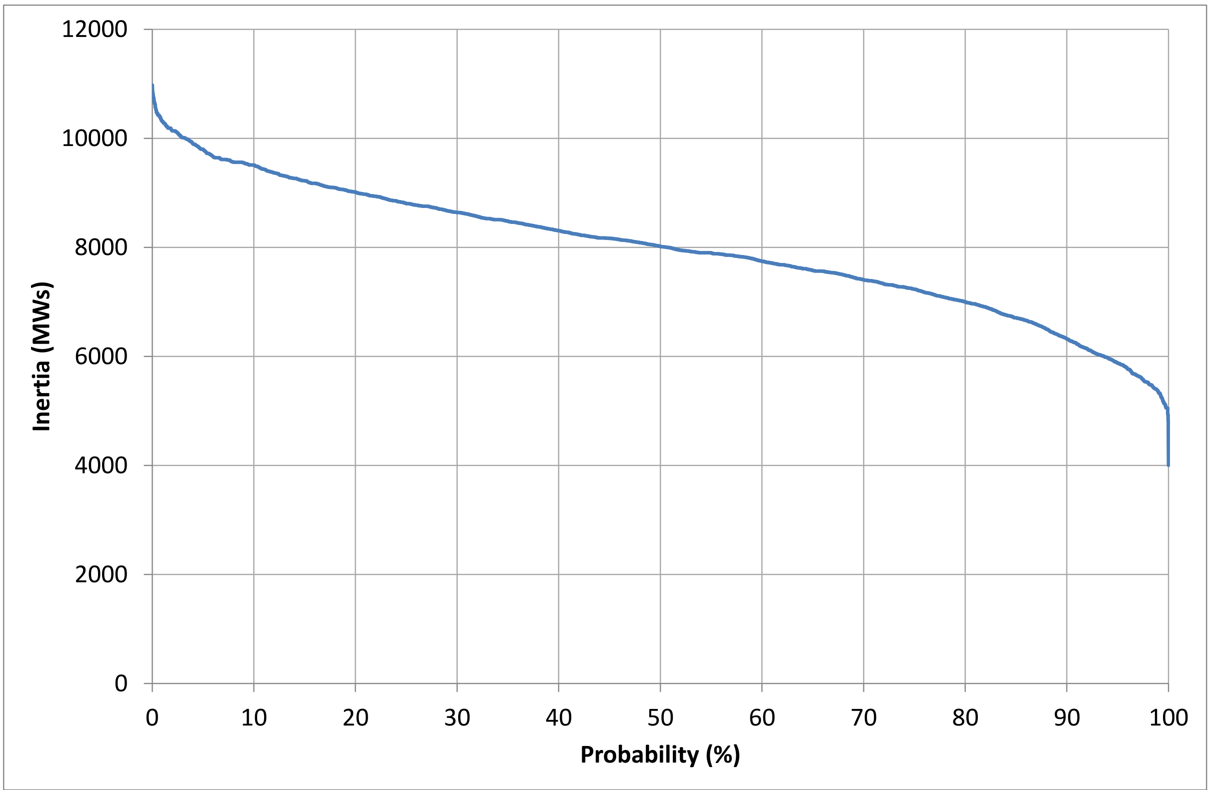

Fig. 3-19 Tasmanian system inertia in 2012 and 2013

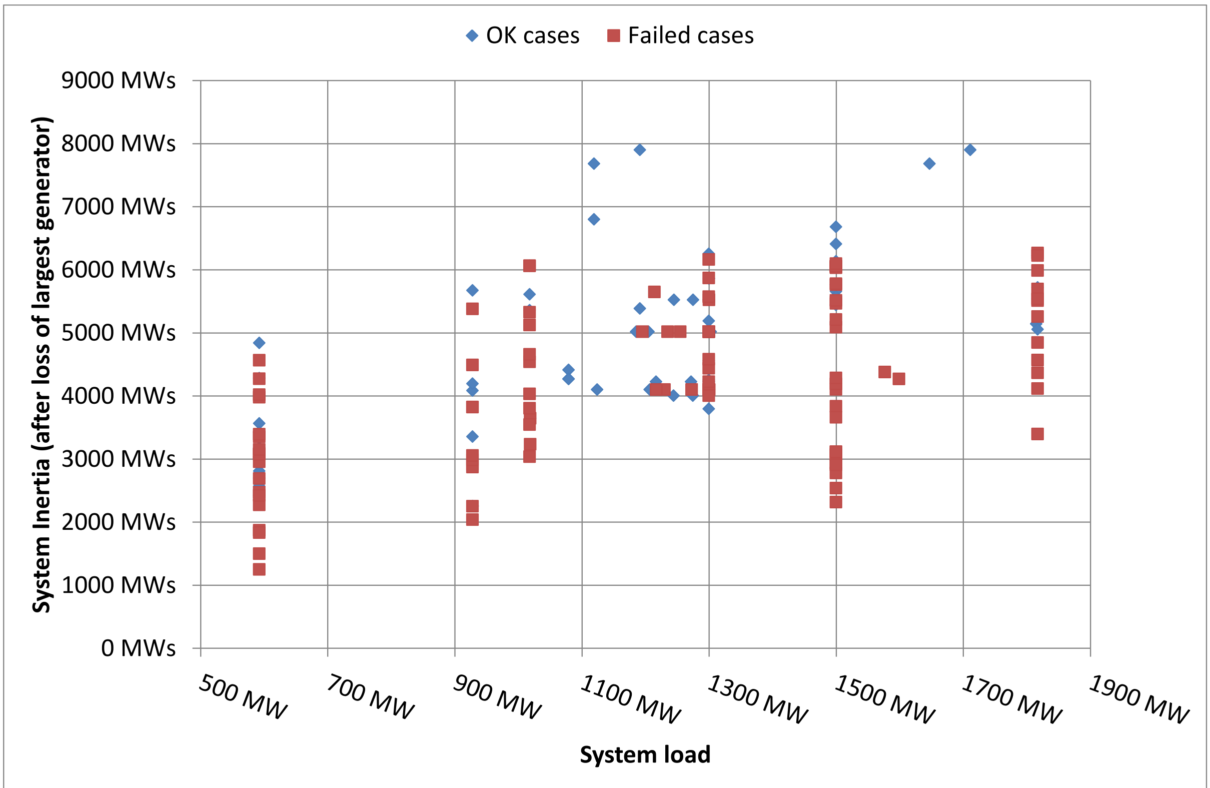

Fig. 3-20 Inertia of studied cases

The third alternative metric does this by considering the inertial response of the system.

Basic electrical theory states that the energy stored in a rotating mass can be described by (3.5) [48].

$$E = \frac{1}{2} J \omega^2 \tag{3.5}$$

where: E is the energy stored in the mass; J is the moment of inertia of the mass; and ω is the rotational speed of the mass.

Before any disturbance occurs the energy input from generators and output to load is exactly balanced. This results in a constant amount of energy stored in the system, given by (3.6) [48].

$$E_o = \frac{1}{2} J {\omega_o}^2 \tag{3.6}$$

where: E_o is the initial energy stored in the rotating mass of the system; and ω_o is the initial rotational speed of the system

When an event occurs (such as the loss of a generator) the energy input and output are no longer balanced. In the case of a generator loss this balance becomes negative. Energy is continuously withdrawn from the system.

The declining energy causes a declining frequency. After a time the remaining energy in the system is as described in (3.7)

$$E_{rem} = E_o - tP_{loss} \tag{3.7}$$

where E_{rem} is the remaining energy; t is the time after the event, and P_{loss} is the power loss through the disturbance.

For this analysis t is 0.78 seconds which is the time between fault clearance (220ms after fault inception) and 1 second after fault inception. There are a range of times that could be used, 0.78s was simply a convenient choice. Rearranging (3.5) the system frequency can be estimated in (3.8).

$$\omega = \sqrt{\frac{2E_{rem}}{J}} \tag{3.8}$$

The system issues arise when the frequency drops too low too quickly. This occurs when there is a high rate of change of frequency. The rate of change of frequency can be estimated simply by comparing the difference in frequency at some time after the event and when the event occurs. This is shown in (3.9).

$$\frac{\partial \omega}{\partial t} = \frac{\omega - \omega_o}{t} \tag{3.9}$$

where $\frac{\partial \omega}{\partial t}$ is the rate of change of frequency.

Traditionally the power loss (P_{loss}) has been simply the initial contingency size however the analysis here has shown that with additional wind this is no longer sufficient. The power loss term must include a factor for wind. This is shown in (3.10).

$$P_{loss} = P_{cont} + P_{wind-loss} \quad (3.10)$$

where P_{cont} is the contingency size; and $P_{wind\text{-}loss}$ is the power loss due to wind farm fault ride through response.

The average power loss due to wind farm fault ride through will depend on the initial power output from the wind generation. This can be modelled simply by multiplying the wind output with a factor as shown in

$$P_{wind-loss} = c_{wind-loss} P_{wind} \quad (3.11)$$

where $c_{wind\text{-}loss}$ is the wind loss factor and P_{wind} is the initial wind farm output.

The wind loss factor $c_{wind\text{-}loss}$ can be determined by averaging the reduction in wind farm power output after the critical contingency. This is shown in Fig. 3-21.

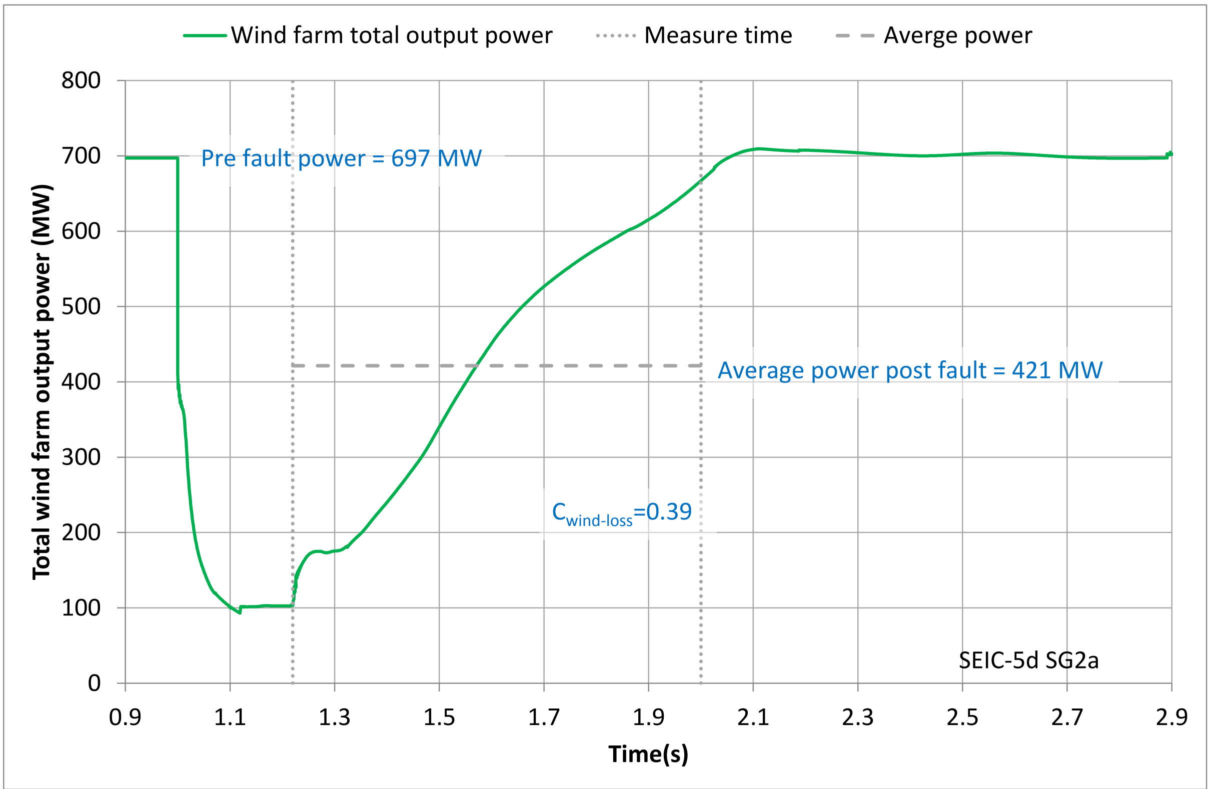

Fig. 3-21 Example $C_{wind\text{-}loss}$

For this particular case 270 MW of wind generation is lost immediately after the disturbance, or around 40%. The actual wind loss factor depends on the case, and is usually around 40-50%. This study has used 45% for all cases.

Each contingency will require a slightly different calculation depending on the characteristics of the fault. There are two primary contingencies considered here: loss of the HVDC interconnector and loss of the Combined Cycle Gas Turbine (CCGT). Primarily the energy balance equation (3.10) is what is altered to reflect the different contingencies.

Loss of the HVDC interconnector is usually only an issue when flow is towards Tasmania, so that is what is considered here.

The power balance equation must be modified to add a new term for its special protection scheme. Due to its size, the HVDC interconnector has a special protection scheme to trip some large loads when it is lost. This is shown in (3.12).

$$P_{loss} = P_{cont} + P_{wind-loss} - P_{sps} \tag{3.12}$$

where P_{sps} is the average load lost as part of the special protection scheme

The SPS load loss can be calculated similarly to the wind loss term, shown in (3.13).

$$P_{sps} = \frac{t - t_{sps}}{t} P_t \tag{3.13}$$

where t_{sps} is the operating time of the SPS; and P_t is the amount of load tripped in the SPS.

Generally for the Tasmanian SPS t_{sps} is around 140 ms after the fault clears.

The critical rate of change of frequency for the studied cases where the HVDC contingency is limiting is shown in Fig. 3-22.

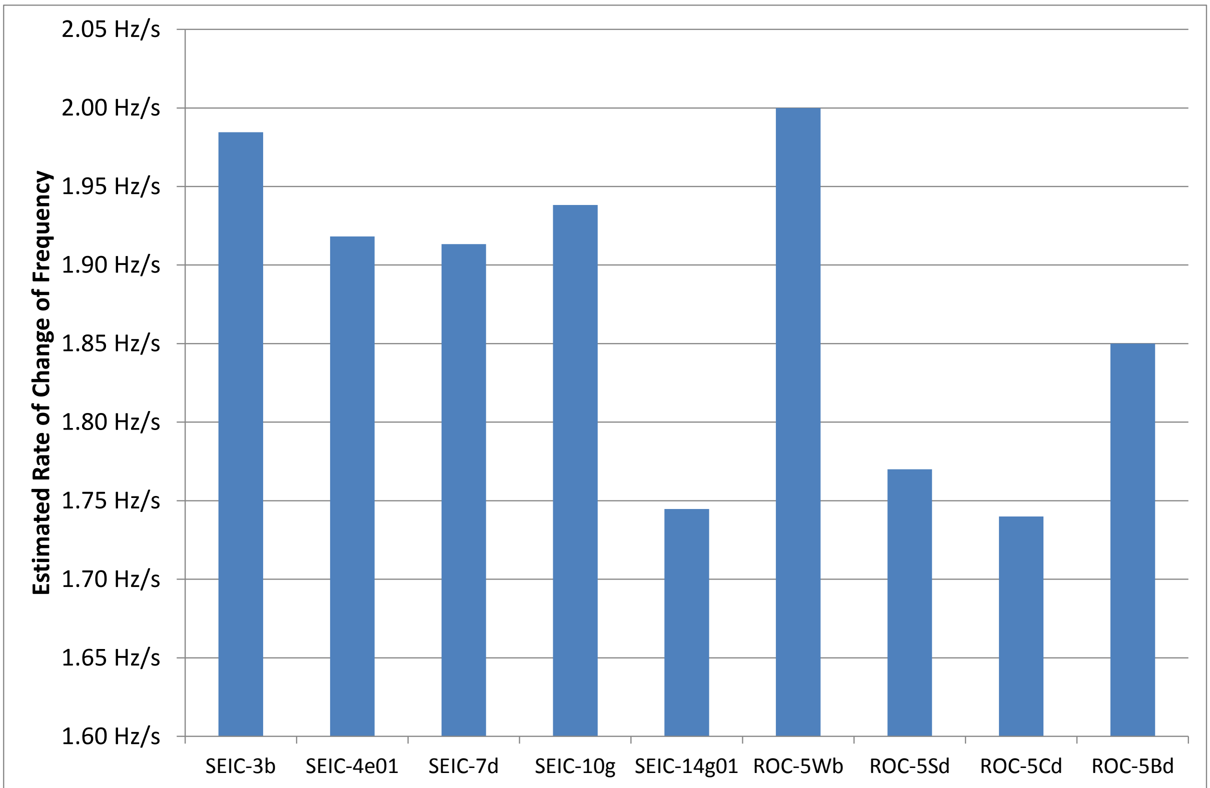

Fig. 3-22 Critical Rate of Change of Frequency for HVDC cases

The critical rate of change of frequency fits within the band between around 1.75 Hz/s and 2 Hz/s.

Loss of the CCGT is in many ways similar to loss of the HVDC. It too has a special protection scheme. The main difference is how the response of the HVDC interconnector must be considered. The HVDC interconnector is equipped with a frequency controller. It attempts to make any frequency disturbance in Tasmania of similar effect in Victoria. For instance if the frequency in Tasmania drops to 48 Hz (the minimum allowable frequency after a single contingency) it will attempt to reduce the Victorian frequency to 49 Hz (the same band in Victoria has a higher frequency). Practically, as Victoria is so much bigger than Tasmania, it will attempt to control Tasmania's frequency to 50 Hz. The interconnector is not big enough to reduce Victoria's frequency to 49 Hz.

The response of the HVDC interconnector to a fault depends on whether it is an inverter or rectifier on the Tasmanian end and what it was transferring before the contingency. As the HVDC interconnector is a line-commutated link it cannot smoothly transition between inverter and rectifier. The response capability (to declining frequency) versus the flow on the link is shown in Fig. 3-23.

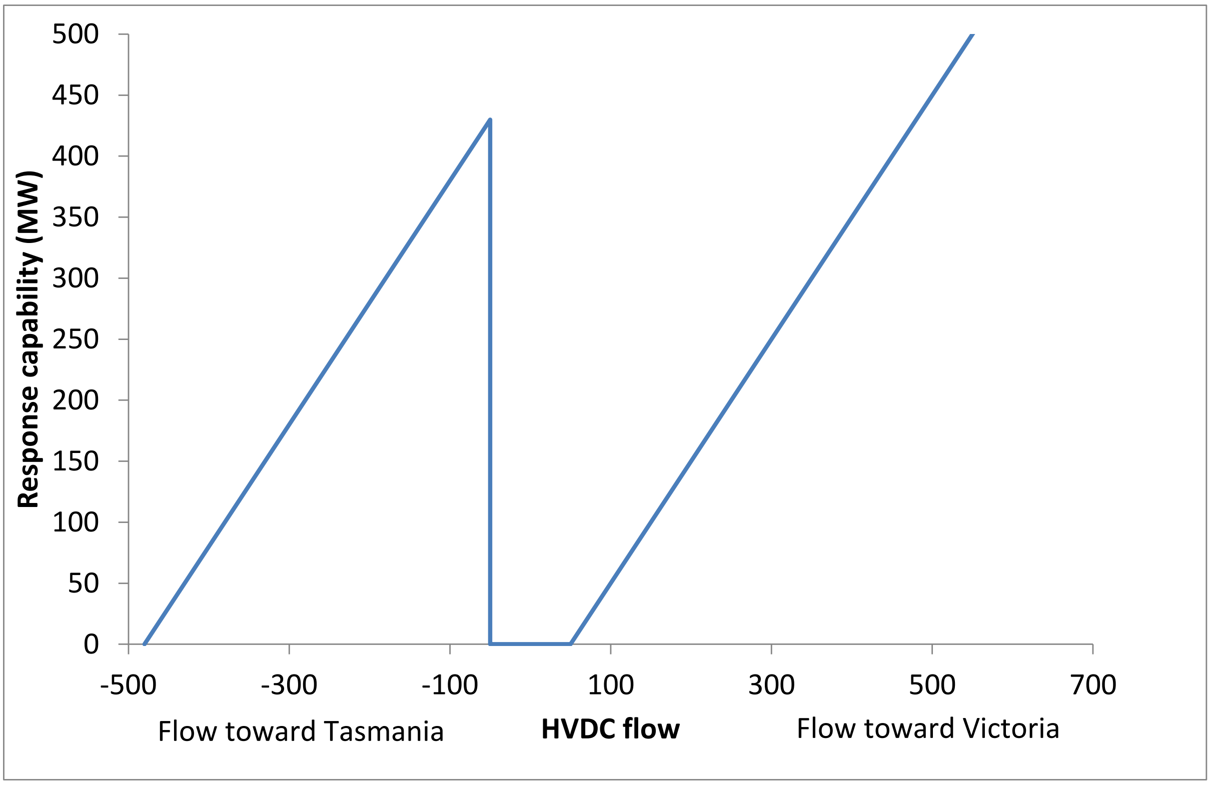

Fig. 3-23 HVDC response capability

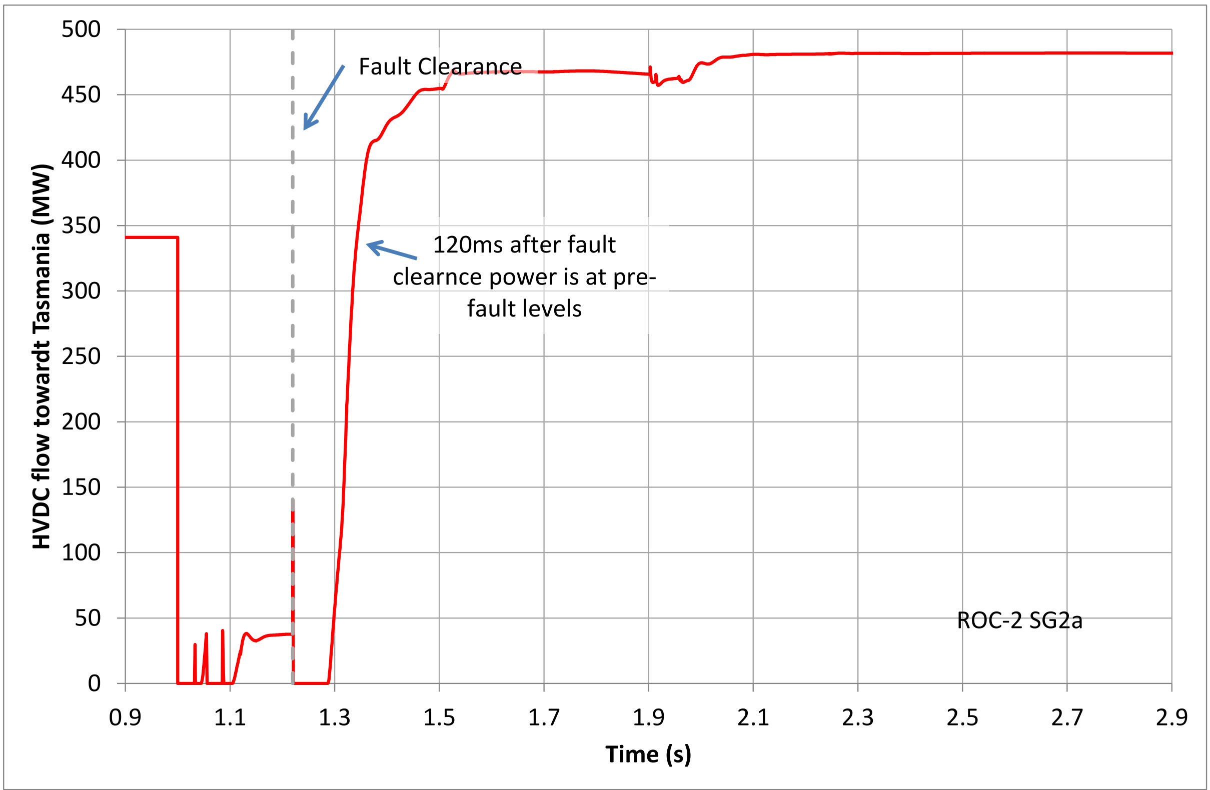

Fig. 3-24 HVDC response to a fault during import

During export from Tasmania the response is different. There are still ramp rate restrictions that result in some time delay before response happens. This is shown in Fig. 3-25.

The HVDC interconnector itself has a response characteristic to faults. This is particularly true when flow is toward Tasmania. The HVDC interconnector response characteristic after a fault close to its terminals in Tasmania is shown in Fig. 3-24.

For application in this metric an idealised response for both directions is used. This response is shown in Fig. 3-26.

The HVDC response is modelled using (3.14).

$$P_{loss} = P_{cont} + P_{wind-loss} - P_{sps} - P_{HVDC} \tag{3.14}$$

where P_{HVDC} is the response of the HVDC, described in (3.15).

$$P_{HVDC} = \begin{cases} 480 - P_f, & P_f < -50 \\ 0, & -50 \geq P_f \geq 50 \\ P_f - 50, & P_f > 50 \end{cases} \tag{3.15}$$

where P_f is HVDC flow with negative flows toward Tasmania

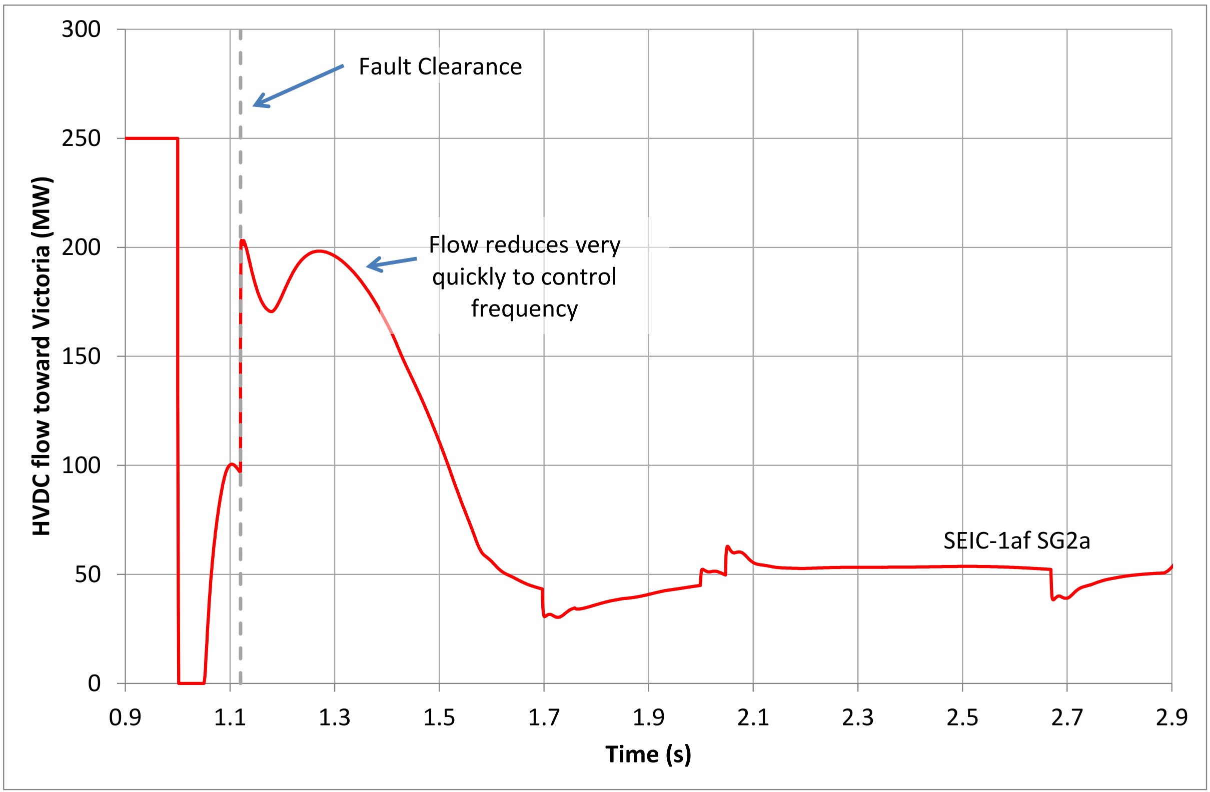

Fig. 3-25 HVDC response to a fault during export

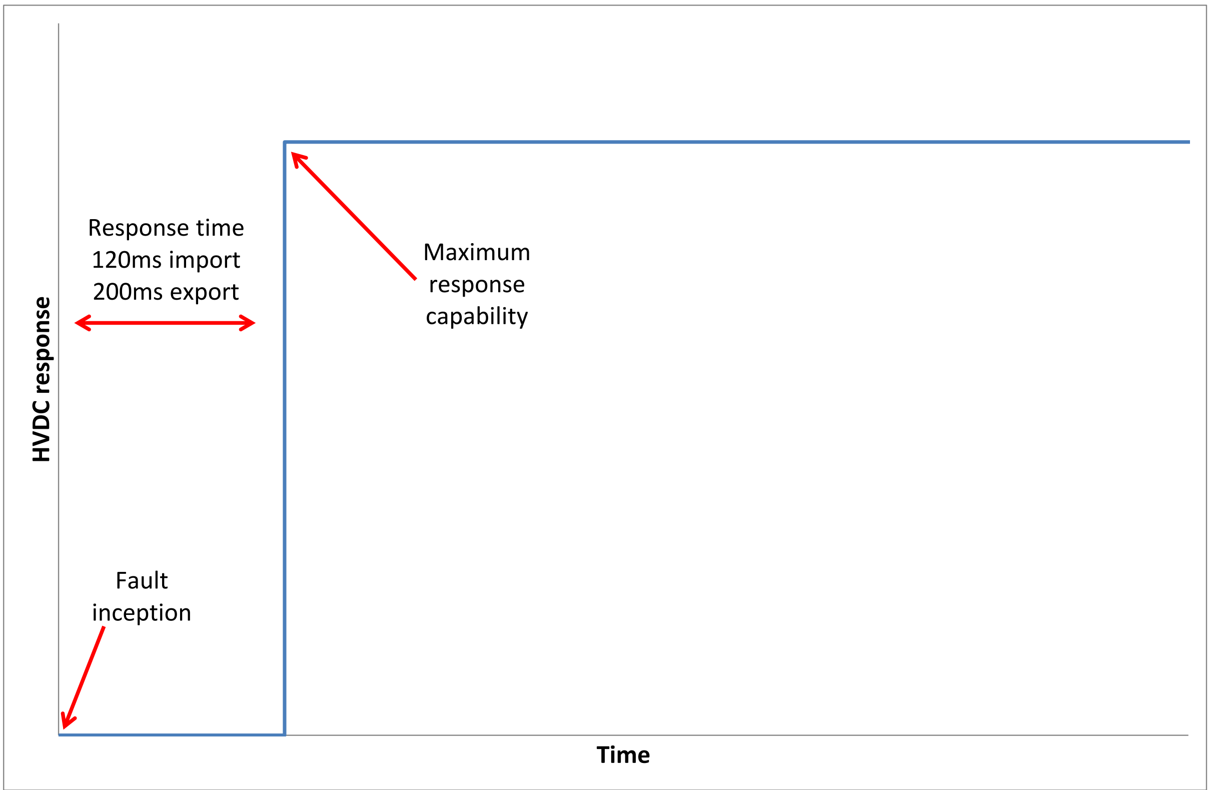

Fig. 3-26 idealised response used in calculation

The critical rate of change of frequency for all cases where the CCGT was the limiting contingency is shown in Fig. 3-27.

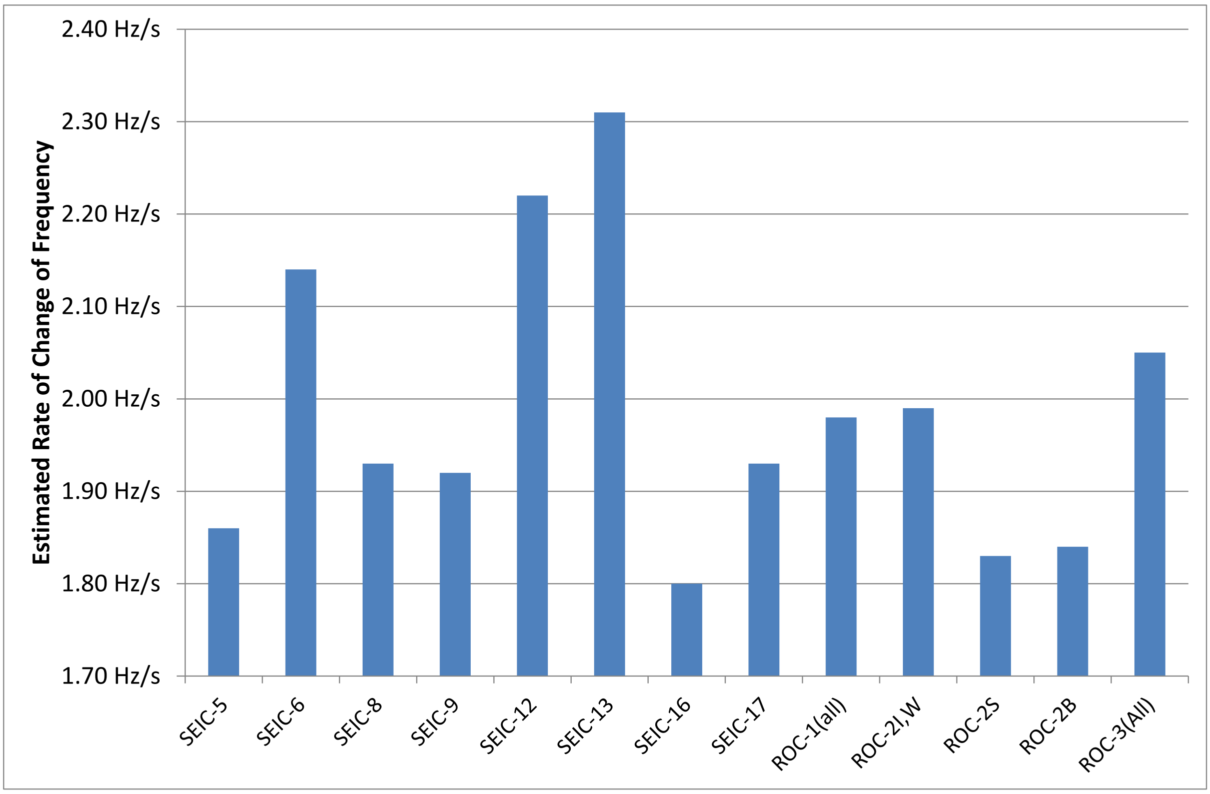

Fig. 3-27 Critical Rate of Change of Frequency for CCGT cases

The critical rate of change of frequency for all cases is between 1.8 Hz/s and 2.3 Hz/s. The higher critical rate of change of frequency cases (particularly SEIC-12 and SEIC-13) were high load cases. Similarly the low critical rate of change case SEIC-16 was a very low load case. This indicates that an improved version of this metric may consider load.

Other synchronous machines can be considered in the same way as the combined cycle gas generator. Smaller machines will generally not have automated load tripping.

In 2012 and 2013 the rate of change of frequency (as predicted by this metric) is shown in Fig. 3-28.

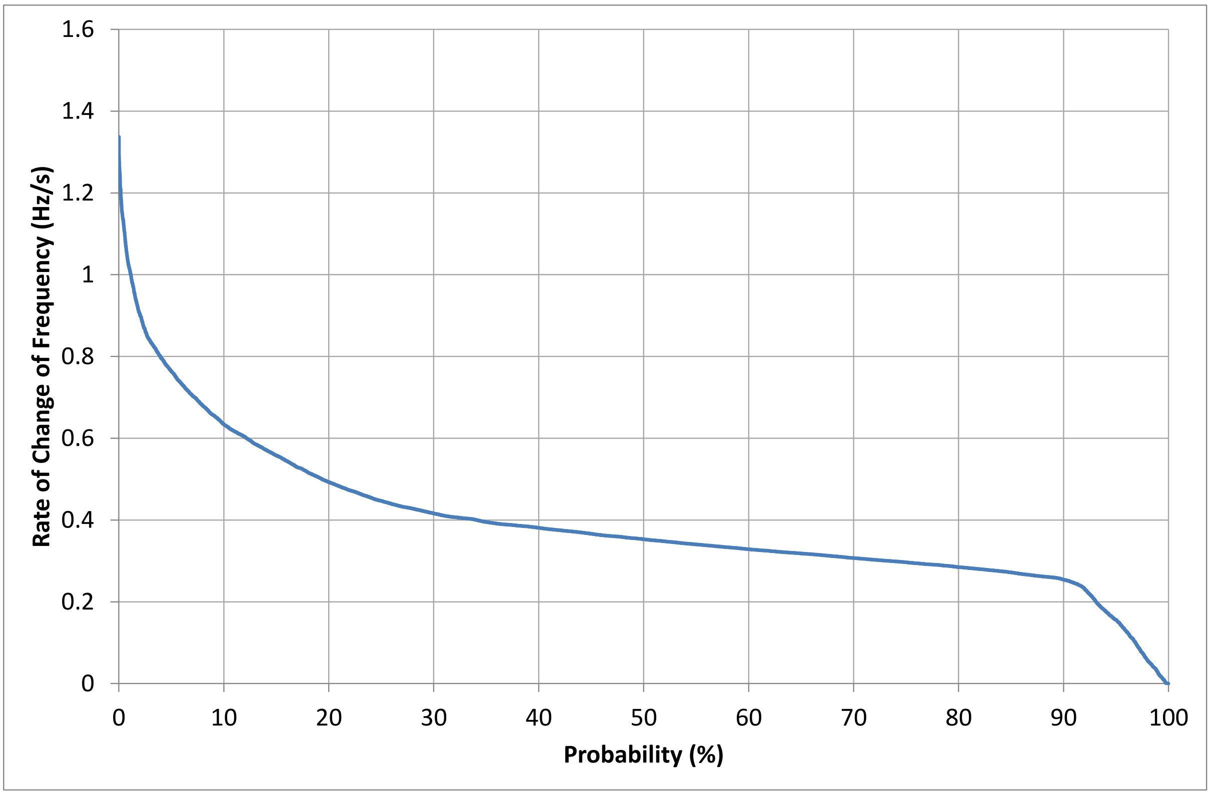

Fig. 3-28 Tasmanian rate of change of frequency in 2012 and 2013

There are no cases shown to be in danger of load shedding due to wind fault ride through response.

The rate of change of frequency metric appears to provide the best indication of system stability with added wind.

3.4.2 Wind plant grid code

In the short term a wind integration metric will work acceptably to prevent system instability but as time passes this metric becomes more limiting. Constraining the system to meet this metric is a market cost and prevents efficient dispatch. It is much better if new entrant wind generation does not cause instability in the first place.

Currently wind plant in Tasmania is connected according to the National Electricity Rules. These rules govern plant performance such as response to contingencies, voltage control, and frequency response. Each standard has two performance levels: automatic and minimum access.

If a plant meets the automatic access standard its connection cannot be refused on the grounds of that standard. These standards are usually relatively onerous. Most wind plant as currently proposed do not meet automatic access in many areas.

If a plant cannot meet the minimum access for any standard it cannot connect. Minimum access standards are usually relatively easy to meet.

The results of this study indicate there are several critical wind farm response characteristics that should be improved. These are:

- Voltage control and reactive power capability;
- Fault ride through recovery; and
- Frequency control

Each of these properties is governed by different system standards.

Voltage control and reactive power capability is governed by S5.2.5.1 (reactive power capability) and S5.2.5.13 (voltage control).

The South Australian wind grid code (see 1.3) requires automatic access as per NER S5.2.5.1. Additionally it requires that half of the reactive power used to meet S5.2.5.1 is 'dynamic'. This additional reactive power, while not necessarily immediately required, will become more useful in the future with more wind generation. A standard similar to South Australia's would aid wind integration in Tasmania as there will be more reactive power reserves to cope with less synchronous generation

The second reactive power standard, NER S5.2.5.13, defines how a generator's reactive power must act. One of the main differences between the automatic and minimum access standards is that the automatic access standard requires a much faster settling time for voltage steps as well as power system stabilisation services. The minimum access standard does not require voltage control at all.

In this study several instances where wind farms tripped due to overvoltage were observed. Many times the wind farms had sufficient reactive power reserves to limit this overvoltage, but the control was too slow. Fast voltage control would reduce the propagation of voltage disturbances. This would particularly be true when wind generation increases and much of the system's voltage control is sourced from wind farms.

For the standard S5.2.5.13, requiring at least the voltage control and response parts of automatic access would aid the connection of future wind generation significantly.

Fault ride through recovery is governed by S5.2.5.5, in particular S.2.5.5 (b) (2). This standard requires:

- A fault contribution of (in total) 400% of the rated current of the generating system;
- Reactive power to control voltage immediately after the fault clears; and
- 95% of the pre-disturbance active power 100ms after the fault clears.

Due to technology limitations 400% of the rated wind farm current may be unrealistic as this would require oversized converters. The second two standards however would clearly, based on the results of this study, be beneficial for power system security. The third one in particular is demonstrated to be the most limiting factor for power system security currently.

A comparison of the response from this study and the automatic access response is shown in Fig. 3-29. Each megawatt of current wind farm response has approximately 0.3 MW of energy deficit for the first second after a fault, compared with the automatic access response which has around 0.1 MW deficit. This is an improvement of two thirds. The $c_{wind\text{-}loss}$ factor in the proposed wind integration metric decreases from around 45% to 12% with this standard.

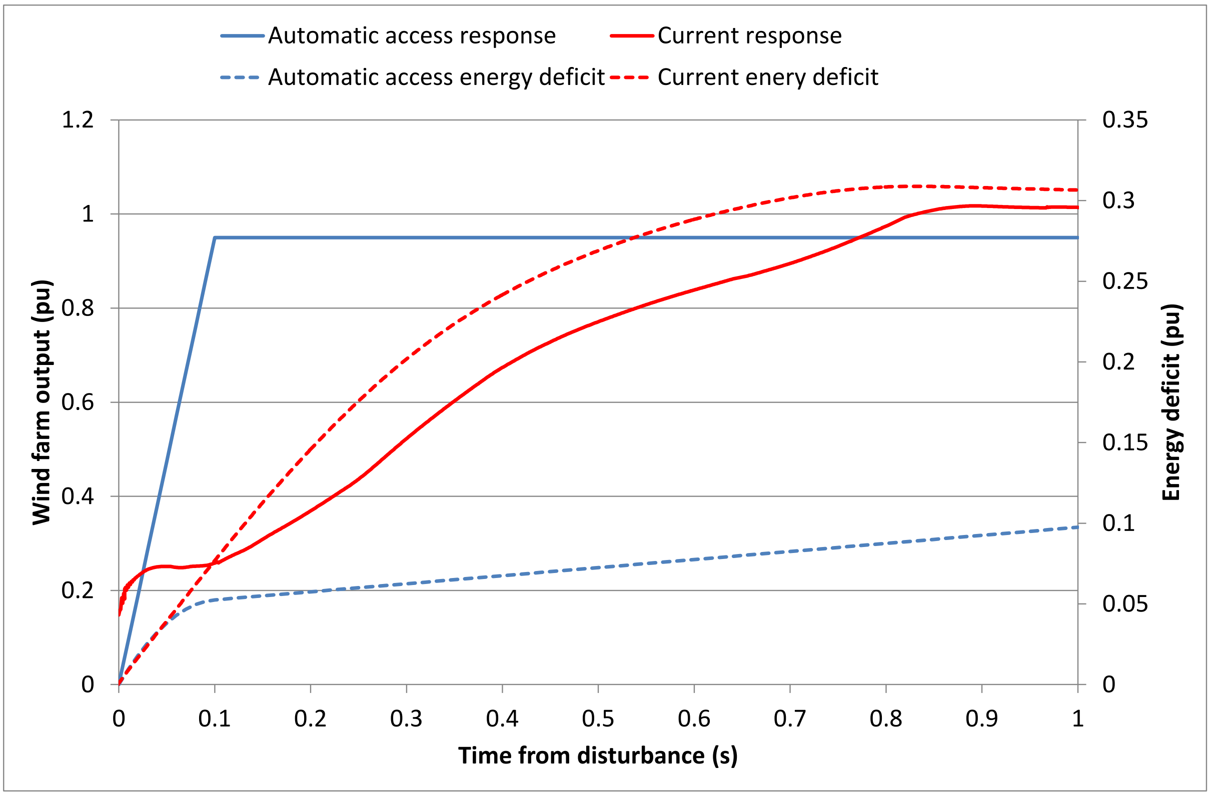

Fig. 3-29 Comparison of current and automatic access response

Clearly any wind grid code in Tasmania must require a fast active power recovery after a fault. Automatic access for this section of S5.2.5.5 is a good starting point.

There were several cases where there were insufficient frequency control services. The NER S5.2.5.11 considers this aspect of plant response.

Automatic access requires the plant actively control frequency in both rising and falling directions.

In the NEM frequency control services are traded on a market just like energy. Both energy and frequency control services are co-optimised. Generally frequency control services are not highly valued. The average frequency control services cost (for all bands) from 2011 week 41 to 2014 week 10 is $0.66/MWh. This compares with energy costs of $30-$40/MWh. A wind farm would generally have to spill wind to provide frequency control services. This means a wind farm would forgo energy at $40/MWh (plus renewable energy certificates at around $35/MWh) for $0.66/MWh of frequency control prices. It is unreasonable to expect a wind farm to do this generally, but there are certain times when frequency control services are much more valuable. This is particularly true when the HVDC interconnector must change direction from import to Tasmania to export from Tasmania. As shown in Fig. 3-23 the connector's frequency control capability drops drastically when it must block to change direction. If there isn't enough frequency control services the connector may be unable to change direction. If wind farms had the capability of providing frequency control they could back down power generation to provide frequency control until the connector changes direction then resume active power production.

As frequency control is a market it is contentious whether frequency control capability should be required or recommended. If there is a shortage of frequency control services the local price of these services is expected to increase. This would thus signal to wind farms operators that they should provide frequency control services. The barrier for adding frequency control to an existing plant is much higher than adding it at construction however. Any requirement for frequency control would be a matter for discussion with policy makers.

In the longer term the lack of inertia from wind farms is expected to become more of an issue. There is no requirement for inertia in the NER, so any requirement for this must go outside the rules. This matter would need to be discussed among policy makers as rules are not the only solution. An inertia market co-optimised with energy and frequency control services would also provide a solution and give current generators an incentive to run to provide inertia support (synchronous condenser mode).

3.5 Summary of small system impact

Wind generation has the potential to introduce many issues in a small power system. The Tasmanian example illustrates many of these issues. These issues are primarily in the areas of frequency and voltage control.

These issues cause several problems, in particular:

- Unwanted under frequency load shedding immediately after a fault that trips a large generator;
- Lack of voltage control causing widespread overvoltage; and
- Instability in certain control systems.

All of these risk the network service provider not meeting its required standards or more importantly disruptions to customer supplies.

The issues are not insurmountable. There are two primary methods of mitigating these issues explored in this study.

In the short term a rate of change of frequency wind integration metric or constraint could be used to maintain system security. This metric would limit the wind generation when there is a risk of unwanted load shedding after a generator fault. The results indicate that in the immediate term rectifying this issue inherently increases system security such that the other issues are no longer a problem.

In the longer term the rate of change of frequency constraint is expected to become overly constraining. Increasingly it would result in inefficient market outcomes. It is better to ensure wind generation doesn't degrade system performance so much in the first place. This is recommended to be implemented via a Tasmanian wind connection code. This code would in particular control the voltage and fault ride through characteristics of the wind plant. Optionally it may require frequency control. This would be within the current framework of the NER.

Inertia can be an increasing issue in small power systems. Requiring inertia to be provided by wind farms may not be the optimal solution. It may be better if inertia is provided through another market that is co-optimised with frequency control. Alternatively a contractual arrangement with existing generators may be preferred. It may be more economically efficient to source from other plant; particularly if there is existing plant capability as there is in Tasmania.

Chapter 4 Conclusion

4.1 Thesis Summary

This thesis aimed to investigate issues with integrating large amounts of wind into a small power system. Tasmania was used as a case study.

An initial review of international experiences showed that the primary issues observed in the jurisdictions with the highest installed capacity of wind were related to wind variability effect on balancing reserves. These power systems were generally large however. A small power system is expected to encounter other issues first.

Some other smaller systems have experienced significant wind generation development. Ireland is a prime example. It is a relatively small system (around 5 GW) and has over 2 GW of installed wind generation. It experienced issues with frequency control – particularly rate of change of frequency. To mitigate for this the following two measures have been implemented:

- A wind integration metric to assess stability boundaries of the power system in real-time; and
- A strong connection code that requires wind generation to have a minimum performance.

The wind integration metric attempts to limit the wind generation as a percentage of total system load. This was found not to apply particularly well to the study system. This was because the primarily hydroelectric generation in the study system could generate at low outputs which breaks the relationship between the number of synchronous generators and total system load.

As the Irish wind integration metric did not apply well to the test system the results were used to derive an alternative. This metric uses the basic inertial response of the power system with inputs from wind farm fault ride through characteristics and the characteristic of other plant to determine the proximity of unwanted load shedding. It outputs an estimated rate of change of frequency derived from the inertial response of the system.

The rate of change of frequency metric considers more power system properties than the inertial response. It has inputs for wind output, contingency size, system inertia, and other energy inputs during the timeframe of the metric (approximately 1 second post fault).

The rate of change of frequency metric was not found to be overly constraining. The current power system would not be constrained by it.

A connection code was found to have merit. If wind farms are required to perform in a certain way their impact could be reduced significantly.

The Irish wind connection code has some useful properties, particularly a requirement for frequency response, although this could be disabled. Other requirements such as active power recovery are in line with what wind farms in the study system could already achieve.

The experience of South Australia was found in some ways to be helpful in the test system. As South Australia is a small part of a large power system South Australia is required to apply a grid code that is written for a much larger system. South Australia's methods of control of wind characteristics by mandating a particular interpretation of this code is easy for developers to understand. If all new wind plant is required to comply with this code many of the issues requiring the wind integration metric will be resolved.

There is some evidence of wind causing existing control systems to become unstable. The exact issues observed in this system may be somewhat unique to the test system. In general it does however illustrate that care needs to be taken to ensure that existing control systems remain stable with significant additional wind generation.

This study has investigated the impact of additional wind generation on a small hydroelectric dominated power system. It has found that some wind properties, especially active power recovery after a fault, can cause frequency control issues. It has studied the experiences of other jurisdictions and concluded that not all of their experiences directly apply to the small system. It has recommended a different wind integration metric that applies to this small power system. A wind connection code was also found to have merit.

4.2 Future work

As wind generation increase the simplified metric described here will become more limiting. In the medium term the matric could be improved by changing some assumptions such as load relief and the effect of particular disturbances on $c_{wind\text{-}loss}$. In the longer term a more complex state estimation based approach would provide a better indication of system security. The need for these improvements could be deferred or eliminated entirely by stronger connection requirements that remove the undesirable response.

4.3 Major contributions

This work could only be compiled with the assistance of many people. In particular I would like to thank:

- Michael Negnevitsky for his guidance and mentoring
- Sead Pasalic for his support and advice
- Doug Pankhurst for his re[ort writing skills
- Cameron Thomas for allowing me to spend the time to finish this work
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Appendix A Wind plant modelling

For the system simulations portion of this study the wind plant is modelled using a generic wind turbine model. This model is written to represent the General Electric (GE) series of wind turbines.

The model is capable of representing both ‘Full Converter’ and ‘Doubly Fed Induction Generator’ turbine types. For this study parameters for the ‘full converter’ turbine type are used. The single line diagram of a wind plant used in this study is shown in Fig. 4-1.

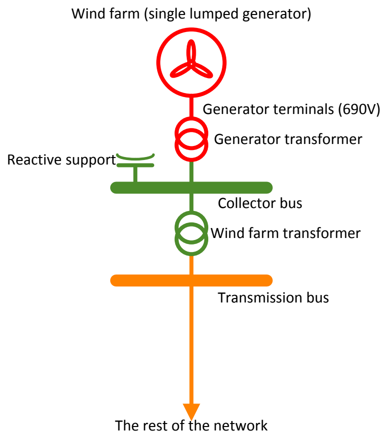

Fig. 4-1 Single line diagram of wind farm

The GE turbines have generally good response characteristics. These characteristics exceed the capabilities of current and proposed wind farms in Tasmania so the parameters used in modelling the wind farms were modified to better reflect the actual capabilities of installed plant. These changes primarily:

- Reduced the speed of voltage control
- Reduced the speed of response post fault

The modified response of the wind farms is shown in Fig. 4-2.

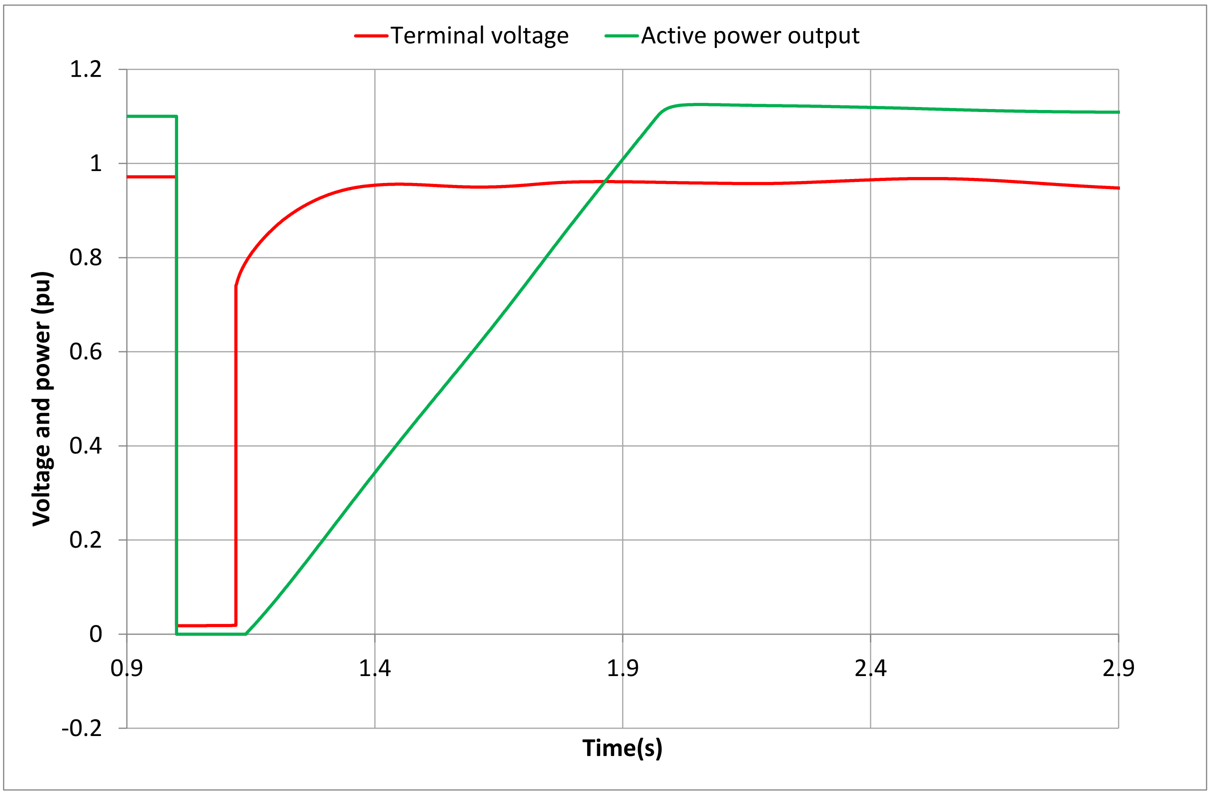

Fig. 4-2 Wind farm modified response

Each wind plant was modelled as a single lumped turbine with some reactive plant. This plant was set based on experience with what is generally installed with wind farms in Tasmania. It generally contains a mixture of dynamic and static plants.

Dynamic reactive plant was modelled using the inbuilt PSSE 'CSTATT' model. This model is relatively basic and only has a single voltage control loop.

Appendix B The Tasmanian electrical system

The Tasmanian electrical system covers mainland Tasmania. It is shown in Fig. 4-3.

This system has a 220 kV backbone with a 110 kV peripheral network. This is mostly transformed directly to distribution voltage of 33kV, 22 kV or 11 kV. There is no meshed sub transmission network.

There is 2,957.25 MW of installed generation in Tasmania. Approximately 2,277.6 MW of this is hydroelectric, 371.9 MW is gas, and 307.75 MW is wind [49]. The hydroelectric generation has considerable storage capacity with around 14,500 GWh of storage. Most of this is in two major storages, Great Lake and Lake Gordon.

There is a single interconnector from Tasmania to mainland Australia. This monopole HVDC link has a capacity of 480 MW import into Tasmania and 630 MW export out of Tasmania. It has a frequency controller. As it is such a large link compared with the size of the Tasmanian electrical system it has two special protection schemes associated with it.

The first scheme is designed to control frequency in Tasmania after loss of the interconnector. It trips generation or load (depending on interconnector flow direction) to limit the effective size of the disturbance. Currently only synchronous machines are used in this scheme.

The second scheme allows the Tasmanian transmission system to operate above its firm capacity[5]. It works by tripping generation to reduce flows after a fault. HVDC interconnector flow is reduced inherently by the frequency disturbance.

Tasmanian maximum demand is around 1700 MW. Average load is around 1200 MW. Around 650 MW of this load is supplied to four major industrial plants.

[5] A transmission corridor is considered 'firm' if loss of one element would not overload the remaining elements.

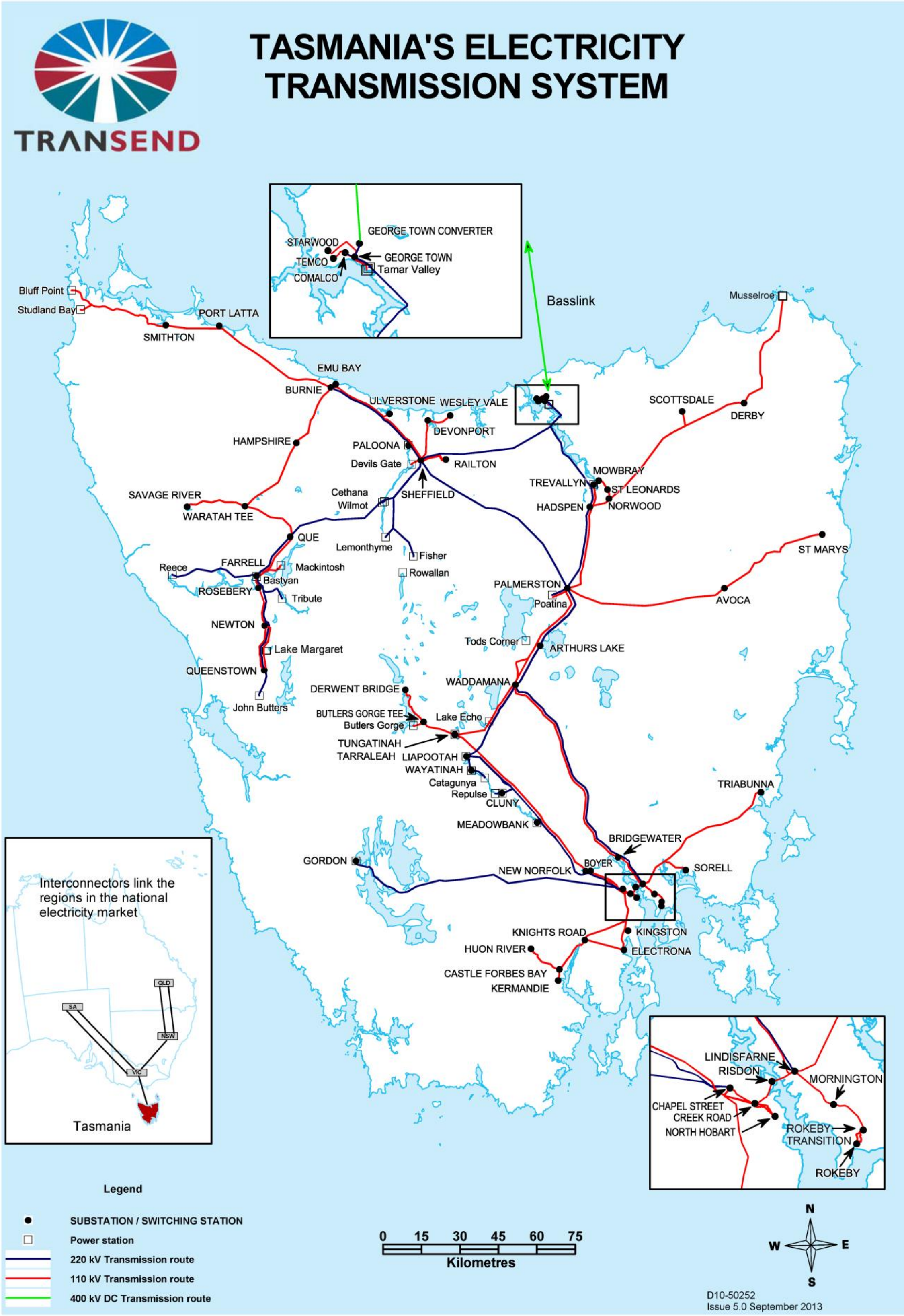

Fig. 4-3 Tasmanian electrical system.

Appendix C Case listing

Case	SNSP	System Inertia	Inertia after largest generator loss	Load	HVDC (+ve is export from Tasmania)	Highest estimated RoCoF	Limiting contingency	Local Fast raise FCAS dispatched	Contingencies which failed
Off-7	14.1%	8267 MWs	7683 MWs	1119 MW	621.4	0.24 Hz/s	HVDC	69.3 MW	0
Off-7GS	32.4%	7384 MWs	6800 MWs	1119 MW	621.4	0.83 Hz/s	HVDC	63.4 MW	0
Off-7L	24.8%	8267 MWs	7683 MWs	1647 MW	621.4	0.73 Hz/s	HVDC	72.0 MW	0
TOV-1	7.3%	8528 MWs	7902 MWs	1191 MW	625.1	0.00 Hz/s	None	107.6 MW	0
TOV-1GS	31.4%	7100 MWs	5387 MWs	1191 MW	626.0	0.88 Hz/s	HVDC	62.3 MW	0
TOV-1L	24.4%	8528 MWs	7902 MWs	1711 MW	625.1	0.71 Hz/s	HVDC	113.8 MW	0
FL-1	50.2%	5359 MWs	3645 MWs	1019 MW	-470.0	1.63 Hz/s	CCGT	119.7 MW	0
FL-1GS	77.5%	4949 MWs	3235 MWs	1019 MW	-310.0	2.31 Hz/s	CCGT	129.6 MW	1
FL-1L	60.2%	6095 MWs	4381 MWs	1577 MW	-470.0	2.83 Hz/s	CCGT	115.9 MW	2
FL-1BL	43.3%	5359 MWs	3645 MWs	1019 MW	87.5	2.66 Hz/s	CCGT	117.8 MW	1
FL-2	44.7%	5984 MWs	4270 MWs	1079 MW	-470.0	1.19 Hz/s	CCGT	121.2 MW	0
FL-2GS	85.3%	5040 MWs	4415 MWs	1079 MW	-470.0	2.26 Hz/s	Hydro	139.1 MW	0
FL-2L	57.5%	5984 MWs	4270 MWs	1599 MW	-470.0	2.71 Hz/s	CCGT	120.5 MW	2
FL-2BL	38.6%	5984 MWs	4270 MWs	1079 MW	88.0	2.06 Hz/s	CCGT	116.4 MW	0
SEIC-1	49.0%	2665 MWs	2039 MWs	928 MW	250.0	3.60 Hz/s	Hydro	62.1 MW	4
SEIC-1a	49.0%	3538 MWs	2912 MWs	928 MW	250.0	2.50 Hz/s	Hydro	66.2 MW	3
SEIC-1af	49.0%	3497 MWs	2871 MWs	928 MW	250.0	2.54 Hz/s	Hydro	60.7 MW	1
SEIC-1b	49.0%	4713 MWs	4087 MWs	928 MW	250.0	1.77 Hz/s	Hydro	63.7 MW	0
SEIC-1bf	49.0%	3983 MWs	3357 MWs	928 MW	250.0	2.17 Hz/s	Hydro	59.9 MW	0
SEIC-2	49.0%	2736 MWs	2251 MWs	928 MW	250.0	5.56 Hz/s	HVDC	44.1 MW	2
SEIC-2f	49.0%	2741 MWs	2256 MWs	928 MW	250.0	2.87 Hz/s	Hydro	52.7 MW	0
SEIC-2a	49.0%	3474 MWs	2989 MWs	928 MW	250.0	3.48 Hz/s	HVDC	50.9 MW	3
SEIC-2b	49.0%	4682 MWs	4197 MWs	928 MW	250.0	2.16 Hz/s	HVDC	60.3 MW	0
SEIC-3f	57.2%	3406 MWs	3074 MWs	1500 MW	-281.3	3.53 Hz/s	HVDC	128.0 MW	3
SEIC-3af	57.2%	4437 MWs	4105 MWs	1500 MW	-281.3	2.70 Hz/s	HVDC	132.0 MW	1
SEIC-3b	57.2%	5992 MWs	5660 MWs	1500 MW	-281.3	1.98 Hz/s	HVDC	131.6 MW	0

Case	SNSP	System Inertia	Inertia after largest generator loss	Load	HVDC (+ve is export from Tasmania)	Highest estimated RoCoF	Limiting contingency	Local Fast raise FCAS dispatched	Contingencies which failed
SEIC-4f	59.0%	3602 MWs	3117 MWs	1500 MW	-308.0	3.37 Hz/s	HVDC	125.1 MW	4
SEIC-4a	59.0%	4321 MWs	3835 MWs	1500 MW	-308.0	2.79 Hz/s	HVDC	125.1 MW	3
SEIC-4b	58.6%	5955 MWs	5469 MWs	1500 MW	-302.0	2.01 Hz/s	HVDC	125.6 MW	1
SEIC-4c	59.0%	6248 MWs	5763 MWs	1500 MW	-308.0	1.92 Hz/s	HVDC	125.8 MW	1
SEIC-4d01	59.0%	6542 MWs	6057 MWs	1500 MW	-308.0	1.83 Hz/s	HVDC	125.7 MW	1
SEIC-4d	59.0%	7168 MWs	6682 MWs	1500 MW	-308.0	1.67 Hz/s	HVDC	125.6 MW	0
SEIC-4e	59.0%	6587 MWs	6102 MWs	1500 MW	-308.0	1.82 Hz/s	HVDC	102.4 MW	0
SEIC-4e01	59.0%	6250 MWs	5765 MWs	1500 MW	-308.0	1.92 Hz/s	HVDC	102.5 MW	0
SEIC-4e02	59.0%	6000 MWs	5514 MWs	1500 MW	-308.0	2.00 Hz/s	HVDC	102.7 MW	1
SEIC-5	61.7%	4032 MWs	2318 MWs	1500 MW	-348.0	4.56 Hz/s	CCGT	117.7 MW	5
SEIC-5a	61.7%	4620 MWs	2906 MWs	1500 MW	-348.0	3.61 Hz/s	CCGT	117.5 MW	4
SEIC-5b	61.7%	5905 MWs	4191 MWs	1500 MW	-348.0	2.48 Hz/s	CCGT	116.4 MW	2
SEIC-5c	61.7%	6805 MWs	5091 MWs	1500 MW	-348.0	2.04 Hz/s	CCGT	115.7 MW	1
SEIC-5d	61.7%	7291 MWs	5577 MWs	1500 MW	-348.0	1.86 Hz/s	CCGT	115.4 MW	0
SEIC-6	38.5%	5374 MWs	3660 MWs	1500 MW	0.0	3.21 Hz/s	CCGT	117.5 MW	1
SEIC-6a	38.5%	6001 MWs	4287 MWs	1500 MW	0.0	2.73 Hz/s	CCGT	115.3 MW	2
SEIC-6b	38.5%	6925 MWs	5212 MWs	1500 MW	0.0	2.24 Hz/s	CCGT	111.8 MW	1
SEIC-6c	38.5%	7494 MWs	5780 MWs	1500 MW	0.0	2.01 Hz/s	CCGT	109.1 MW	1
SEIC-6d	38.5%	8124 MWs	6410 MWs	1500 MW	0.0	1.81 Hz/s	CCGT	123.8 MW	0
SEIC-6d01	38.5%	7787 MWs	6073 MWs	1500 MW	0.0	1.92 Hz/s	CCGT	124.9 MW	0
SEIC-6e	38.5%	7157 MWs	5443 MWs	1500 MW	0.0	2.14 Hz/s	CCGT	114.9 MW	0
SEIC-7	81.3%	3301 MWs	3038 MWs	1018 MW	-250.0	3.30 Hz/s	HVDC	127.2 MW	1
SEIC-7a	81.3%	4068 MWs	3805 MWs	1018 MW	-250.0	2.66 Hz/s	HVDC	128.2 MW	1
SEIC-7b	81.3%	4804 MWs	4541 MWs	1018 MW	-250.0	2.25 Hz/s	HVDC	129.1 MW	1
SEIC-7c	81.3%	5388 MWs	5125 MWs	1018 MW	-250.0	2.00 Hz/s	HVDC	129.3 MW	1
SEIC-7d	81.3%	5873 MWs	5611 MWs	1018 MW	-250.0	1.83 Hz/s	HVDC	129.2 MW	0
SEIC-7d01	81.3%	5623 MWs	5360 MWs	1018 MW	-250.0	1.91 Hz/s	HVDC	129.3 MW	0
SEIC-8	57.3%	4770 MWs	3057 MWs	928 MW	80.0	3.63 Hz/s	CCGT	186.5 MW	1
SEIC-8a	57.3%	5537 MWs	3823 MWs	928 MW	80.0	2.88 Hz/s	CCGT	186.1 MW	1

Case	SNSP	System Inertia	Inertia after largest generator loss	Load	HVDC (+ve is export from Tasmania)	Highest estimated RoCoF	Limiting contingency	Local Fast raise FCAS dispatched	Contingencies which failed
SEIC-8af	57.3%	5537 MWs	3823 MWs	928 MW	80.0	2.88 Hz/s	CCGT	186.1 MW	1
SEIC-8b	57.3%	6206 MWs	4492 MWs	928 MW	80.0	2.45 Hz/s	CCGT	185.6 MW	1
SEIC-8c	57.3%	7094 MWs	5380 MWs	928 MW	80.0	2.04 Hz/s	CCGT	184.9 MW	1
SEIC-8d	57.3%	7388 MWs	5674 MWs	928 MW	80.0	1.93 Hz/s	CCGT	184.6 MW	0
IR-1	59.0%	6542 MWs	6057 MWs	1500 MW	-308.0	1.83 Hz/s	HVDC	125.7 MW	1
IR-1a	59.0%	6524 MWs	6038 MWs	1500 MW	-308.0	1.84 Hz/s	HVDC	125.7 MW	1
IR-1b	59.0%	6518 MWs	6032 MWs	1500 MW	-308.0	1.84 Hz/s	HVDC	125.6 MW	1
IR-2a	59.0%	6584 MWs	6098 MWs	1500 MW	-308.0	1.82 Hz/s	HVDC	101.0 MW	1
IR-2b	59.0%	6622 MWs	6136 MWs	1500 MW	-308.0	1.81 Hz/s	HVDC	100.2 MW	0
SEIC-9	56.7%	5262 MWs	3548 MWs	1018 MW	0.0	3.31 Hz/s	CCGT	151.4 MW	2
SEIC-9a	56.7%	5747 MWs	4033 MWs	1018 MW	0.0	2.91 Hz/s	CCGT	151.3 MW	3
SEIC-9b	56.7%	6373 MWs	4659 MWs	1018 MW	0.0	2.51 Hz/s	CCGT	151.0 MW	2
SEIC-9c	56.7%	7042 MWs	5328 MWs	1018 MW	0.0	2.19 Hz/s	CCGT	150.5 MW	2
SEIC-9d	56.7%	7778 MWs	6064 MWs	1018 MW	0.0	1.92 Hz/s	CCGT	150.1 MW	2
SEIC-9e	56.7%	7778 MWs	6064 MWs	1018 MW	0.0	1.92 Hz/s	CCGT	152.6 MW	1
SEIC-9f	56.7%	7778 MWs	6064 MWs	1018 MW	0.0	1.92 Hz/s	CCGT	154.7 MW	0
SEIC-10	53.8%	4603 MWs	4118 MWs	1817 MW	-400.0	2.85 Hz/s	HVDC	159.4 MW	5
SEIC-10a	53.8%	5332 MWs	4846 MWs	1817 MW	-400.0	2.45 Hz/s	HVDC	157.9 MW	3
SEIC-10b	53.8%	6182 MWs	5696 MWs	1817 MW	-400.0	2.11 Hz/s	HVDC	155.7 MW	1
SEIC-10c	53.8%	6476 MWs	5990 MWs	1817 MW	-400.0	2.01 Hz/s	HVDC	155.0 MW	1
SEIC-10d	53.8%	6751 MWs	6265 MWs	1817 MW	-400.0	1.93 Hz/s	HVDC	154.3 MW	1
SEIC-10e	53.8%	6713 MWs	6227 MWs	1817 MW	-400.0	1.94 Hz/s	HVDC	194.2 MW	1
SEIC-10g	53.8%	6713 MWs	6227 MWs	1817 MW	-400.0	1.94 Hz/s	HVDC	204.4 MW	0
SEIC-11	28.0%	5768 MWs	5143 MWs	1815 MW	250.0	1.45 Hz/s	HVDC	18.9 MW	0
SEIC-12	55.9%	5110 MWs	3396 MWs	1817 MW	-438.5	3.78 Hz/s	CCGT	144.0 MW	3
SEIC-12a	55.9%	6081 MWs	4367 MWs	1817 MW	-438.5	2.92 Hz/s	CCGT	142.7 MW	2
SEIC-12b	55.9%	6974 MWs	5260 MWs	1817 MW	-438.5	2.41 Hz/s	CCGT	140.6 MW	1
SEIC-12c	55.9%	7225 MWs	5511 MWs	1817 MW	-438.5	2.30 Hz/s	CCGT	139.9 MW	1
SEIC-12d	55.9%	7433 MWs	5719 MWs	1817 MW	-438.5	2.22 Hz/s	CCGT	142.5 MW	0

Case	SNSP	System Inertia	Inertia after largest generator loss	Load	HVDC (+ve is export from Tasmania)	Highest estimated RoCoF	Limiting contingency	Local Fast raise FCAS dispatched	Contingencies which failed
SEIC-13	31.8%	6284 MWs	4570 MWs	1817 MW	0.0	2.56 Hz/s	CCGT	91.8 MW	1
SEIC-13a	31.8%	7255 MWs	5541 MWs	1817 MW	0.0	2.10 Hz/s	CCGT	89.5 MW	1
SEIC-13b	31.8%	7255 MWs	5541 MWs	1817 MW	0.0	2.10 Hz/s	CCGT	98.2 MW	0
SEIC-13c	31.8%	6769 MWs	5056 MWs	1817 MW	0.0	2.31 Hz/s	CCGT	95.0 MW	0
SEIC-14	92.8%	1381 MWs	1251 MWs	592 MW	-145.5	5.26 Hz/s	HVDC	87.0 MW	16
SEIC-14a	92.8%	2498 MWs	1872 MWs	592 MW	-145.5	2.85 Hz/s	HVDC	91.8 MW	4
SEIC-14b	92.8%	3317 MWs	2691 MWs	592 MW	-145.5	2.14 Hz/s	HVDC	93.1 MW	1
SEIC-14c	92.8%	3582 MWs	2956 MWs	592 MW	-145.5	1.98 Hz/s	HVDC	93.6 MW	1
SEIC-14d	92.8%	3705 MWs	3079 MWs	592 MW	-145.5	1.91 Hz/s	HVDC	93.5 MW	1
SEIC-14e	92.8%	3705 MWs	3079 MWs	592 MW	-145.5	1.91 Hz/s	HVDC	110.6 MW	1
SEIC-14g	92.8%	4190 MWs	3565 MWs	592 MW	-145.5	1.69 Hz/s	HVDC	93.5 MW	0
SEIC-14g01	92.8%	4049 MWs	3424 MWs	592 MW	-145.5	1.74 Hz/s	HVDC	93.5 MW	0
SEIC-14g02	92.8%	3803 MWs	3177 MWs	592 MW	-145.5	1.86 Hz/s	HVDC	93.5 MW	0
SEIC-14g03	92.8%	3780 MWs	3155 MWs	592 MW	-145.5	1.87 Hz/s	HVDC	94.0 MW	1
SEIC-15	65.6%	2086 MWs	1502 MWs	592 MW	261.5	3.28 Hz/s	Hydro	134.0 MW	2
SEIC-15a	65.6%	3057 MWs	2473 MWs	592 MW	261.5	1.97 Hz/s	Hydro	132.7 MW	1
SEIC-15b	65.6%	3394 MWs	2810 MWs	592 MW	261.5	1.73 Hz/s	Hydro	132.1 MW	0
SEIC-15c	65.6%	3283 MWs	2699 MWs	592 MW	261.5	1.81 Hz/s	Hydro	133.6 MW	0
SEIC-15c01	65.6%	3153 MWs	2569 MWs	592 MW	261.5	1.90 Hz/s	Hydro	132.9 MW	0
SEIC-15c02	65.6%	3012 MWs	2428 MWs	592 MW	261.5	2.01 Hz/s	Hydro	133.6 MW	0
SEIC-15d	65.6%	2858 MWs	2274 MWs	592 MW	261.5	2.15 Hz/s	Hydro	133.7 MW	1
SEIC-16	75.7%	3549 MWs	1835 MWs	592 MW	150.0	4.70 Hz/s	CCGT	126.1 MW	1
SEIC-16a	75.7%	5067 MWs	3354 MWs	592 MW	150.0	2.53 Hz/s	CCGT	131.0 MW	1
SEIC-16b	75.7%	5693 MWs	3979 MWs	592 MW	150.0	2.13 Hz/s	CCGT	131.5 MW	1
SEIC-16c	75.7%	5987 MWs	4273 MWs	592 MW	150.0	1.98 Hz/s	CCGT	131.9 MW	1
SEIC-16d	75.7%	6281 MWs	4567 MWs	592 MW	150.0	1.85 Hz/s	CCGT	132.3 MW	1
SEIC-16e	75.7%	6556 MWs	4842 MWs	592 MW	150.0	1.80 Hz/s	CCGT	132.6 MW	0
SEIC-17	65.8%	4136 MWs	2423 MWs	592 MW	0.0	3.45 Hz/s	CCGT	165.4 MW	1
SEIC-17a	65.8%	5107 MWs	3394 MWs	592 MW	0.0	2.44 Hz/s	CCGT	165.5 MW	1

Case	SNSP	System Inertia	Inertia after largest generator loss	Load	HVDC (+ve is export from Tasmania)	Highest estimated RoCoF	Limiting contingency	Local Fast raise FCAS dispatched	Contingencies which failed
SEIC-17b	65.8%	5733 MWs	4019 MWs	592 MW	0.0	2.05 Hz/s	CCGT	165.4 MW	1
SEIC-17c	65.8%	5996 MWs	4282 MWs	592 MW	0.0	1.93 Hz/s	CCGT	165.3 MW	0
ROC-1	44.4%	7236 MWs	5523 MWs	1300 MW	0.0	2.10 Hz/s	CCGT	201.1 MW	1
ROC-1Ia	44.4%	7573 MWs	5860 MWs	1300 MW	0.0	1.97 Hz/s	CCGT	200.4 MW	0
ROC-1Wa	42.7%	7236 MWs	5523 MWs	1245 MW	0.0	1.98 Hz/s	CCGT	203.6 MW	0
ROC-1Sa	44.4%	7236 MWs	5523 MWs	1300 MW	0.0	1.98 Hz/s	CCGT	201.1 MW	0
ROC-1Ca	45.3%	7236 MWs	5523 MWs	1275 MW	0.0	1.98 Hz/s	CCGT	201.1 MW	0
ROC-1Ba	44.4%	7236 MWs	5523 MWs	1300 MW	0.0	1.98 Hz/s	CCGT	201.1 MW	0
ROC-2	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	2.55 Hz/s	CCGT	172.7 MW	2
ROC-2Ia	71.3%	6153 MWs	4440 MWs	1300 MW	-350.0	2.35 Hz/s	CCGT	172.6 MW	1
ROC-2Ib	71.3%	6294 MWs	4581 MWs	1300 MW	-350.0	2.28 Hz/s	CCGT	172.5 MW	1
ROC-2Ic	71.3%	6902 MWs	5189 MWs	1300 MW	-350.0	1.99 Hz/s	CCGT	172.4 MW	0
ROC-2Wa	70.7%	5816 MWs	4103 MWs	1230 MW	-350.0	2.33 Hz/s	CCGT	170.7 MW	1
ROC-2Wb	68.6%	5816 MWs	4103 MWs	1124 MW	-350.0	1.99 Hz/s	CCGT	166.0 MW	0
ROC-2Sa	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	2.35 Hz/s	CCGT	172.7 MW	1
ROC-2Sb	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	2.02 Hz/s	CCGT	172.7 MW	1
ROC-2Sc	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	1.99 Hz/s	CCGT	172.7 MW	1
ROC-2Sd	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	1.83 Hz/s	CCGT	172.1 MW	0
ROC-2Ca	72.9%	5816 MWs	4103 MWs	1273 MW	-350.0	2.36 Hz/s	CCGT	172.6 MW	1
ROC-2Cb	76.2%	5816 MWs	4103 MWs	1217 MW	-350.0	2.01 Hz/s	CCGT	172.1 MW	1
ROC-2Cc	76.2%	5816 MWs	4103 MWs	1217 MW	-350.0	1.98 Hz/s	CCGT	172.6 MW	1
ROC-2Cd	76.8%	5816 MWs	4103 MWs	1207 MW	-350.0	1.92 Hz/s	CCGT	172.7 MW	0
ROC-2Ba	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	2.02 Hz/s	CCGT	172.6 MW	1
ROC-2Bb	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	1.98 Hz/s	CCGT	172.6 MW	1
ROC-2Bc	71.3%	5816 MWs	4103 MWs	1300 MW	-350.0	1.84 Hz/s	CCGT	172.6 MW	0
ROC-3	39.1%	5718 MWs	4005 MWs	1300 MW	175.0	2.21 Hz/s	CCGT	121.7 MW	1
ROC-3Ia	39.1%	5965 MWs	4252 MWs	1300 MW	175.0	2.08 Hz/s	CCGT	121.2 MW	0
ROC-3Wa	39.1%	5718 MWs	4005 MWs	1244 MW	175.0	2.05 Hz/s	CCGT	121.7 MW	0
ROC-3Sa	39.1%	5718 MWs	4005 MWs	1300 MW	175.0	2.05 Hz/s	CCGT	117.7 MW	0

Case	SNSP	System Inertia	Inertia after largest generator loss	Load	HVDC (+ve is export from Tasmania)	Highest estimated RoCoF	Limiting contingency	Local Fast raise FCAS dispatched	Contingencies which failed
ROC-3Ca	39.8%	5718 MWs	4005 MWs	1275 MW	175.0	2.05 Hz/s	CCGT	121.7 MW	0
ROC-3Ba	39.1%	5718 MWs	4005 MWs	1300 MW	175.0	2.05 Hz/s	CCGT	121.7 MW	0
ROC-4	44.4%	4852 MWs	4226 MWs	1300 MW	0.0	2.30 Hz/s	Hydro	171.0 MW	1
ROC-4Ia	44.4%	5183 MWs	4557 MWs	1300 MW	0.0	2.13 Hz/s	Hydro	171.0 MW	0
ROC-4Wa	41.7%	4852 MWs	4226 MWs	1217 MW	0.0	2.12 Hz/s	Hydro	172.7 MW	0
ROC-4Sa	44.4%	4852 MWs	4226 MWs	1300 MW	0.0	2.13 Hz/s	Hydro	171.0 MW	0
ROC-4Ca	45.4%	4852 MWs	4226 MWs	1272 MW	0.0	2.12 Hz/s	Hydro	171.5 MW	0
ROC-4Ba	44.4%	4852 MWs	4226 MWs	1300 MW	0.0	2.14 Hz/s	Hydro	171.0 MW	0
ROC-5	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	2.33 Hz/s	HVDC	234.3 MW	1
ROC-5Ia	75.2%	5738 MWs	5575 MWs	1300 MW	-400.0	2.10 Hz/s	HVDC	233.8 MW	1
ROC-5Ib	75.2%	6032 MWs	5869 MWs	1300 MW	-400.0	1.99 Hz/s	HVDC	233.6 MW	1
ROC-5Ic	75.2%	6326 MWs	6163 MWs	1300 MW	-400.0	1.90 Hz/s	HVDC	233.6 MW	1
ROC-5Id	75.2%	6416 MWs	6253 MWs	1300 MW	-400.0	1.87 Hz/s	HVDC	233.1 MW	0
ROC-5Wa	74.5%	5182 MWs	5019 MWs	1195 MW	-400.0	2.09 Hz/s	HVDC	235.3 MW	1
ROC-5Wb	72.2%	5182 MWs	5019 MWs	1185 MW	-400.0	2.00 Hz/s	HVDC	232.7 MW	0
ROC-5Sa	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	2.10 Hz/s	HVDC	234.4 MW	1
ROC-5Sb	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	2.00 Hz/s	HVDC	234.4 MW	1
ROC-5Sc	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	1.90 Hz/s	HVDC	234.4 MW	1
ROC-5Sd	75.0%	5182 MWs	5019 MWs	1303 MW	-400.0	1.77 Hz/s	HVDC	234.1 MW	0
ROC-5Ca	74.3%	5182 MWs	5019 MWs	1255 MW	-400.0	2.10 Hz/s	HVDC	234.8 MW	1
ROC-5Cb	73.9%	5182 MWs	5019 MWs	1235 MW	-400.0	2.00 Hz/s	HVDC	235.6 MW	1
ROC-5Cc	73.5%	5812 MWs	5649 MWs	1214 MW	-400.0	1.90 Hz/s	HVDC	235.4 MW	1
ROC-5Cd	71.4%	5182 MWs	5019 MWs	1205 MW	-400.0	1.74 Hz/s	HVDC	234.5 MW	0
ROC-5Ba	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	2.10 Hz/s	HVDC	234.3 MW	1
ROC-5Bb	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	2.00 Hz/s	HVDC	234.3 MW	1
ROC-5Bc	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	1.90 Hz/s	HVDC	234.3 MW	1
ROC-5Bd	75.2%	5182 MWs	5019 MWs	1300 MW	-400.0	1.85 Hz/s	HVDC	234.3 MW	0
ROC-6	41.2%	4423 MWs	3797 MWs	1300 MW	100.0	2.26 Hz/s	Hydro	119.1 MW	0