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Tasmania

John Pierce
Australian Energy Market Commission
PO Box A2449
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National Electricity Amendment (Network Support and Control Ancillary Services) Rule 2010 [ERC 0108]

Dear Mr Pierce

The Office of Energy Planning and Conservation (OEPC) would like to thank the Commission for the invitation to comment on Network Support and Control Ancillary Services Rule Change Consultation Paper.

The OEPC provides support for the Director of Energy Planning, a statutory role provided for by the *Energy Co-ordination and Planning Act 1995*. The Director has powers under the Act (section 12) to form committees for the purpose of considering and advising on energy matters specified by the Minister. As such the Director has formed the Electricity Technical Advisory Committee (ETAC). The primary role of ETAC is to provide Government with technical advice relating to the reliability of the electricity supply network and its safe and secure operation (system security).

ETAC has recently provided the Director a paper outlining some of the issues that may arise in the Tasmanian electricity network with growth in the level of asynchronous generation in the state. We provide this paper as part of the Network Support and Control Ancillary Services rule change process since we believe it highlights a number of key issues that may well apply more broadly across the National Electricity Market. Also, a number of the recommendations directly impact on the provision of Network Support and Control Ancillary Services.

Thus, we recommend the paper to you and hope it assists in your deliberations.

If you have any questions, please contact Tim Astley on (03) 62 333 091.

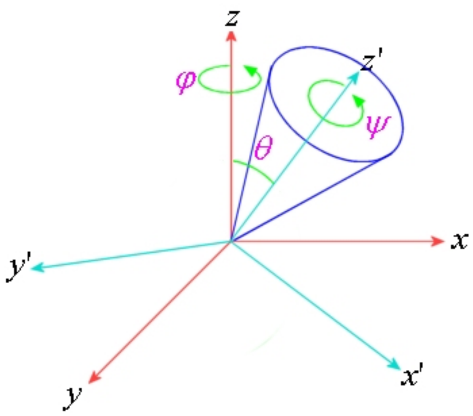
Yours sincerely

Bob Rutherford
Deputy Secretary

3 September 2010

(Trim: D10/60016)

Inertia Issues Working Group



Discussion Paper

Rev	Date	Revision Description
0	29/04/2010	DRAFT for discussion
0.2	28/06/2010	Working DRAFT provided for information to ETAC
1.0	21/7/2010	For final review by IIWG
1.1	27/8/2010	Updated after feedback from IIWG and other stakeholders'. For submission to ETAC
1.2	1/9/2010	Final version submitted
1.3	3/9/2010	Minor changes to sections 1.1 & 1.4

CONTACT

This document is the responsibility of ETAC.

Contents

1. SUMMARY REPORT

1.1. INTRODUCTION

It has been identified that Tasmania has an excellent wind resource[1] as a result of the Roaring 40s weather pattern, and it is expected that there will be considerable interest from parties wanting to utilise this resource.

However, in practice it will be economic, technical and regulatory issues which determine the magnitude of the viable wind resource.

Some anticipated Tasmanian power system operating scenarios of low demand (over night during summer), high Basslink import and high Wind Turbine Generator (WTG) output gave rise to concerns over the ability of existing systems and arrangements to support the integration of all the potential renewable (asynchronous) generation[2].

In response to those concerns, in April 2009 the Tasmanian Electricity Technical Advisory Committee (ETAC) developed a Terms of Reference (TOR) for the Inertia Issues Working Group (IIWG) to provide ETAC with advice on any issue that will or may result from a reduction in the system inertia of the Tasmanian power system resulting from the anticipated penetration of asynchronous (low inertia) renewables into the generation mix.

The original intent of this paper was to consider one potentially limiting factor that of insufficient power system inertia. However in considering a planning horizon of three to five years, during which time it is possible that over 500MW of WTG capacity could be in service, it is important to identify all issues that could impact adversely on the development of renewable energy generation in Tasmania.

This document meets ETAC's request for information. It is not intended to recommend solutions to the issues identified, but rather to raise the profile of the issues and initiate discussions so that these emerging issues and the potential impacts of limiting factors can be managed in a considered manner and not limit potential developments of new renewable energy sources in Tasmania. It is considered that various parties would have accountability for exploring and implementing solutions to the issues identified in this paper.

For example; the Australian Energy Market Commission (AEMC) noted, in its final report on the "Review of Energy Market Frameworks in light of Climate Change policies"[3] that existing energy market frameworks were sufficient to allow the progression of processes to address inertia. The report further noted that processes were already underway to examine inertia issues in some regions of the National Electricity Market (NEM) and that these should be allowed to run their course before specific Rule changes were considered. The final report also foreshadowed that the Australian Energy Market Operator (AEMO) would be coordinating a review of inertia related issues for South Australia[4] adding that AEMO was

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[1] Wind Power modelling and Analysis of Simulated Output for Regions in Tasmania, 3Tier, 23 April 2010, A study for Transend Networks

[2] Asynchronous generation is generation which is not synchronised (directly coupled) to the power system. Historically most generators have been synchronous generators refer Appendix 2.

[3] Chapter 9, page 116," Review of Energy Market Frameworks in light of Climate Change Policies – Final Report, AEMC, 30 September 2009

[4] Page 32 AEMO submission to 2nd Interim Report of the AEMC Review of Energy market Frameworks in light of Climate Change Policies, June 2009

well placed to coordinate such a review as they are likely to involve those parties most knowledgeable of the relevant issues.

As a consequence; it is the working group's desire that ETAC refer this report onto AEMO and the AEMC, as the appropriate parties responsible for system security and market development.

Whilst the initial intent was aimed at WTGs the findings are also pertinent to all forms of asynchronous generation.

1.2. FINDINGS

The Inertia Issues Working Group (IIWG) re-affirms that the connection of asynchronous generators will introduce additional technical challenges for the secure operation of the Tasmanian power system. Equally challenging will be the market design changes required to foster the most efficient and equitable regulatory mechanisms that enhance the National Electricity Objective given more complex technical parameters.

1.2.1. Inertia

The IIWG also observes that the key issues around system inertia are associated with:

- high levels of asynchronous generation (with no or low inertia) and/or Basslink import displacing conventional inertia providing generation;
- rapid increases in the required amounts of fast raise and fast lower market ancillary services when the inertia falls below a critical level coincident with potential shortages in supply of market ancillary services; and
- significant reduction in "post credible contingent system inertia".

We have found that at this time the issues of system inertia are unique to Tasmania but in the future with increasing penetration of asynchronous generation they may become an issue for all regions of the NEM.

1.2.2. Fault level

An additional impact of increasing penetration of asynchronous generation is the reduction in fault level. Whilst system inertia effects are global across Tasmania, insufficient fault level impacts tend to be localised. The relief of one, through the dispatch of synchronous generation may or may not relieve the impacts of the other.

Studies undertaken for this report[5] indicate that, in the next three to five years if sufficient synchronous plant is dispatched to meet the post-contingency Basslink import fault level requirements to ensure stable Basslink import then fast raise requirements can be readily met. This may not be realistically obtainable and hence Basslink import may be limited. Currently to avoid Basslink import limitations additional system inertia is pre-emptively dispatched for fast raise service requirements. There are concerns that further increase in asynchronous generation will exacerbate meeting the fault level and inertia constraints.

If there are either zero transfers across Basslink or Basslink is exporting, the required amount of Tasmanian synchronous generation should be sufficient to support the proposed new asynchronous generation without the need for undue quantities of either fast raise

[5] Refer section 6 FAULT LEVEL ISSUES of this report

service or fast lower service. As only limited studies were undertaken for this report the IIWG suggest that this is an issue that requires further investigation.

Similarly, if system inertia is maintained using synchronous plant at levels that do not give rise to undue quantities of either fast raise service or fast lower service then, depending on the location of the synchronous plant, the George Town fault level requirement to support Basslink imports may also be satisfied.

In the longer term the requirement for sufficient fault level to maintain satisfactory quality of supply in regard to voltage fluctuations (known as flicker) and harmonics, may restrict connection of asynchronous generation unless that generation can contribute to the fault level or there are mechanisms to ensure adequate fault level separately from Basslink import stability requirements.

It is noted that the two issues discussed above (i.e. inertia and fault level) have materially different impacts on the power system. While inertial issues manifests themselves in terms of reduced operational efficiency, the fault level issue impacts directly on system security and quality of power supply.

These issues will be significant in defining the realisable wind resource and the IIWG feel that addressing them early will help to foster confidence in the potential to develop renewable energy in Tasmania.

1.3. RELATED ISSUES

In addition to the inertia and fault level issues, the displacement of synchronous generation (without appropriate mitigation) gives rise to:

- reduction in sources of reactive power for voltage control;
- concerns regarding the maximum size of generation connected by single circuits and the impact on fast raise ancillary service requirements in an environment of low system inertia;
- displacement in the energy dispatch of market ancillary service providers;
- commutation failure of Basslink arising from frequency controller response to some contingencies;
- high rates of change of system frequency and reduced time for protective action; and
- potential reductions in power system stability.

The impacts of generator contingency size are not limited to power imbalance, but also include the consequences of the loss of related services of inertia, fault level, reactive power and power system damping[6].

Currently the market impacts of these issues are masked by the fact that some market participants respond to commercial incentives to mitigate potentially adverse impacts themselves.

[6] If a power system is suitably damped the power system settles in a finite time to a new steady operating condition following a disturbance and the power system is said to be stable. If the system does not settle to a stable operating condition, it is considered to be underdamped.

In the knowledge of the consequences of a constraint binding, generators outside the central dispatch process can provide services that impact on the factors within constraints with the aim of avoiding a constraint binding; for example, pre-emptive operation of generation in synchronous compensator mode to provide fault level and inertia. This gives rise to questions of providing services that are not subject to central dispatch but deliver benefits to the market as a whole in the absence of mechanisms that fully compensate the provider.

While these indirect incentives can provide the desired services it is far from guaranteed as market participants don't have any direct obligations for system security and can be largely driven by commercial factors that may change over time.

Currently the technical capability of the power system is described using mathematical equations called constraint equations. One of the requirements for the formulation of these equations is that they must be linear[7]. Current constraint formulation philosophies will find it extremely difficult to manage the issues of fault level and system inertia as these issues are highly non-linear and discontinuous.

1.4. MARKET MECHANISMS

The IIWG is a technical working group and as such it has only made passing comment on possible market mechanisms for the provision of and recompense for services; in particular, system inertia and contributions to fault level, that are neither recognised through market ancillary services nor non-market ancillary services mechanisms.

Thus this report highlights the need for incentives to provide these services in the form of a mechanism that places a value on those services that will be required not only to support Basslink imports but also the introduction of large scale asynchronous generation.

We note there are market mechanisms available to AEMO[8] that can ensure these issues are managed in the short term. However, we are aware that there may be long lead times required to develop and implement changes to market arrangements. Should national processes prove a major constraint on renewable generation development in Tasmania the State Government may wish to explore other mechanisms to best manage the issues of low fault level and low inertia and more broadly other issues that may arise from the displacement of synchronous generation by asynchronous generation.

There are a number of technical remedies which could be used to help manage these issues. One obvious solution, currently available is to use existing hydroelectric generators running in synchronous condenser mode. Other possible remedies include requiring the WTGs to provide (some) inertia and fault level, or the Transmission Network Service Provider (TNSP) installing a dedicated synchronous condenser.

These technical remedies however all involve some cost. There are additional costs associated with running a generator as a synchronous condenser principally, increased wear and cavitation issues due to the increased frequency in starting and stopping and operating a

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[7] Or at least piecewise continuous monotonically increasing linear equations, refer AEMO Constraint Formulation Guidelines, Document reference 170-0040, 21 May 2010

[8] Such as the ability to direct generators

long way from its peak efficiency point[9] likewise implementing special control schemes on WTGs will involve additional cost and reduce the efficiency of the WTGs.

Current market arrangements provide no indications (price signals) as to how these issues should be managed as the existing market arrangements have not been developed with the intent of trying to incentivise parties, to supply inertia and fault level.

It is suggested that the Tasmanian electricity supply industry give consideration to exploring the most efficient mechanisms for managing these issues and proactively lobbies for a market framework that enables future Tasmanian WTG developments.

1.5. ISSUES FOR CONSIDERATION

Whilst not recommending a mechanism that enables the connection of asynchronous generation without unduly impacting on the operational flexibility of the Tasmanian power system the following options are proposed for consideration and discussion:

- development of minimum access standards; for example, frequency control capability, minimum inertia, and minimum fault level contribution which could then be enforced through the relevant rules, whether national or Tasmanian;
- the application of National Electricity Rules (Rules) clause S5.2.5.12[10] in relation to intra-regional and inter-regional transfer limitations;
- the introduction of new market ancillary services covering inertia and fault level;
- a review of AEMO's Market Ancillary Service Specification (MASS) to provide for inertia contributions;
- a review of the Tasmanian frequency operating standards for network events;
- the development of new non-market ancillary services, network support and control ancillary service of inertia and fault level;
- clarify the provision of network support and control services; and
- the adequacy of constraint equations to manage the issues in this paper.

It is recommended that ETAC make this report available to AEMO and the AEMC, to support further investigations into the impact of a reduction in the availability of services traditionally provided by generators, on system security and market efficiency.

[9] Maximum efficiency points are typically 65% to 85% of rated output.

[10] National Electricity Rules clause S5.2.5.12, Impact on Network Capability"

2. DISCUSSION

Over the last several years concerns have been raised around the provision of fast raise and fast lower market ancillary services that are required to maintain compliance with the Frequency Operating Standards. These concerns arose in the Tasmanian context due to the possibility of increasing requirements for these services concurrent with shortages in supply in an environment of Basslink operation, comparatively large size of credible generator loss, increasing entry of non-synchronous generation and reducing system inertia.

It has been estimated that there is about 1,750MW of potential wind generation projects[11] being contemplated in Tasmania. Currently there is 140MW of wind generation connected to the transmission system[12], with another 900MW of wind generation the subject of a number of connection enquiries. Of these connection enquiries, two projects Mussleroe and Cattle Hill are being actively progressed. If both of these projects are delivered then there will be approximately 540MW of installed WTGs in Tasmania within five years.

Over night during summer, the Tasmanian load can be as low as 900MW. If you assume 60 % yield from the wind turbine generators and full Basslink import, theoretically this would result in overnight synchronous generation of less than 200MW comprising either gas fired or hydro-electric generation.

In practice this situation would be prevented from occurring as it would result in a non viable power system because of low fault level preventing Basslink import, the need for currently unobtainable levels of market ancillary services and other operational issues. With the existing arrangements either the new wind generators, Basslink import (or both) would have to be limited to maintain a secure power system. The application of Rules clause S5.2.5.12 would also be pertinent to the outcomes.

In late 2008 this gave rise to concerns regarding the connection of large numbers of WTGs to the Tasmanian Power system and ETAC forming the IIWG in April 2009. The IIWG consists of representatives from:

- AEMO;
- Hydro Tasmania;
- Roaring 40s (for part of the work);
- Transend; and
- consultant technical experts.

The purpose of this document is to promote discussion on the efficient and equitable management of current and potential future power system issues resulting from the connection of increasing levels of asynchronous generation.

Whilst the original view was that low Tasmanian power system inertia and its consequences for the requirements for and supply of fast raise services was the key issue; the IIWG has found that system inertia is just one symptom of a broader issue when considering constraints on the Tasmanian power system operation.

[11] Transend report, Future wind generation in Tasmania study, section 1.3 Potential Future Wind Generation Connections in Tasmania

[12] 75MW at Studland Bay and 65MW at Bluff point

This paper is structured to provide:

- a brief introduction to technical issues and current market mechanisms;
- details of initial inertia related concerns;
- analysis of interrelationships between fault level, inertia, and constraints pertinent to Basslink dispatch;
- a description of the range of services provided by synchronous generators; and
- concluding remarks.

3. BACKGROUND

This section provides a high level technical introduction to and explanation of the key issues of power system inertia and fault level as well as a description of the market mechanisms that are pertinent to the delivery of services required to enable AEMO to meet its power system security obligations.

3.1. SERVICES PROVIDED BY GENERATORS

In the past virtually all system demand was met by synchronous generators with a few small sized induction generators. HVDC links, such as Basslink, connected relatively large systems that were either remote from each other or had different control principles. With the decreasing cost of power electronics and improved technology variable speed generation and the HVDC connection of weaker systems has become more common.

There has also been increased interest in static energy sources capable of injecting energy from energy storage devices. The Rules adopt a technology neutral approach. However while all new generation sources provide energy to the system other services provided by conventional rotating plant are either not supplied or supplied in limited quantities. Another observed trend is a focus on the increased efficiency of supply (energy conversion) which is often delivered at the cost of downgrading services such as frequency control and regulation.

Typical services delivered to a power system by conventional generators include:

- energy (active power, MW);
- reactive power control;
- frequency control (FCAS);
- inertial response;
- supply of fault current;
- fault ride through (ability to continue to operate through disturbances); and
- output modulation (damping).

All of the above listed services are required for reliable and secure operation of the power system. However some of these services are more critical than others and therefore they have attracted strict functional requirements while other services (inertial response and supply of fault current) have historically been available in sufficient quantities and therefore they have attracted much less regulatory attention.

	Synchronous generators	Asynchronous generators		
		Induction generators	DFIGs[13] (partial conversion)	Full conversion[14]
Energy supply	Y	Y	Y	Y
Reactive power	Y	N	Limited	Y
Frequency control	Y	Usually not	Capable but not practical	Capable but not practical
Inertia	Y	Y	N[15]	N
Fault current	Y	Limited	N	N
Fault ride through	Y	Limited	Limited	Limited
Damping	Y	N	N	Capable

Table 1 Summary of service capability for different types of generation.

Table 1 shows that the system services delivered by asynchronous generation can be limited.

3.2. SYSTEM INERTIA

The inertia of a body is its tendency to resist change in its motion whether that motion is spinning or in a straight line. The inertia of a body is measured in kg-m^2 whilst the inertia of a power system is the rotational energy measured in MWs (MJoules) that is stored in the rotating machines whose speeds vary synchronously with each other.

If one generator is disconnected from the power system then, in the short term until system reserves react, there will be insufficient energy to supply the load on the rest of the system, and the system slows down (frequency drops) as energy stored in the spinning machines is used to make up the shortfall. If the power system has low inertia it will slow down very quickly as the energy stored in the rotating machines is quickly used up. As a consequence it can be difficult to maintain system frequency within the Frequency Operating Standards.

Wind turbines using conventional induction generators are sensitive to frequency and provide inertial response in a similar manner to traditional generation. However most modern WTGs are variable speed machines (which allow for either a wide range of operating speeds by using “full converter” induction generators or a narrow range of operating speeds such as “double fed” induction generators). By using power electronics to vary rotor speed independent of grid frequency they can thus maintain optimum wind turbine power output for a given wind speed. As a result they are insensitive to grid frequency and provide no inertia response unless the control systems are programmed to do so [for example, GE Energy WindINERTIA™ Control][16].

Increasing use of HVDC links, variable speed generation and static energy sources (batteries, photo-voltaics, variable speed flywheels) connected via converters that displace synchronous generation give rise to reductions in equivalent system inertia and stored rotational energy. This can be mitigated by stipulating minimum access standards that emulate inertia by means of controls that modulate generation with changes in system frequency.

[13] DFIG Doubly Feed Induction Generator – common type of wind turbine generator

[14] This applies to all converters from wind turbines to HVDC and energy storage connection

[15] At least one manufacturer offers this capability but there are no incentives available to use these turbines in Tasmania

[16] http://www.gepower.com/prod_serv/products/renewable_energy/en/wind_plan_optimization.htm

While outside the scope of this paper, it is noted that discussion has commenced on the possibility of a second link with mainland Australia at some point in the future and depending on the technology employed in this link it may either increase or reduce the problems identified above.

The concept of system inertia is described in more detail in Appendix 1.

3.3. FAULT LEVEL

By strict definition fault level corresponds to the overall amount of current that will flow into a fault (short circuit) at a point in the power system when operating at rated (or pre-fault) voltage prior to a fault. Fault level is measured in giga volt amperes (GVA) which is the product of pre-fault (or rated) voltage and current flowing during a fault.

Fault level is an important consideration in managing power systems as the fault level is a measure of the strength of the power system. A strong power system will have a high fault level (>10GVA), while weak systems will have a low fault level (<2GVA). A high fault level increases the ability of a power system to withstand disturbances and minimise fluctuations arising from turning on and off loads and the switching of network elements. It means that faults are easily detected and will be cleared quickly and as a result, the fault will have less impact on the power system as a whole[17].

The grid connected WTGs currently installed in Tasmania are asynchronous and as such supply very limited fault current and therefore do not contribute to system fault level to the same extent as traditional synchronous generators.

3.4. MARKET ARRANGEMENTS

The Rules provides for AEMO to procure market ancillary services as described in Rules clause 3.11.2. Market ancillary services are procured through the spot market and provide the capability of controlling the level of generation or load to arrest changes in system frequency.

The dispatch of energy and market ancillary services is co-optimised with the aim to maximise the value of spot market trading.

The Rules also have mechanisms for network service providers, in conjunction with AEMO, to negotiate network user performance standards in accordance with schedule S5.2 for generators, S5.3 for customers and S5.3a for market network service providers. In addition, as described in clause 3.11.4(a), AEMO can procure network control ancillary services required to enable compliance with power system security obligations. Under clause 3.11.3(j), network service providers must advise AEMO of all ancillary services or similar services to be provided by a registered participant under a Connection Agreement.

[17] Assuming that the power system equipment has been designed to survive that level of fault current.

Since its entry into the National Electricity Market (NEM) on 29 May 2005, Tasmania has experienced issues with the provision of fast raise services and to a lesser extent fast lower services. This was further exacerbated by the AEMC Reliability Panel's 18 December 2008 review into the Tasmanian Frequency Operating Standards. In order to mitigate the impacts of the revised "tighter" Tasmanian Frequency Operating Standards for generator contingency events, the Reliability Panel determined that:

> *"the size of the largest single generator event is limited to 144MW, which can be implemented for any generating system with a capacity that is greater than 144MW by the automatic tripping of load."*

It should be noted that a similar limit to contingency size was not determined for network events that give rise to disconnection of generation even though the same operating frequency band of 48Hz to 52Hz applies.

It is noted that while the AEMC's Reliability Panel has recognised reserve impacts (such as FCAS) of increasing the size of the generator contingency it has not recommended a means of compensation for the increased loss of inertia and loss of fault current contribution.

As a result of the revised Tasmanian Frequency Operating Standards and to improve its management of system frequency, AEMO on 29 October 2009 when setting the required amount of local Tasmanian fast raise service took into account the:

1. loss of inertia as a result of disconnection of the generator with the highest scheduled generation. This has the effect of increasing the required amount of fast raise services for a generator event.
2. reduction in Tasmanian system inertia with increasing Basslink import that increases the amount of local fast raise services.

The raise service constraint equations for loss of Basslink were redesigned to improve their accuracy by taking into account Tasmanian inertia, demand and Basslink flows. The redesign effectively established minimum system inertia requirements. This minimum inertia constraint impacts on Basslink imports. If system inertia falls below levels that are a function of Tasmanian demand, the allowable level of Basslink import is reduced. This has the effect of providing greater Tasmanian access to global raise services at times that otherwise would potentially require increased quantities of raise services concurrent with a potential shortage in supply of those services.

Generation is able to anticipate this constraint and, in responding to commercial incentives, provide system inertia by placing into service plant that would not be otherwise scheduled by the National Electricity Market Dispatch Engine (NEMDE).

A disadvantage of this mechanism is that the provision of the inertia is not recognised directly in the market.

In relation to fault level, since the commissioning of Basslink there has been a constraint equation that limits Basslink imports based on the George Town fault level. The fault level constraint formulation discounts the highest fault level contribution to the next highest contribution. This ensures that there is sufficient fault level post contingency, to support continued stable Basslink operation.

Potentially this issue may have much wider implications as minimum fault level constraints could be applied to all network nodes. This value is used for coordination of the quality of the power supply and operating below the minimum fault level may result in a significantly distorted voltage waveform.

In order to reduce the requirement for fast lower services for the loss of Basslink on export the Basslink Frequency Control System Protection Scheme (FCSPS) algorithm was changed to eliminate the difference between Basslink export and the amount of generation to be tripped. A similar change for Basslink import has not been implemented.

Following its "Intervention Pricing Methodology" review into the arrangements for FCAS transfer over Basslink, NEMMCO[18] in its mid 2008 Market Management System (MMS) release implemented the 'NEMDE Second Solve' project. The release introduced an additional NEMDE run to increase the feasible solution space when Basslink is capable of transferring market ancillary services. The first NEMDE run uses the relevant initial conditions, while the second run assumes that Basslink is unable to transfer market ancillary services by not using the Basslink Frequency Controller. Actual dispatch is determined by the run with the lower objective function. This was primarily aimed at reducing the occurrences of Basslink counter price flows.

It should also be noted that Rules clause S5.2.5.12, Impact on Network Capability" provides:

> **Automatic access standard**
>
> (a) The *automatic access standard* is a *generating system that* must have *plant* capabilities and *control systems* that are sufficient so that when *connected* it does not reduce any *inter-regional* or *intra-regional power transfer capability* below the level that would apply if the *generating system* were not *connected*.
>
> **Minimum access standard**
>
> (b) The *minimum access standard* is a *generating system that* must have *plant* capabilities, *control systems* and operational arrangements sufficient to ensure there is no reduction in:
>
> > (1) the ability to *supply Customer load* as a result of a reduction in *power transfer capability*; and
> >
> > (2) *power transfer capabilities* into a region by more than the combined *sent out generation* of its *generating units*.

The tendency in applying this clause is towards the minimum access standard.

[18] The National Electricity Market Management Company (NEMMCO) was replaced by AEMO in 2009.

4. INITIAL CONCERNS

The understanding that increased use of asynchronous energy sources can lead to a reduction in the inertia of the Tasmanian power system gave rise to the following concerns:

1. the scale of the impact on power system security;
2. substantial increases in the requirement for raise service and lower market ancillary services with consequent weaknesses in co-optimisation with the energy market and increases in Tasmanian spot price; and
3. the inability to effectively utilise and develop the available wind resource in Tasmania.

AEMO's market ancillary service (MAS) calculator[19] shows a significant increase in the fast services required for low inertia systems. This is illustrated below in Figure 1 for loss of AETV's combined cycle gas turbine assuming that raise services are not available from the mainland across Basslink; for example with Basslink at low export or very high import. Figure 1 demonstrates that under some Tasmanian system conditions that adding inertia reduces R6 requirements. It is noted that generators operating in synchronous condenser mode contribute to inertia and fault current the same as during normal generation operation. It is also noted that increasing system inertia to reduce fast raise and lower requirements is effective only up to a certain level of system inertia.

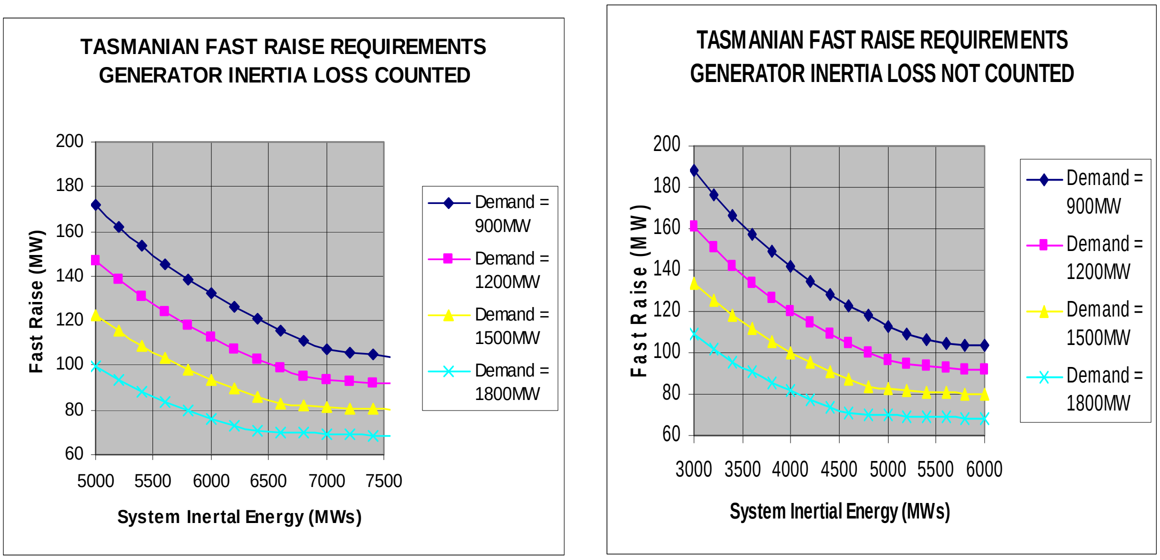

Figure 1 Tasmanian Local Fast Raise Requirement Loss of CCGT, 144MW, no global raise available, revised TFOS

At the time of the formation of the IIWG, the dispatch mechanism did not provide incentives to increase Tasmanian system inertia in circumstances where there is a shortage of fast raise services. Since September 2009 when AEMO introduced revised constraint formulations associated with the implementation of the new Tasmanian frequency operating standards such incentives were introduced by constraining Basslink imports to increase access to global raise services in the event of a shortage of local Tasmanian raise services.

[19] The FCAS calculator is a spreadsheet tool which calculates the FCAS requirements for a given system dispatch.

4.1. SYMPTOMS OF LOW INERTIA

Key symptoms of low inertia power systems are:

- increased fast raise FCAS requirements;
- high rates of change of frequency (ROCOF) are possible;
- longer time taken to recover from a disturbance; and
- decreasing coordination of under frequency load shedding scheme (UFLS) with other system protection schemes[20].

Other symptoms of displacing synchronous generation with wind generation and/or HVDC import include:

- reduced availability of fast raise and lower sources;
- impact on the ability of the power system to recover from successful clearance of faults; that is, transient stability;
- impact on the ability to damp oscillations during recovery from small disturbances; that is dynamic stability; and
- increased possibility of over-response during a frequency disturbance resulting in the frequency moving quickly from under supply to oversupply or vice versa.

The contribution of rotating machine injection/absorption of energy during frequency excursions is limited by the magnitude of the frequency change. For example, a 4% frequency drop will release 8% of the stored inertial energy. For a 5000MWs inertial energy system and loss of 150MW of generation the initial rate of change of frequency would be 0.75Hz/sec as determined by the initial inertial power contribution of 144MW. If market ancillary services arrest the frequency drop to 4% within 6 seconds the average power contribution from inertial energy would be 65MW. However the inertial energy used to arrest the frequency drop has to be restored as the frequency recovers.

4.2. RATE OF CHANGE OF FREQUENCY & UFLS

Lower inertia power systems tend to decelerate and accelerate faster resulting in increased rate of change of frequency (ROCOF) and greater frequency changes for the same sized disturbance. For example, as above the loss of a 150MW generator on a 5000MWs inertial energy system results in an initial ROCOF of 0.75Hz/sec; whilst for a 3000MWs inertial energy system this increases to 1.25Hz/sec.

The maximum permissible ROCOF is limited by the performance of Basslink and wind generation as they have been specified and tested to operate with changes of up to ±3Hz/sec. However it is noted that the operation of some power electronic devices is only specified up to ±1Hz/sec.

With the increased connection of wind and under high Basslink import, the ROCOF in Tasmania prior to the Basslink SPS operation could reach 4Hz/sec for a period of less than 0.85 seconds.

[20] AETV GCS and Basslink FCSPS

The system inertia influences the time taken for the frequency excursion to stabilise (return to steady state). In Tasmania before the commissioning of Basslink, the minimum frequency would be reached within 6 to 7 seconds. With loss of Basslink under import, the minimum frequency occurs often at 5 or 6 seconds. With the AETV CCGT plant remaining in service the minimum frequency occurs at 8 to 10 seconds. For comparison in the larger mainland power system the same minimum occurs in 12 to 15 seconds.

The ROCOF has a significant impact on the time available for under frequency load shedding (UFLS) back up protective actions allowing for the discrimination in the size of the supply/demand imbalances. Transend at present is forced to use ROCOF signal to accelerate the UFLS tripping to achieve adequate discrimination. However, if the power system becomes lighter the time available will be reduced and may not be sufficient to keep the frequency within appropriate frequency bands. The implication of this is that there may be tripping of UFLS loads for single credible contingencies[21].

The power system should be able to survive normal (i.e. credible) contingencies without the operation of emergency protection schemes such as the UFLS. The operation UFLS schemes for credible contingencies would not only be in contravention to the NER, but would be highly disruptive to large major industrial customers.

5. IS INERTIA A GLOBAL OR LOCAL TASMANIAN ISSUE

Inertia similar to the frequency is a global issue in a synchronously interconnected system. An asynchronously interconnected system, for example Tasmania with the mainland, does not necessarily have common frequency/inertia performance characterises across the system. As is the case for Basslink an asynchronous connection may be equipped with a frequency controller that emulates synchronous operation by modulating power transfers in proportion to fluctuations from a reference frequency.

The frequency controller on Basslink allows the transfer of market ancillary services according to the frequency controller objective function that links the Tasmanian and Victorian frequency standards. However at times when Basslink is not operating, or operates close to a low or high limit, or is blocked during power flow reversal, the transfer of market ancillary services is either not available or is very limited.

The interconnected mainland power system is predominantly synchronously connected, with small asynchronous links operating in parallel with the main synchronous interconnections. While the South Australian system is facing large increases in wind generation the inertial impacts are not the same as in Tasmania as the South Australian system is synchronously interconnected. However; should South Australia lose the synchronous interconnection, inertia may become a much more significant problem. It should be noted that on 16 February 2010 ElectraNet and AEMO jointly announced their

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[21] The NER defines a credible contingency event as: A "*credible contingency event*" means a *contingency event* the occurrence of which *AEMO* considers to be reasonably possible in the surrounding circumstances including the *technical envelope*. Without limitation, examples of *credible contingency events* are likely to include:

> (1) the unexpected automatic or manual *disconnection* of, or the unplanned reduction in capacity of, one operating *generating unit*; or
> (2) the unexpected *disconnection* of one major item of *transmission plant* (e.g. *transmission line*, *transformer* or *reactive plant*) other than as a result of a three phase electrical fault anywhere on the *power system.*

intention to conduct a joint feasibility study of transmission development options that could economically increase the interconnector transfer capability between South Australia and other National Electricity Market (NEM) load centres. The study is important in light of South Australia's extensive renewable energy resources and their ongoing development potential.

6. FAULT LEVEL ISSUES

Power system simulations[22] were carried out by Transend to demonstrate concerns associated with a lack of system inertia under increasing wind farm penetration. The study was conducted to determine whether the Tasmanian power system would be in a secure operating state for a range of system inertias while honouring minimum fault level and market ancillary service constraints.

It was found that with high wind farm penetration of around 500MW output and Basslink import the Tasmanian power system becomes unstable following the loss of the Aurora Energy Tamar Valley (AETV) combined cycle gas turbine as a result of a transmission line fault.

The study case ensured that the pre-fault fault system satisfied the Basslink fault level constraint. That is, post the loss of the highest fault level contributing generator, in this instance the CCGT, the post-fault fault level would be sufficient to continue to support the pre-fault level of Basslink import.

However, loss of generation gives rise to reductions in Tasmanian frequency that initiates Basslink frequency controller action resulting in rapid and large increases in Basslink import. The post-fault fault level is then insufficient to support the increased Basslink import after Basslink's recovery from the first commutation failure. This gives rise to Basslink instability and repetitive commutation failures (in reality after two attempts Basslink will block).

Another contributing factor is the fault ride through response of the wind farms reducing their output causing further deterioration of Tasmanian system frequency. The increased frequency differential between Tasmania and Victoria contributes to a stronger response by the Basslink frequency controller.

The study established that increasing the fault level above that required by the Basslink fault level constraint equation, by connecting more synchronous machines to the Tasmanian system either operating in the synchronous compensator[23] mode or generating, stabilised the system.

Simply increasing system inertia by increasing the number of generators electrically remote from George Town, did not on its own make the case stable.

Alternative mechanisms to avoid repetitive commutation failures are:

- reduce the response of the Basslink frequency controller which would have consequences for the Basslink network control system protection scheme and market ancillary service transfers;

[22] Using PSS/E simulation software.

[23] A generator operating as a synchronous compensator is synchronised (magnetically coupled) to the power system

- suspend frequency controller action or temporarily reduce frequency controller gain after commutation failures;
- limit power flow on recovery from commutation failure; or
- ensuring that wind generators are electrically remote from the critical fault thus avoiding operation of the fault ride through control and minimising the frequency excursion.

It was observed that if the Basslink response (i.e. going heavily into import) is reduced by as little as 20MW then sustained commutation failure can be avoided.

The following figures illustrate the performance of Basslink under sustained commutation failure and stable operation. They indicate the initial response to the fault being the reduction in import power flows to zero followed by frequency controller action to restore the Tasmanian power system frequency then either unstable (figure 2) or stable (figure 3) operation.

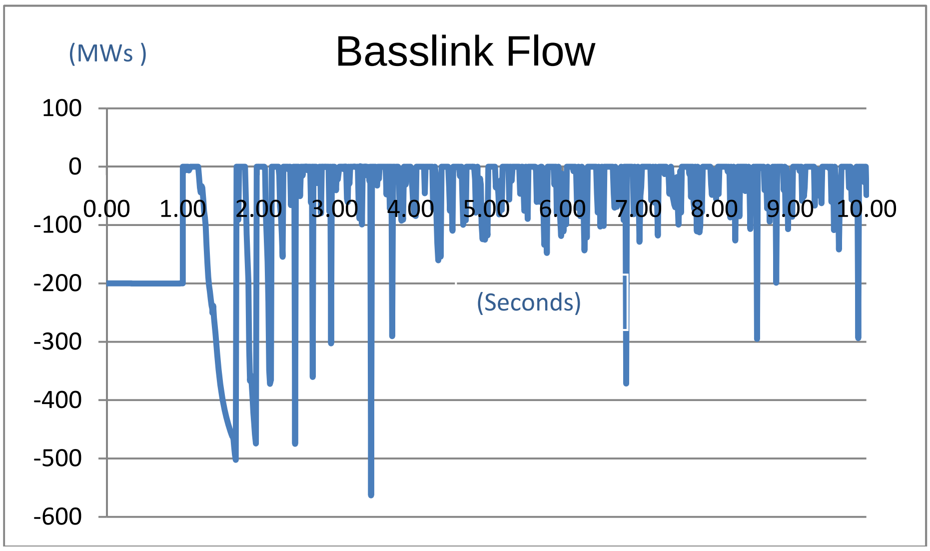


Figure 2: Plot of Basslink response with 500MW wind farm connection

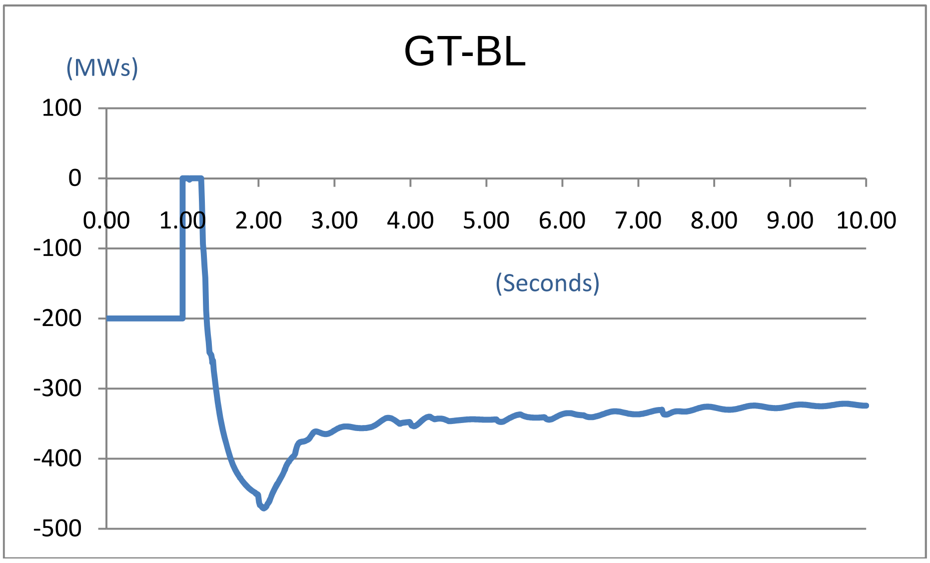


Figure 3: Plot of Basslink response with additional machines connected as synchronous condensers

The issue arises due to the fact that the current Basslink fault level constraint is designed to limit the dispatched flow of Basslink not the possible response of the Basslink frequency controller.

The basic finding of these studies is, that if the power system has sufficient post fault, fault level to sustain Basslink operation in response to variations in system frequency then all other technical requirements (i.e. inertia) will also be satisfied. Noting that this is a limited study, the indication provided is that in the next 3 to 5 years fault level issues at George Town could prove to be more constraining than inertia issues.

The problem observed above also has the potential to manifest itself on any other system bus and reduce the fault level below the minimum needed by quality of power supply requirements. This study has not been comprehensive and further work will be needed to consider potential impacts on the quality of power supply.

The inertia or fast raise/lower services can be provided anywhere on the system. Under scenarios of Basslink export there will be generation on the Tasmanian system providing sufficient system inertia and Tasmania will have access to mainland fast services. Thus under export scenarios for foreseeable asynchronous generation entry, it is unlikely that there will be problems arising from insufficient system inertia. Under scenarios of Basslink import the FCAS constraint has the objective of optimising the import level and required amount of fast services; that is, the fast service costs are minimised by efficiently maintaining the system inertia by limiting Basslink import.

On the other hand, Basslink fault level requirements require generation electrically close to George Town. Thus to support imports local generation that would not otherwise have been dispatched is required to be synchronised in addition to the generation dispatched for energy. This has the effect of increasing system inertia to levels that address the market ancillary service (inertia) constraint thus permitting higher Basslink imports.

7. SYNCHRONOUS GENERATOR SERVICES

As indicated earlier, synchronous generators provided four fundamental services:

- real power (MW)
- reactive power (MVAr)
- inertial energy (MWs)
- fault level (kA)

Other characteristics of synchronous generators are that they also provide synchronising torque and damping torque both of which help to stabilise the power system during disturbances.

The table below lists possible mitigation measures for possible shortages of these services.

Service	Influencing factor	Mitigation
Real Power (MW)	• The size of largest credible contingency • Impact on market ancillary service requirements and frequency control • Impact of WTG fault ride through characteristics • Impact of Basslink frequency controller – fast ramping due to frequency difference under weak system	• Limit the size of the largest contingency • Provide interruptibility services for the difference between the size of the largest generator and the largest permissible contingency • WTG connection in relation to critical faults • Modify response of Basslink frequency controller
Reactive Power (MVAr)	• Loss of very large dynamic reactive power source • Dynamic and static reactive power service • Loss of reactive power source can create local voltage instability or collapse • Impact on Basslink ramping	• Transend and AEMO NCAS and reactive power support program • Limit the size of largest MVAr contingency • Network sources of dynamic reactive support (i.e. SVC, STATCOM)
Inertial Energy (MWs)	• large contribution of the largest generator • displacement of conventional generators by wind turbines • Low value increases market ancillary service requirements	• Critical inertia and critical inertia ratio introduced by AEMO plus additional market ancillary service constraints
Fault Level (GVA)	• Fault level critical to Basslink operation • Loss of large George Town fault current source • Danger of commutation failure – due fast ramping triggered by the frequency controller • Impact on the quality of power supply	• Pre-contingency constraint equation already in place. • Synchronous condensers or generation allocated to Poatina and Mersey Forth generation • Synchronous condenser at George Town • Modify response of Basslink frequency controller • Limit the size of largest fault current injection

Table 2: Services provided by synchronous generators

8. CONCLUSION

Historically the provision of sufficient real power generation (MW) typically ensured sufficient supply of the other services required for secure operation. Power systems have developed on the assumption that these other services will always be there as they are part and parcel of synchronous generation. This is a reasonable assumption for large power systems with a large number of synchronous generators.

It would appear that for small power systems that wish to connect increasing amounts of asynchronous generation the simple dispatch of real power may no longer ensure that there are sufficient amounts of reactive power, system inertia, and system fault level to provide a secure operating state under all likely operating conditions. The issues are amplified in the Tasmanian power system as:

- it is connected to the mainland by a single asynchronous interconnector (Basslink) that has a large capacity when compared with the Tasmanian power system;
- has a single large generating unit; and
- there is no limit to the size of a contingency arising from a network event.

This piece of work was triggered by concerns that low system inertia could become a limiting factor in maintaining a secure operating state as evidenced by apparent shortages of fast raise market ancillary service and corresponding high prices. In addition to driving large requirements for fast market ancillary services low system inertia has adverse consequences for maintaining power system transient and dynamic stability.

In the interim, this problem was significantly reduced when AEMO modified the loss of Basslink market ancillary services export and import constraints. These took into account Tasmanian inertia, demand and Basslink flows and had the effect of establishing minimum system inertia requirements.

Notwithstanding AEMO's market ancillary services constraint, the question remained; are the current mechanisms/processes able to provide sufficient amounts of all four fundamental services to ensure a secure operating state for all realistic operating conditions?

The answer is that AEMO will use all mechanisms available to it to maximise the value of trade within system security constraints. Available mechanisms are both market based and non-market, such as network support services. In addition market participants will respond to commercial incentives. However; there could be changes to the regulatory framework that further increase the value of trade by facilitating the connection of new forms of generation that do not of themselves provide each of the four fundamental services.

For example; the AEMC noted, in their final report on the "Review of Energy Market Frameworks in light of Climate Change Policies", that existing energy market frameworks were sufficient to allow the progression of processes to address inertia. The report further noted that processes were already underway to examine inertia issues in some regions of the NEM, and that these should be allowed to run their course before specific Rule changes were considered. The final report also foreshadowed that AEMO would be coordinating a review of inertia-related issues for South Australia, adding that AEMO was well placed to coordinate such a review as they are likely to involve those parties most knowledgeable of the relevant issues.

The practical implications of the changing nature of the power system (if nothing is done) are that in order to maintain a secure operating state and to avoid increased risk of system collapse:

- there could be periods of time (i.e. during high periods of Basslink import or over night) when the amount of asynchronous generation connected to the power system would have to be limited; and
- restrictions may be required on Basslink imports as it requires a minimum fault level for it to operate reliably.

It is reasonable to assume that as we are operating in a market, the market could solve the issue of scarcity in the supply of market ancillary services, inertia, fault level, and reactive power. For example; the entry of switched ancillary service loads will alleviate the shortage of raise market ancillary services. The issue remains whether a pure market solution can provide the best outcome for Tasmania within the constraint of technological neutrality.

Key considerations are who will take responsibility for managing these issues and how should they be paid for?

If the intention is to actively remove/manage the technical impediments to facilitate the connection of renewable generators and there is a belief that the problem is significant and cannot be managed efficiently by the existing regulatory framework the following options could be considered:

1) Pursue Rules changes to provide additional clarity on AEMO's role in managing these issues.

   AEMO is responsible for system security, so it could be argued that this issue should be left to AEMO to mange using its existing powers. These issues have not yet emerged on the mainland, and the Rules have not been drafted with these types of issues in mind. However, from a Tasmanian perspective will those existing mechanisms provide an optimal outcome?

   It is possible that the current review being undertaken by AEMO of Network Support and Control Ancillary Services (NSCAS) may provide a mechanism for managing these issues.

   Another option would be for the Tasmanian Jurisdiction to manage the issues, and have AEMO perform a reserve trader role in the event that issues aren't managed locally.

2) Put an obligation on the connecting parties to provide these additional services.

   The issue with this approach is that it could lead to a significant disincentive (increased cost) to connecting parties and it may not provide efficient solutions to system wide issues.

3) Require the TNSP to facilitate supply of these services.

   The TNSP is well placed to provide technical solutions to system wide issues. The challenge with this approach is to ensure that the TNSP is suitably incentivised to ensure that any solutions it implements are economically efficient. This would be similar to the approach known as Scale Efficient Network Extensions (SENEs)

4) Modify the market arrangements in Tasmania to ensure provision of these services;

   Trying to set up special market arrangements for Tasmania (i.e. an inertia market or a fault level market) would be extremely difficult and probably impractical to implement and given the small number of potential suppliers it may not provide an efficient solution in any event.

5) Manage issues by constraint equations.

   Due to the technical limitations of constraints equations this option if used without the assistance of some other mechanisms may result in unacceptable constraints on asynchronous generators.

In summary, whilst not recommending a mechanism that enables the connection of asynchronous generation without unduly impacting on the operational flexibility of the Tasmanian power system the following options are proposed for consideration and discussion:

- development of minimum access standards; for example, frequency control capability, minimum inertia, and minimum fault level contribution which could then be enforced through the relevant rules, whether national or Tasmanian;
- the application of Rules clause S5.2.5.12[24] in relation to intra-regional and inter-regional transfer limitations;
- the introduction of new market ancillary services covering inertia and fault level;
- a review of AEMO's Market Ancillary Service Specification (MASS) to provide for inertia contributions;
- a review of the Tasmanian frequency operating standards for network events;
- the development of new non-market ancillary services, network support and control ancillary service of inertia and fault level;
- clarify the provision of network support & control services; and
- the adequacy of constraint equations to manage the issues in this paper.

It is recommended that ETAC make this report available to AEMO and the AEMC, to support further investigations into the impact of a reduction in the availability of services traditionally provided by generators, on system security and market efficiency.

[24] National Electricity Rules clause S5.2.5.12, Impact on Network Capability"

9. DEFINITIONS

AEMO	Australian Energy Market Operator
AETV	Aurora Energy Tamar valley
ETAC	Electricity Technical Advisory Committee
EHV	Extra High Voltage
DC	Direct Current
DFIG	Doubly Feed Induction Generator
FCAS	Frequency Control Ancillary Services
FCSPS	Frequency Control System Protection Scheme
FOS	Frequency Operating Standards
FRT	Fault Ride Through
GCS	Generator Contingency scheme
HVDC	High Voltage Direct Current
IIWG	Inertia Issues Working Group
L6	fast lower service, market ancillary service
NCSPS	Network Control System Protection Scheme
NEMDE	National Electricity Market Dispatch Engine
NER	National Electricity Rules
NEM	National Electricity Market
NSCS	Network Support and Control Services
MW	Mega Watt, 1×10^6 Watts
OFGS	Over Frequency Generator Shedding (Scheme)
PSS	Power System Stabiliser
PSS/E	Power System Simulator for Engineering
R6	fast raise service, market ancillary service
ROCOF	Rate Of Change Of Frequency
SA	South Australia
SENE	Scale Efficient Network Extension
TNSP	Transmission Network Service Provider
TOV	Transient Over Voltage
UFLS	Under Frequency Load Shedding (Scheme)
WTG	Wind Turbine Generator

10. REFERENCES

1) Power System Stability and Control, Prabha Kundur
2) Future wind generation in Tasmania study, Transend Networks, April 2009

APPENDIX 1 SYSTEM INERTIA

The inertia of a body is its tendency to resist change in its motion whether that motion is either spinning or in a straight line. Inertia determines how much energy must be applied to increase the speed of rotation of the object, and conversely, how much energy must be extracted from the object to slow it down. A power system is made up of many generators and motors all spinning at the same relative speed (or frequency) as they are connected together electrically (magnetically coupled) by the transmission and distribution systems. The rotating part of electricity generators or motors exhibit inertia.

The inertia of a machine is determined by its physical characteristics and in particular its rotational speed. Generally, the larger (*moment of inertia – dimensions' and weight*) the rotating object the greater is its inertia.

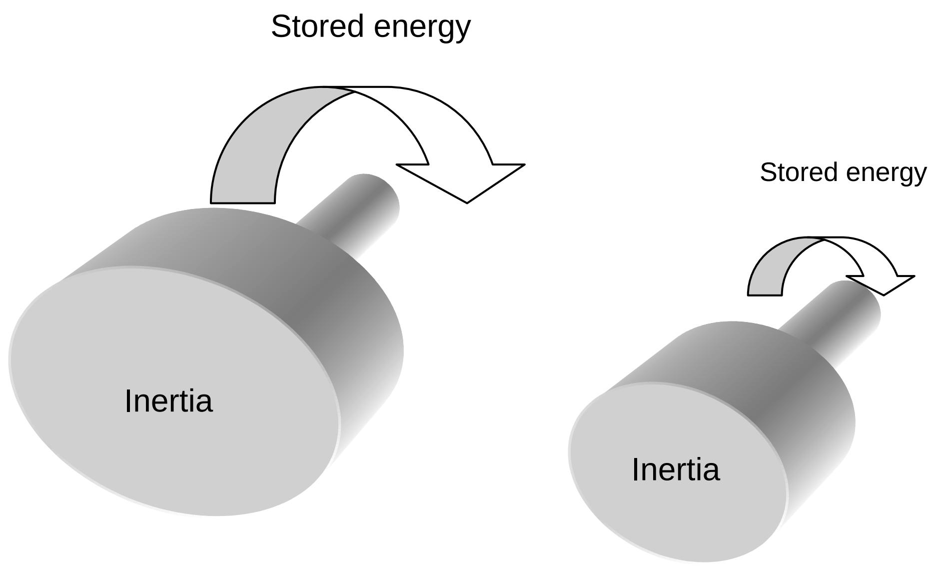


Figure 4: Relative amounts of stored energy in two rotating masses

One of the terms relating to the inertia of electrical machines is the inertia constant H. The inertia constant is the ratio of a machine's stored rotational energy and its rating and is expressed in seconds. For large hydro machines, this constant is around 2.5 to 4 seconds. Hydro turbine/generator are heavy, large in size, but rotate at 166 to 600 revolutions per minute much slower than thermal machines which rotate at 1500 or 3000 revolutions per minute and consequently, their inertia constant is lower.

The inertia time constant represents the time it takes the machine (turbine and generator) to change its speed by 50% under constant (accelerating or decelerating) torque, equal to machine ratings.

An inertia constant of 3 seconds means that the energy stored in the rotating part of a machine could supply its rated load for 3 seconds assuming that the machine is brought to a standstill. For a hydro generator values typically vary between 2 to 4 seconds. The H value for the northern Combined Cycle Gas Turbine (CCGT) is approximately 6 to 7 seconds. The larger the value of H the higher the rotational stored energy of the machine.

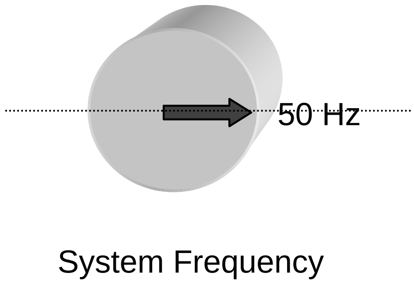
The actual value of rotational stored energy for any generator is given by the following expression:

Stored Energy = H × MVA rating (MW seconds)

The inertia of generators (and whole power systems) is usually expressed in terms of MW seconds.

To extract the stored energy from rotating mass there must be a change of speed (reduction). As the change in frequency following a single contingency is limited to 4%[25] only part of the stored energy will assist system recovery.

In a power system, when generation and load equal each other the system is in balance, generators rotate at a constant speed and the frequency will be stable.



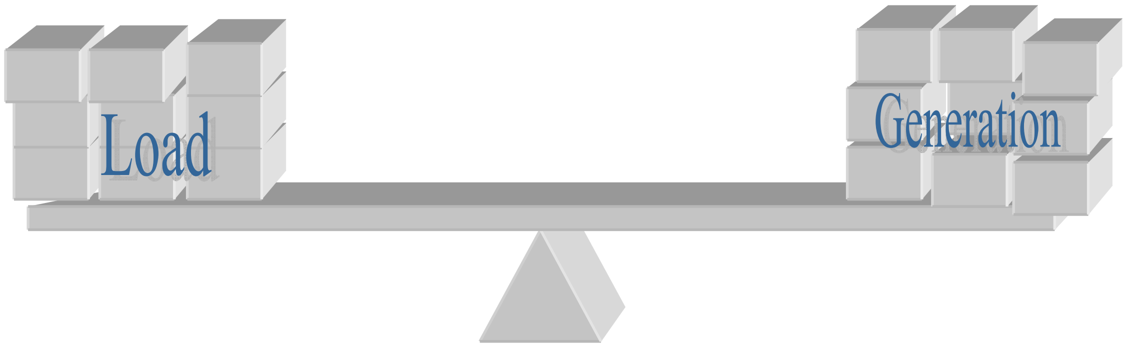


Figure 5: Load and generation balance

If a generator is disconnected from the power system then, in the short term until system reserves react, there will not be enough energy to supply the load, and the system slows down (frequency drops) as energy stored in the spinning machines is used to make up the shortfall. If a power system has a high inertia, it will slow down gradually as large amounts of energy stored in the rotating machines is released. Conversely, if the power system has low inertia it will slow down very quickly as the energy stored in the rotating machines is quickly used up. This is analogous to the slowing down of a car (low inertia) when compared with a truck (high inertia) when the driver takes their foot of the accelerator. The car will slow down much faster than the truck.

[25] Reduction in frequency to 48 Hz is a reduction of 2 Hz which is 4 % of 50 Hz. FCAS should limit the frequency change to 2 Hz

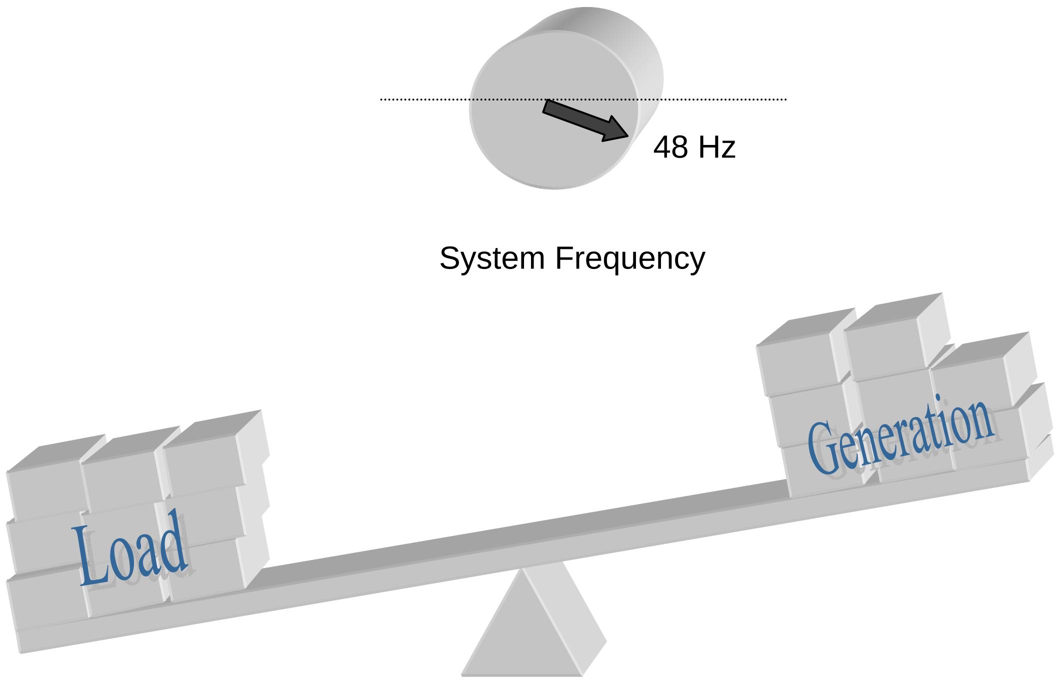


Figure 6: System with load greater than generation

In a similar way, disconnection of a load from the system will cause an excess of energy with subsequent speeding up of the system. A low inertia system will speed up quickly, while a high inertia system will speed up slowly.

Response of heavy (high inertia system) is slow and provides more time for implementation of control and protective actions as well as it allows for time discrimination between different actions. Light systems respond much faster, in the case of small disturbances allows for good control however large disturbances can easily destabilise such systems.

A power system will quickly become unstable and collapse if it speeds up or slows down in an uncontrolled manner. So Frequency Control Ancillary Services (FCAS) are used to control the frequency of the system. Loads and generators control their injection or absorption of power from the system in response to changes in frequency, so restoring the balance between generation and load.

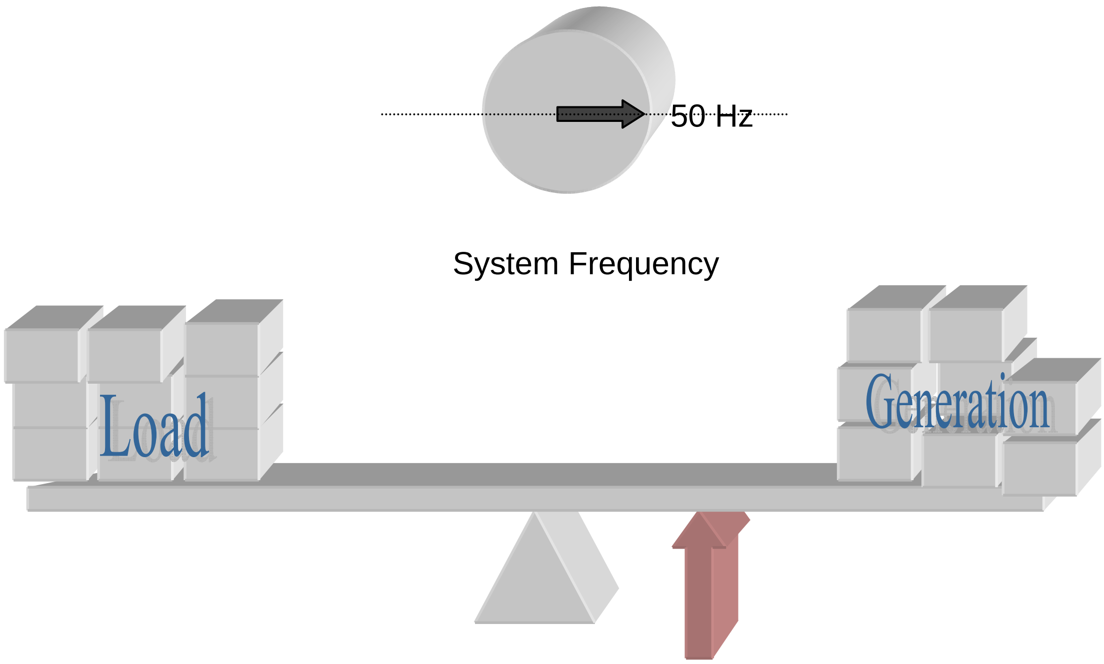


Figure 7: Load and generation balance and the action of FC ring balance

Traditional generators driven at constant speed by governed hydro or thermal turbines are directly coupled to the power system and can't help but provide "inertial response".

If the frequency drops, their inherent resistance to change in rotational speed results in power transfer from the machine to the grid increasing, so slowing down the decline in frequency. Similarly, if the frequency increases, the power transfer to the grid decreases, so slowing the increase in frequency.

Continuing the vehicle analogy, stopping a truck in the same distance as a car requires the truck to have much greater capacity braking systems. The truck has greater inherent resistance to changes in its speed.

Traditional generation can be run efficiently at fixed speed due to control over the input energy source (i.e. gas, water or steam). Wind generation, on the other had, has no control (very slow control – pitch angle control) over input energy, and seeks to maximise aerodynamic efficiency by controlling the speed of the generator independently of grid frequency. As such; wind generators use a variety of different generator technologies ranging from standard induction motors to AC/DC/AC power electronic controllers.

Wind generation can not directly couple synchronous generator as the applying variable input torque produced by the wind to the fixed system frequency of 50 Hz would place unacceptable stresses on the gear box. Consequently shock absorbers in terms of induction generator with 2% slip or variable speed generators allowing for wide slip variations have been introduced.

Variable speed generation allows wind turbines to operate at maximum efficiency and hence makes better use of the available wind resource.

Wind turbines using induction generators are sensitive to frequency and provide inertial response in a similar manner to traditional generation. Variable speed machines with a wider range of operating speeds such as "full converter" and "double fed induction" generators use power electronics to maintain optimum power output independent of grid frequency.

As such they are insensitive to grid frequency and provide no inertia response unless the control systems are programmed to do so, that is they have an H equal to 0 seconds.

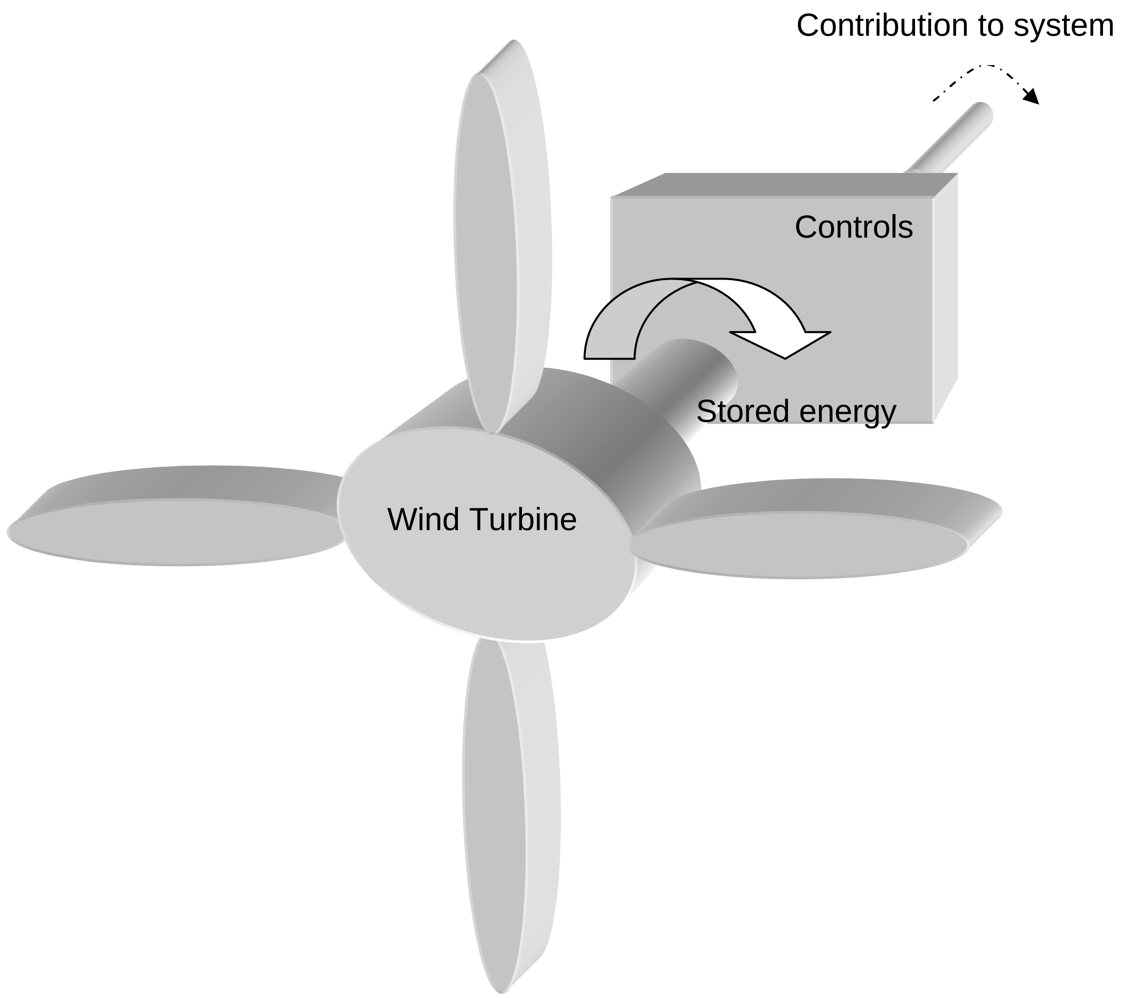


Figure 8: Contribution to system inertia by some wind turbine technologies

Variable speed wind turbines currently offered in the Australian and international markets are not configured to provide inertial response. There are no fundamental reasons why these turbines can't provide inertial response, as the forces on the turbine that would result from providing these services would be low relative to those experienced under an emergency stop or fault ride through conditions. Rather, the absence of this capability is a reflection of in-sufficient global demand for this feature to justify R&D effort in development of the capability.

It is likely that this situation will change over the next five years, with high wind penetration levels in number of major power systems around the world making inertial response from variable speed wind turbines economically attractive. It is considered likely that that all major turbine manufactures are now considering developing this feature to some degree, and General Electric has publicly announced such efforts.

In the Tasmanian context, the combination of excellent wind resource, small system size, DC coupling to the mainland and predominance of relatively low inertia hydro-electric generation create the potential for conditions of very low power system inertia.

Similarly, the introduction of other technologies such as solar voltaic and fuel cells have the potential to impact adversely on system inertia. Although wind generation does not reduce the power system inertia per se, market outcomes that result in changes to the make up of the generators dispatched has the potential to result in unprecedented low levels of system inertia. In the absence of other initiatives, such low levels of inertia will result in increased FCAS requirements and potentially reduce inter-regional transfer limits.

The issue for Tasmania is that if the system inertia was to become too low the existing market arrangements and process may not result in a secure power system, that is to say that the probability of a single event causing wide spread disruption could be significantly increased.

APPENDIX 2 SYNCHRONOUS GENERATORS

Traditionally large scale generation of electricity has been achieved by using synchronous generators (i.e. large thermal plant and hydro electric generators). The way that these generators work is to supply energy into the rotor (by steam or water) and this energy is then transferred into the power system via the magnetic field (flux paths) into the stator which is directly connected to the power system. Refer Figure 6 below

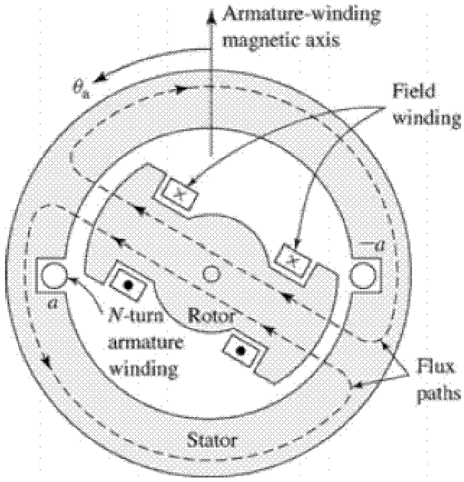


Figure 9: Simplified traditional synchronous generator

What this means is that every synchronous generator on a power system is directly connected (via the magnetic field) to every other synchronous generator. It also means that all generators on the power system "see" faults on the power system and assist the power system in riding through those faults. The bigger a power system, the more synchronous generators will be connected and the less likely it is that a single fault will cause serious disruption to the power system.

One conceptual way to think about this issue is to consider that the more magnets you have the stronger will be the magnetic field and the harder it will be to pull away a single magnet. If a big system with lots of magnets gets bumped it has a strong magnetic field and it is less likely to be disturbed unless it is a really big jolt Conversely the fewer magnets you have the easier it will be to pull away a single magnet. If a small system gets bumped it is much easier for the system to be disturbed and as the magnets are removed the easier it becomes to disturb the system.