TasNetworks
Delivering your power

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5 December 2017

Australian Energy Market Commission (AEMC)
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce,

RE: EPR0059 - Frequency Control Frameworks Review

Tasmanian Networks Pty Ltd (TasNetworks) is pleased to provide our response to the *Issues Paper – Frequency Control Frameworks Review* which was published by the AEMC on 7 November 2017.

As the Transmission Network Service Provider (TNSP) and Distribution Network Service Provider (DNSP) in Tasmania, TasNetworks is focused on delivering safe and reliable electricity network services while achieving the lowest sustainable prices for Tasmanian customers. We are committed to ensuring the secure operation of the Tasmanian power system while seeking new and innovative ways to extend the capability of our networks. This includes pursuing solutions that will support an increased penetration of intermittent renewable generation in Tasmania.

We contributed to the development of, and fully support, the Energy Networks Australia submission. The purpose of this submission is to highlight key issues that have particular relevance in the Tasmanian region as well as provide commentary on a number of technical matters pertaining to network frequency control. Given the nature of the Tasmanian power system, frequency control has always been a significant consideration for the design and operation of our network. It has dictated the need for differing Frequency Operating Standards (FOS) and the development of innovative solutions, including the implementation of fast acting System Protection Schemes (SPS) and rate-of-change-of-frequency (ROCOF) dispatch constraints, well-ahead of similar needs surfacing in other National Electricity Market (NEM) jurisdictions. Looking forward, these challenges will only intensify and will likely drive the need for novel changes including the formal introduction of new frequency control services (in particular Fast Frequency Response (FFR)) and thus we fully support a review of how such services can be coordinated and co-optimised with other system security functions including the provision of inertia.

Tasmania is best positioned to test these innovative frequency control frameworks, especially FFR services. A trial project in Tasmania provides an opportunity to explore options in detail and examine how FFR could be operationalised (dispatched) in conjunction with traditional frequency control services. We welcome the opportunity to provide more information on a proposed trial as part of the AEMC's consultation process for the Frequency Control Frameworks Review.

These technical innovations will require changes to regulatory frameworks. TasNetworks believes that any regulatory solutions contemplated should take into account existing off-market and unregulated control schemes. These are particularly relevant in Tasmania where system stability is already managed through a number of SPS and generator contingency schemes (GCS).

We understand the aspiration that regulatory measures should not be developed to deal with issues in a specific region. However, we are concerned that this approach could exclude solutions that can be implemented in Tasmania, due to the nature and willingness of major participants in our region, which are not relevant in other parts of the NEM. While TasNetworks does not suggest that these local opportunities should be mandated in a national scheme, we believe that the National Electricity Objective (NEO) would be best served by ensuring that national regulatory measures don’t prevent or inhibit innovative local or jurisdictional solutions.

TasNetworks is supportive of any changes that help customers realise the full potential of their distributed energy resources (DER). With the increasing connection of DER it is important to establish a clear framework for connection of DER that enables secure, reliable and safe supply for the long term benefit of consumers.

We look forward to further discussions with the AEMC on the matters outlined in this submission. Should you have any questions in relation to our submission, these should be directed to Tim Astley on (03) 6271 6151 or via email to Tim.Astley@tasnetworks.com.au.

Yours sincerely,

Tim Astley

NEM Strategy and Compliance Team Leader

1. The Tasmanian context

Tasmania currently has 308 MW of wind generation in service along with approximately 109 MW of embedded solar photovoltaics (PV). Current connection applications (in excess of 1000 MW) would see the amount of wind generation residing in Tasmania more than double in the next two to three years.

It is therefore credible in the foreseeable future that Tasmania could be supplied from predominantly asynchronous generation for significant periods of time, supported only by minimum levels of synchronous machine support to manage various power system security issues. As a practical example of TasNetworks' existing operating environment in regards to asynchronous generation, Tasmania has so far recorded a peak instantaneous non-synchronous penetration ratio of 78.9%, which was set in the early hours of 20 March 2015. This consisted of 467 MW of Basslink import and 291 MW of wind generation, supplying a system load of 960 MW. The Tasmania system operated continuously above 70% of non-synchronous penetration for nearly 7 hours on the same morning. The effort was repeated again on 2 February 2017 with operation above 70% for 5 hours. New generation patterns will emerge that are expected to require the dispatch of synchronous condensers, as well as a small number of hydro generators operating at low power outputs to maintain a secure system.

Frequency control in Tasmania has traditionally been more challenging than for the interconnected mainland network. The dimension of credible generator and load contingencies are significant compared to the overall system size and the response characteristics of hydro generators generally preclude the delivery of substantial fast FCAS[1], especially raise service. When coupled with increased generation intermittency, longer periods of sustained low inertia operation and a general lack of surplus fast raise and lower capabilities can make frequency control in Tasmania problematic. It is also worthy to note that frequency control issues are likely to coincide with challenges involving system strength as well as network voltage control, the latter being due to the remote location of many of the proposed wind developments.

For these reasons, TasNetworks is actively investigating ways to bolster various aspects of network security, including increased utilisation of demand response mechanisms and other new technical innovations. We believe there is justification in considering new technologies that are capable of providing complementary, multi-faceted dynamic response characteristics that service both frequency and voltage control from a common platform. Any credible option that delivers demonstrable cost and system security benefits for end consumers should be considered. .

To this end, TasNetworks would like to specifically highlight our contributions to Questions 15, 16 and 17 as presented by the AEMC in its *Issues Paper*. We believe that Tasmania can offer a valuable trial site for a new fast frequency response (FFR) technology which is likely to have application across other mainland regions of the National Electricity Market (NEM) over time.

Responses have also been provided to a number of other questions and are based on TasNetworks' experience with managing frequency control issues in Tasmania as well as our participation in various reviews and consultations discussing industry reforms, particularly in relation to future management of distributed energy resources (DER).

[1] FCAS: Frequency Control Ancillary Service

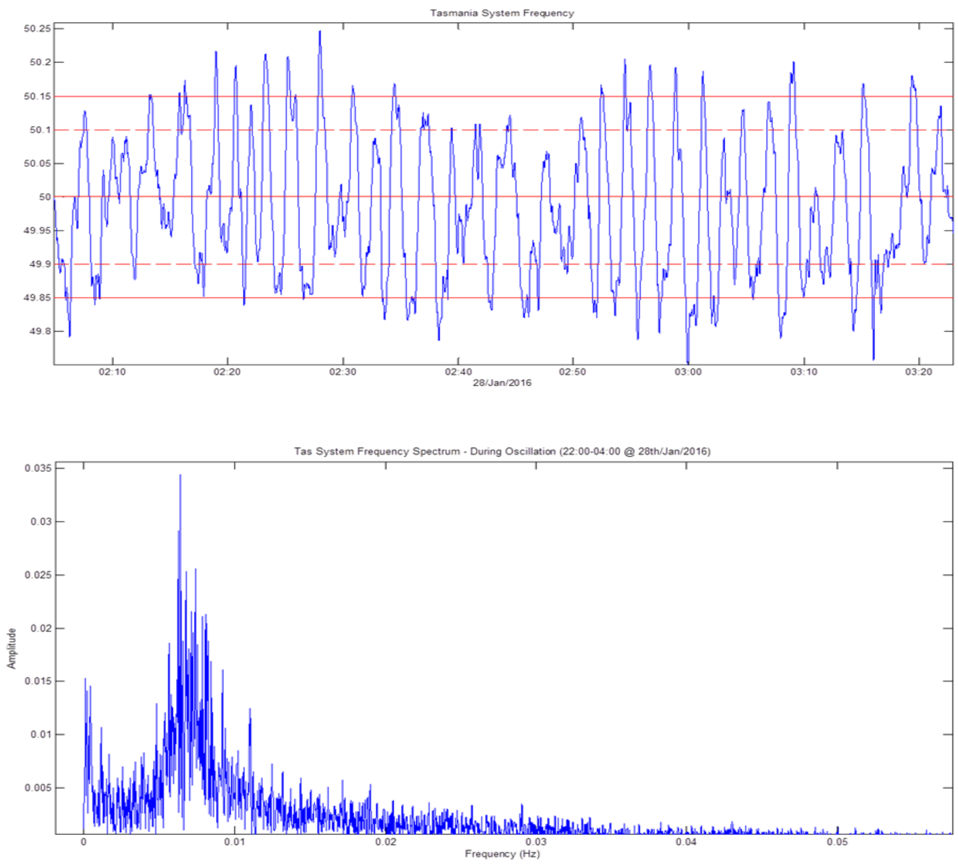
2. Detailed responses to questions raised by the AEMC

Question 8 Risks associated with a flattened frequency distribution

TasNetworks would suggest that the 'shape' of the frequency distribution profile is probably not the key issue (given the design of plant and equipment to accommodate operation anywhere within the *normal operating frequency band*), but it is rather the 'stability' of network frequency that is more important.

To illustrate the potential issue, a 90 minute snapshot of system frequency taken on 28 January 2016 (shown below) demonstrates a very obvious oscillatory characteristic. An analysis of the frequency components of the signal highlights a dominant mode of approximately 0.006 to 0.007 Hz (between 2 and 3 minutes). The period of measurement was during the extended Basslink outage and is presented here for illustrative purposes only.

Figure 1: Oscillatory frequency characteristics in the NEM (Tasmanian region)



While a measured frequency with this sort of underlying variability may still satisfy the basic requirements of the FOS (99% of the time between 49.85 and 50.15 Hz), it should **not** be classified as acceptable given the continuous oscillation that is present. Such frequency deviations will induce a continuous response from governor control systems having a small enough dead band, causing mechanical systems to be cycled and thus contribute to significant 'wear and tear' on plant and equipment. Modern energy storage systems fitted with frequency control capability may also be negatively affected from the continuous charge/discharge cycle, potentially limiting their ability to have small dead bands applied (to avoid premature ageing of the storage medium for instance).

When considering what is 'acceptable' and what is not, TasNetworks would recommend a more holistic assessment of frequency performance beyond a pure statistical analysis. Sustained periods of oscillation[2] should be categorised in a manner that encourages investigation and intervention (where necessary). As with many control system designs, this could be done by considering oscillation frequency, magnitude and damping characteristics, noting that the latter may be challenging to assess.

<u>Question 10/12</u> **<u>Mandatory primary frequency control and market based options</u>**

TasNetworks has a preference for mandating the requirement for generators to provide primary frequency control in real time for the reasons already highlighted by the AEMC in its *Issues Paper* and we offer the following points in support of this preference:

a) By mandating the requirement that a broad distribution of frequency control capability should exist, which when required, is less likely to result in significant changes in point to point power flows beyond what is already anticipated across a given dispatch interval (due to market outcomes and the response of AEMO's central dispatch process). This can affect actual versus anticipated contingency sizes depending on network topology and thus have a feedback effect on power system security.

b) Distributed capability also provides benefits following multiple contingency events where the exact configuration of the post-event network may be difficult to fully anticipate. Local control actions that inherently 'do the right thing' can act to stabilise the immediate area and may allow for faster network restoration.

c) Control of frequency is a fundamental requirement for the operation of a synchronous power system. While providers should reasonably expect to be financially compensated for any costs incurred in delivering such a service, is it reasonable to have the option to *not* provide what is 'essential', especially in circumstances where there are no technical limitations preventing it?

In our response to the AEMC Consultation Paper "*Generator Technical Performance Standards Rule Change 2017*", we have stated that all new *generating systems* of significant enough size should be made *capable* of providing a frequency control response where the technology and physical attributes of the plant do not present a limitation. The commentary offered above effectively extends our existing viewpoint.

TasNetworks would like to provide comments on a number of related issues that are considered to 'best fit' under this Question 10 but also overlap into Question 12.

TasNetworks is of the view that frequency regulation within the *normal operating frequency band* should be provided by governor control systems fitted to individual *generating units*. Going forward, this should include 'park level control schemes' that can provide near equivalent services from solar

[2] Oscillations in this context may be anything up to a cycle time of several minutes as shown above.

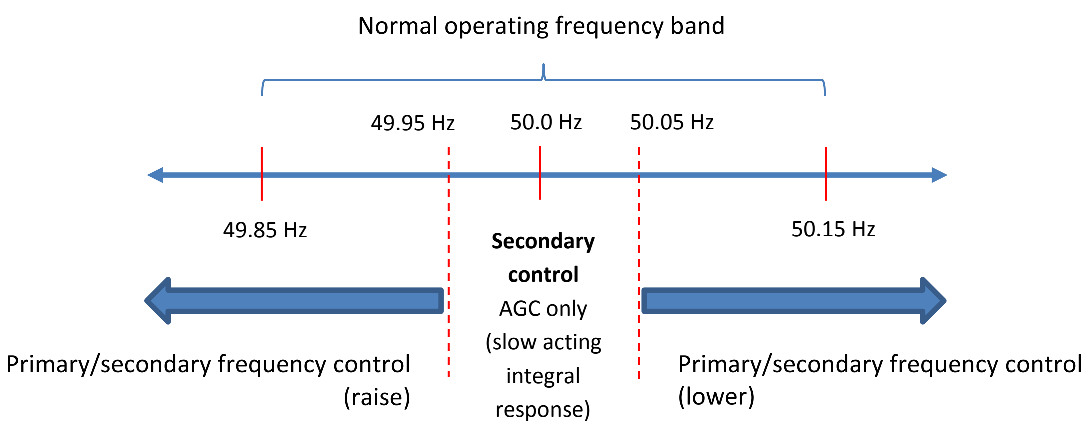
and wind *generating systems* (albeit asymmetrical unless deliberately constrained to provide headroom in the upper direction).

TasNetworks is not supportive of the concept that frequency regulation within the *normal operating frequency band* is the sole domain of centralised automatic generation control (AGC). AGC is best suited to slower 're-dispatch' of *generating units/systems* to maintain a desired 'average' set point and to provide time error control. The average set point is determined by economic or network security criteria and can be time varying to allow for ramping between different levels of steady state output.

In TasNetworks' view, attempting to regulate frequency within the *normal operating frequency band* using only AGC is not appropriate. We believe that governor dead bands should be reduced such that broadly distributed primary frequency control capability is a significant contributor towards normal frequency regulation. With careful selection of dead band limits, an operating band can be created for AGC to perform time error control independent of governor action (if this continues to be a requirement[3]). There is no reason why appropriate coordination of governing capability and centralised AGC response cannot satisfy the existing Frequency Operating Standards (FOS).

A potential model for consideration is offered in Figure 2.

Figure 2: Management of frequency regulation



In Section 5.2.4 of the Issues Paper, there are similar discussions presented however TasNetworks is concerned about the apparent need (desire) to separate regulation and contingency FCAS. Whether these descriptors best serve the NEM going forward is a question for consideration. The following comments are offered for discussion:

a) TasNetworks does not believe there is any justification for changing the FOS, i.e. reducing the size of the *normal operating frequency band*. In TasNetworks opinion, this is effectively allowing market design to dictate physics, whereas the reverse philosophy should be applied.

[3] The Reliability Panel is looking at the potential removal of the accumulated time error limit from the Frequency Operating Standard (FOS) through the course of stage two of the FOS review.

b) Going forward, are the required frequency control services better described as follows:

   i. **Primary frequency control**, incorporating:

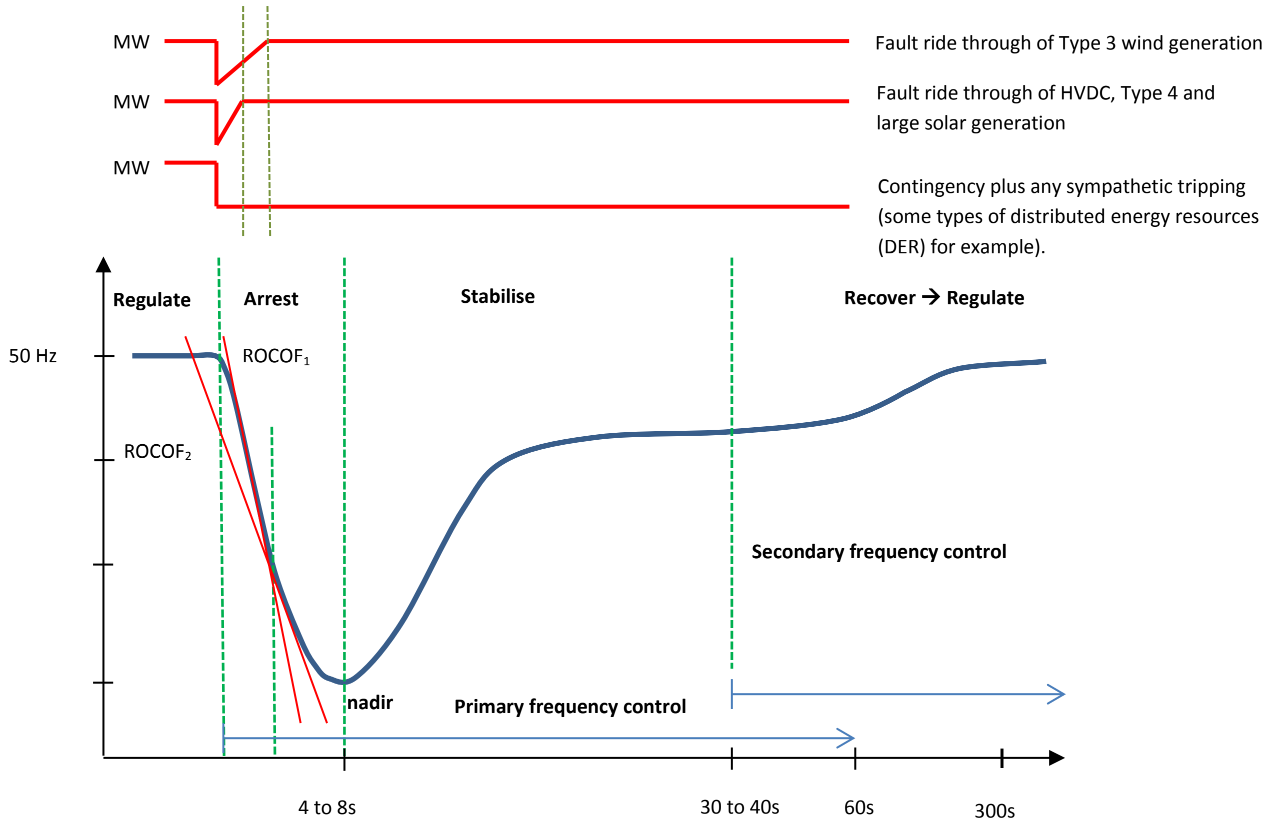
      - **Fast Frequency Response (FFR)** capabilities, 200 ms to 2 s response time frame, primarily for contingency support, provided by a range of emerging technologies including energy storage and demand side response to assist in the management of rate of change of frequency (ROCOF) and the efficient delivery of fast governor responses.
      - **Fast governor response** outside of ±0.05 Hz dead band, up to a 6 second response timeframe, having the duel functions of providing frequency regulation (to manage normal operation of the power system) as well as contingency support (arrest frequency within the defined FOS limits).
      - **Slow governor response** outside of ±0.05 Hz dead band, up to 60 second response time frame, having the duel functions of providing frequency regulation as well as contingency support (stabilisation of frequency onto the average droop characteristic of the power system).

   ii. **Secondary frequency control,** incorporating:

      - **Sustained governor response** outside of ±0.05 Hz dead band, up to 5 minute response time frame, having the duel functions of providing frequency regulation as well as contingency support (maintaining frequency near to the average droop characteristic of the power system while AGC re-dispatches energy surplus or deficit that has resulted from the contingency event).
      - **AGC response,** most likely continuous in nature but based on slow acting integral control only (or with very limited proportional response) that acts to restore system frequency back to 50 Hz operation in a time frame of 'many tens of seconds'.

These concepts can be directly equated to the most important response characteristics of the power system that need to be managed now and into the future, including the fault ride through performance of power electronic interfaced generation equipment.

Figure 3: Application of frequency control framework in reality.



The relevance of the two ROCOF periods shown in Figure 3 will be discussed as part of subsequent questions.

c) In this particular model, the focus of the frequency control framework is dynamic response capability rather than whether the frequency deviation is caused by a 'regulation' or 'contingency' event, i.e. any movement of frequency away from 50 Hz ultimately needs to be corrected and it can be strongly argued that the same mix of capabilities are required to enable this to occur irrespective of the 'cause'.

TasNetworks suggests that there is an opportunity to develop an alternate FCAS market framework based on five sub-categories that is largely based on existing platforms but introduces FFR as an additional feature. We believe the model outlined above creates better linkages to the natural physics of the power system and therefore increases its relevance and acceptance (thus creating a positive feedback effect on parallel issues like the current review of generator technical performance standards).

In addition to discussions about mandating certain generator capabilities, TasNetworks believes that this issue should be expanded to include consideration of future high voltage direct current (HVDC) interconnectors that may be developed across the NEM. The ability of such interconnectors to transfer FCAS and thus share the 'frequency control resources' that exist in each region will be an important aspect of future power system operations.

An example of this is the ability of the Basslink HVDC interconnector between Tasmania and Victoria to transfer FCAS via its frequency control functions. Such capability does not exist on other HVDC installations in Australia[4]. More recent developments in HVDC technology now include 'phase angle control' which allows a HVDC interconnector running in parallel with AC transmission to alter its power flow based on measured voltage angles at either end. This allows the DC transmission path to automatically 'share' changes in power flow as if it were AC.

TasNetworks considers it important that future HVDC interconnectors be equipped with frequency (or other appropriate power flow control) capabilities that ultimately complement the prevailing frequency control framework. Given advancements in technology, there seems little reason not to mandate the provision of such capability.

<u>Question 14</u> **<u>Frequency monitoring and reporting</u>**

As TasNetworks has previously suggested that reporting by AEMO be maintained, we would like to contribute to the discussion by offering the following as useful metrics:

a) Statistical analysis (histogram) of frequency (essentially the ongoing population of the data sets as shown in Figure 3.4 and 3.5 of the *Issues Paper*).

b) Time error trends over the reporting period. Analysis of such data as a time series provides a useful mechanism to identify significant periods of sustained under or over frequency.

c) The number of excursions outside of the *normal operating frequency excursion* band in the reporting period. Recognising that this is not overly meaningful for the Tasmanian region (given our frequency control characteristics), the number of excursions below and above 49.0 Hz and 50.75 Hz respectively is an appropriate alternative. These are considered to be the practical limits for 'routine events', mainly associated with Basslink reversals. Frequency measurements outside of this range generally indicate larger scale network events.

d) Fast Fourier transform (FFT) analysis performed on an appropriate range of data (daily or weekly?). The results of each FFT would be equivalent to that shown in Figure 1 (above) and are likely to be useful in identifying periods of oscillatory behaviour when overlaid as a 'family of curves'. Creating signatures of this type would also provide useful information to assess the impacts on any changes (such as to AGC settings) that may be applied over time.

TasNetworks would suggest that a reporting period of quarterly unless AEMO is able to automate analysis (and documentation) to produce monthly reports without excessive effort.

In terms of perceived benefits, TasNetworks offers the following:

a) "One accurate measurement is worth a thousand expert opinions" – Rear Admiral Grace M. Hopper, United States Navy

b) "What gets measured gets managed" – Peter Drucker, Management Consultant

Reporting on measurement is just as important as taking the measurement itself.

[4] That TasNetworks is aware of.

Question 15 Defining FFR

TasNetworks has reviewed the AEMO document "*Fast Frequency Response in the NEM – Working Paper*" and offers the following contributions to both AEMO and the AEMC on the future role of FFR in the Tasmanian region (with likely application across the NEM as the generation fleet continues to transition away from a dominance of large synchronous machines).

Relationship between *primary frequency response* and *primary frequency control*

The *primary frequency response* of the power system will be dictated by:

a) Contingency size.

b) Any fault ride through (FRT) response of power electronic interfaced generation and HVDC interconnections. Withdrawal of active power for even 'a few hundred milliseconds' contributes significantly to the initial ROCOF (shown as $ROCOF_1$ in Figure 3) and the eventual depth of the frequency nadir.

c) The response of distributed energy sources (DER) which may include FRT and/or sympathetic tripping depending on the presence of a fault, its location and the resulting impact on the surrounding network voltage profile.

d) Load response characteristics to both the voltage and frequency excursion.

e) System inertia.

The *primary frequency response* is largely dictated by the physics of the power system and the equipment connected to it. In the time frame of a fault appearing, being cleared by protection systems and voltage recovering (say 150 to 200 milliseconds) there is very little control action that is possible given the need to measure, determine an appropriate response, and then deliver it. The risks to the power system during this initial period include undesirable operation of protection systems which utilise ROCOF[5] including anti-islanding protection, loss of synchronism (either specific generating units, sub-sections of the network or entire regions[6]) and severely depressed voltages due to the instantaneous redistribution of power flows through the network to compensate for both the outage event as well as FRT responses (delivered by inertial responses coming from synchronous generators).

In terms of managing ROCOF (and to some extent, transient stability) the two variables that can be deliberately managed during real time operation are system inertia and contingency size. It follows that in a synchronous power system, a minimum amount of synchronous inertia will always be required to help manage the *primary frequency response* of the power system, which in effect is a subset of the broader power system stability phenomena.

[5] Also referred to as df/dt in the case of some protection systems.
[6] As was the case with the South Australian blackout.

Having 'survived' the first couple of hundred milliseconds, certain elements of the *primary frequency control* portfolio come into play. The following are important issues to recognise:

a) Active power recovery following an FRT event can take anywhere between (say) 300 milliseconds and a second after voltage recovery depending on the type of equipment. HVDC and Type 4 wind turbines[7] can generally recover faster, whereas Type 3 turbines tend to be slower. The 'energy deficit' contributions shown at the top of Figure 3 continue to impact ROCOF until generation / power transfer is fully restored.

b) The response of governor control systems on thermal generating units will have started to move in this time frame but given the eventual need to control mechanical systems like fuel and steam valves (even if the control systems are fully digital), there will be inherent delays in providing meaningful levels of frequency support.

c) In the first second after the commencement of a frequency event, hydro generating units will offer nothing effective and are more likely to contribute to the frequency excursion due to their hydraulic response characteristics (as the governor systems begin to open or close).

d) System inertia continues to be a critical variable in managing the maximum ROCOF during the period of time out to say one to two seconds post contingency.

These first few hundred milliseconds is <u>where FFR can make a substantial difference</u> to the dynamic performance of the power system.

a) FFR can be used to *complement* whatever level of system inertia is required to manage power system stability during and immediately post fault.

b) In doing so, FFR can reduce the 'sustained' ROCOF (shown as $ROCOF_2$ in Figure 3) so that more time is available to provide fast governor response before the minimum frequency stipulated by the FOS is reached. A by-product is to reduce the amount of fast raise governor response that is necessary, thereby increasing the efficiency in how it can be delivered[8].

c) A transient energy injection from an FFR source, even lasting for only six to eight seconds, can help fill the energy gap created by multiple devices entering FRT mode, as well as compensate for the initial 'reverse' response of hydro governor units.

[7] Type 4 wind turbines use fully rated power converters to interface each generating unit to the power system. Type 3 wind turbines are also known as doubly fed induction generators (DFIG).

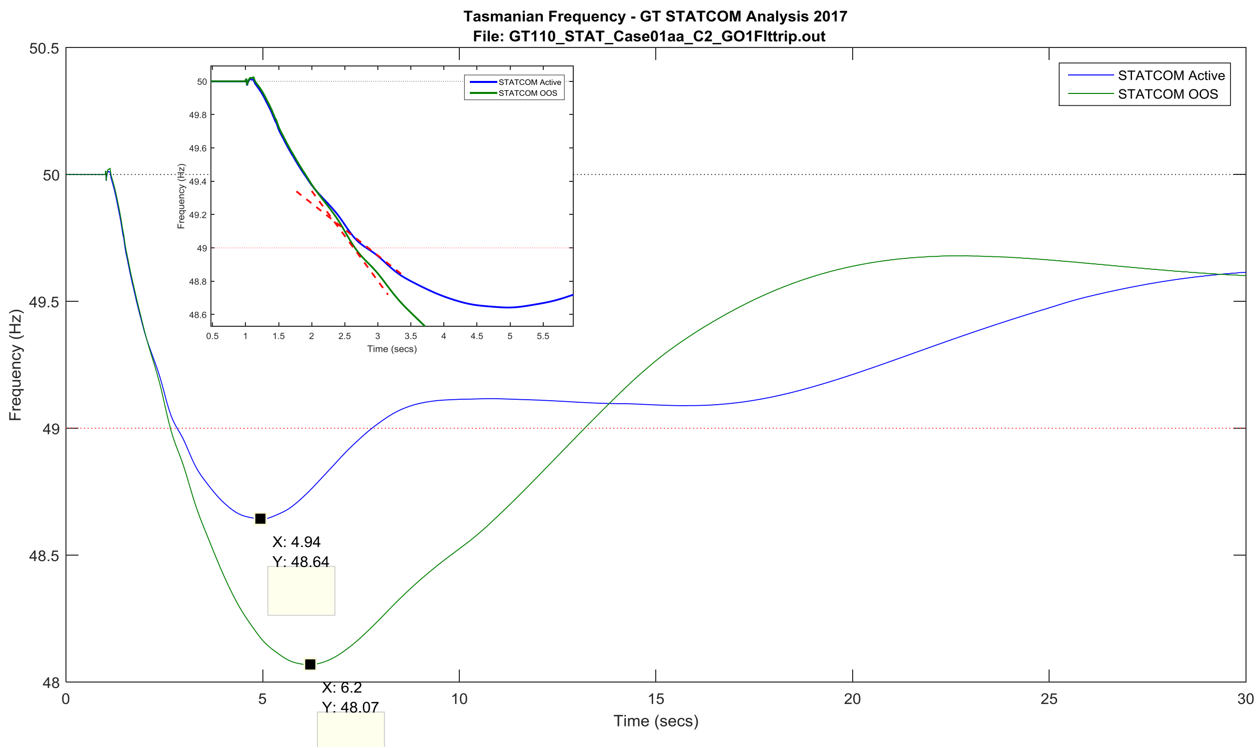
[8] In the Tasmanian context, this equates to not requiring hydro generating units to operate at low power outputs simply to provide fast raise reserves. Low power operation is hydraulically inefficient and can contribute to increased wear and tear.

A simulated example of these characteristics coming into play within the Tasmanian power system is provided in Figure 4. This is not an extreme scenario and is presented here purely for demonstration purposes. The FFR source in this case is a Siemens SVC Plus FS unit installed at George Town substation in the state's north. The energy storage medium is based on super capacitors which can deliver up to 50 MW of power injection lasting for up to 8 seconds, equating to 400 MW.s of energy. It can be noted that:

a) The minimum frequency is increased from 48.07 Hz (indicating the dispatch of 'just enough' fast raise FCAS to meet the FOS) to 48.64 Hz. This would in effect allow some of the fast raise FCAS being provided from 'inefficient sources' to be removed from service while still enabling the FOS to be satisfied.

b) The ROCOF measured at 49.0 Hz decreases from 0.54 Hz/s to 0.31 Hz/s. This particular frequency level is a critical breakpoint for the Tasmanian power system due to the design of the Under Frequency Load Shedding (UFLS) Scheme. One of the criteria for determining the minimum amount of inertia required to be dispatched in Tasmania is ensuring that the ROCOF at 49.0 Hz is below 1.18 Hz/s to prevent activation of the UFLS for credible contingency events. It can be seen that the FFR response is effective in helping control ROCOF at this point in time (noting that the initial slope is still largely dominated by system inertia).

Figure 4: Example of FFR contribution to frequency control in Tasmania



Discussions above have concentrated on the provision of raise reserves however similar principles apply for the provision of lower services. As fast lower FCAS tends to be more readily available in various forms, the control of over frequency events has not been as challenging (to date). This is not to say that future operating scenarios won't eventuate where such challenges present themselves.

Having now set the scene, TasNetworks views on FFR are as follows:

a) Access to appropriate FFR sources can benefit the power system now, certainly in Tasmania.

b) The importance of FFR will continue to increase as more power electronic interfaced generation is connected, increasing the network's exposure to low inertia operating periods and increasing 'average' FCAS raise requirements in the process. Based on existing connection applications (as outlined in Section 1), significantly increased frequency control challenges are imminent rather than being 'a decade away'.

c) There is a need to consider the required balance between FFR sourced from 'switching controllers' and continuous control devices. As highlighted by TasNetworks in its submission to the *2017 Frequency Standards Review*, continuous control devices are capable of automatically compensating for the exact needs of the power system, whereas switching controllers generally provide 'block changes' in load or generation. The latter does not necessarily match the imbalance created by a given contingency event.

d) TasNetworks, in conjunction with Hydro Tasmania, is preparing to commission an Adaptive Under Frequency Load Shedding (AUFLS) scheme to increase the availability of fast raise FCAS in Tasmania. The justifications for doing so are as discussed above. The AUFLS scheme is unregulated and a scheme which relies on demand response. It will bid into the market the equivalent FCAS that is provided by contracted loads, thereby reducing the demands placed on its generation portfolio. To address the issues outlined in point (c) above, TasNetworks has set a limit which requires 35 MW of fast raise to continue to be provided by 'continuous acting controllers' which can include governing responses as well as Basslink[9]. TasNetworks has provided the SCADA platform on which to implement the AUFLS control scheme.

e) Various technologies are becoming available to meet FFR needs. As further evidence in addition to that documented in the *Issues Paper*, TasNetworks is currently investigating a project with Siemens to trial a new innovation that combines the traditional reactive power capability of a STATCOM[10] with energy storage in the form of super capacitors. The resulting device is capable of dynamically controlling active and reactive power to provide a combination of FFR and transient voltage control. The multi-faceted capability of such a device makes for an efficient network investment when both voltage and frequency control components are needed.

   The proposal has been presented to both AEMO and ARENA. TasNetworks believes it would be an ideal proof-of-concept project for investigating both technical, market and regulatory issues associated with future integration of FFR services into the NEM. To this end, TasNetworks encourages the AEMC to consider the opportunity and is prepared to provide a more complete briefing on the project if requested.

[9] Noting that any raise services which can be provided by Basslink into the Tasmanian region during import conditions (flow from Victoria to Tasmania) are presently ignored due to a contingency reclassification which has been imposed by AEMO. The associated issues remain unresolved to date. Refer AEMO Market Notice No. 47360 and No. 47855 for details.

[10] STATCOM – Static Synchronous Compensator, forming part of the Flexible AC Transmission System family of devices.

Question 16 Potential options for making changes to the FCAS frameworks

Building on the discussions already presented in Questions 10 and 15, TasNetworks would like to raise the following issues for consideration.

a) On the basis that various energy storage mechanisms are now available and in the case of the potential project being undertaken with Siemens mentioned above, fully integrated as part of a 'traditional' reactive power control device, what the appropriate market / regulatory approach that would allow Network Service Providers (NSPs) to provide frequency control services could be trialled. Execution of the proposed trial project in Tasmania would provide an opportunity to explore this particular issue in detail as well as examine how FFR could be operationalised (dispatched) in conjunction with traditional frequency control services.

b) TasNetworks is supportive of the concept of introducing an FFR service definition given the relatively obvious benefit/need for such services going forward. The Irish model[11] is considered a 'good place to start' as it is a sensible approach that dovetails well into the existing FCAS framework. TasNetworks suggests that trying to sub-divide FFR into multiple components is an unnecessary complication and it would be better to create a single pool of 'comparable' capabilities rather than separate pools of 'equivalents'. Once practical experience is gained with FFR services, alternative arrangements can then be considered.

c) In relation to Figure 6.3 in the *Issues Paper*, the basic concept as presented is a reasonable starting point however it is important that the interrelationship between FFR and the existing fast services is appropriately captured. As shown above in Figure 4, the provision of FFR may reduce the fast FCAS requirements by creating more time for governors to respond before the frequency nadir is reached. The FFR does not need to be sustained for much beyond six seconds to enable slow FCAS service providers to assist in place of the fast services. This is material as the capability of plant to respond to frequency deviations in this time frame is significantly better (as evidenced by available volumes and corresponding prices in the FCAS markets). A potential outcome is that the provision of FFR reduces the need for fast FCAS but slightly increases the need for slow FCAS.

   It is important that the 'full value' of any FFR response be appropriately captured and not diminished by simplistic assumptions based around perfect linear responses starting and finishing at discrete points in time.

Question 17 Technical characteristics of emerging sources of FCAS

As discussed in Question 15, TasNetworks is currently investigating the benefits and application of a new innovative solution that has been developed by Siemens. The SVC Plus FS solution is in effect a STATCOM coupled with energy storage. The device is capable of very fast acting, continuous control of both reactive power (being the traditional domain of STATCOMs) and active power. The energy storage is in the form of super capacitors which are three to five times less expensive than batteries with a seven to ten times smaller footprint (for the same installed MW capacity) which also reduces installation costs.

[11] See section 5.2.2 of the Issues Paper

AEMO have clearly described the 'need for trials' in Section 3.5 of their '*Fast Frequency Response in the NEM'* working paper and have sighted recommendation 2.9 of the Finkel Review Final Report as also supporting a need for proof-of-concept testing. TasNetworks has recommended its proposal to both AEMO and ARENA as a project worthy of immediate consideration.

Question 18 Managing the frequency impacts of non-dispatchable generation

As discussed in Question 10, TasNetworks' current view is that the existing FCAS framework will need to evolve to cater for the impacts of the energy transition that is already underway. The ongoing growth of non-dispatched generation is likely to affect frequency regulation as well as potentially contingency response requirements (given the increased level of uncertainty around the ability of some small scale generation to successfully ride through network faults). TasNetworks would suggest that the physical mechanisms used to deliver frequency regulation needs to be reviewed, as well as the need for at least the inclusion of FFR services into the FCAS framework.

In relation to the trade-off between improved forecasting and reliance on higher levels of regulating FCAS, TasNetworks' view is that 'you would do both' at the outset and then apply the '95% rule', i.e. at some point, the cost and effort to improve the forecasting models to gain a relatively small improvement in performance will outweigh the costs of mitigating the error via dispatching more regulation capability. It is unlikely that doing one *or* the other will provide the optimum solution, but will rather entail a combination of both.

Question 20 Co-optimisation with other markets

The various sub-sections to this question are important. TasNetworks will continue to consider the issues that are involved. At this point in time, we can offer the following.

TasNetworks believes that there is definite scope for inertia and fast FCAS to be co-optimised. To do so, it will be important to understand what technical issues define the need/s for having inertia present and whether the technical characteristics delivered from alternate sources can produce an equivalent outcome. As described above, in the Tasmanian network FFR can alter the ROCOF in the post fault recovery period ($ROCOF_2$) and thereby have a positive impact on reducing overall inertia requirements. FFR cannot replace all inertia because of the reasons outlined above. The provision of FFR also has the impact of reducing fast FCAS requirements.

Using this example, it would seem plausible to consider the costs of the FFR service versus the equivalent costs of the fast FCAS and inertia that could be potentially displaced. If the FFR service is cheaper overall, then there can be a corresponding reduction in payments to the other services.

TasNetworks is mindful that such concepts need rigorous analysis both from a technical and market frameworks perspective. The proposed Siemens project in Tasmania would provide a practical mechanism through which to undertake such a review.

Question 21 Consistency in the provision of system security services

Given the significant differences between large transmission connected generators and distributed energy resources (DER), TasNetworks believes that a 'fit for purpose' approach is required as a first principle, rather than necessarily aiming for absolute consistency. Consistency should be applied at a policy level, but attempting to apply the specific technical requirements of the National Energy

Rules Chapter 5 to DER, even if aggregated to something greater than 30 MW, will most likely not work in practice.

Aggregated DER is going to be, by definition, the combined response of lots of different individual devices, each with its own performance characteristics (albeit having some common components such as multiple inverters of the same type offering similar responses). The response from an aggregated block will always be uncertain and continuously variable as individual units come on and off line as a result of customer network connections dropping out etc. It is not practical to test and commission a block of DER and declare it to have a completely 'known' characteristic across all operating conditions.

This is in direct contrast to large individual *generating units* or *generating systems* connected to the transmission network. While the latter may still be the aggregation of multiple smaller units, such units are for all practical purposes 'identical' in terms of their design and performance characteristics. Furthermore, the availability of real time monitoring via SCADA allows for any differences in the overall *generating system* performance to be compensated if individual units are offline.

Thus DER and traditional generation are distinctly different, so a 'consistent approach' needs to recognise these differences and the regulatory arrangements need to be tailored accordingly.

Question 22 Frameworks for the connection and operation of distributed energy resources

TasNetworks agrees that DER connection frameworks have largely been driven by DNSPs looking to mitigate the impacts on their local distribution networks without (almost exclusively) consideration of system security more generally. A potential exception to this general statement is any consideration of under and over frequency trip settings. As an example, TasNetworks has stipulated the minimum requirements for such settings to achieve consistency with the Tasmanian FOS.

The connections framework has focussed equipment suppliers to provide inverter capabilities that address DNSP issues. However, a downside is that stipulating something like a 0.9 power factor requirement limits the ability for an aggregator to utilise the flexibility of the inverter fleet to provide network support or security services. The 0.9 p.f requirement, as a blanket rule, is a blunt instrument but there are few other options for DNSPs to control voltage at the moment. Remote communications and coordinated control systems could unlock future opportunities, but further work is required with clear linkage to current industry work in adopting the Distribution System Operator concept. Other examples include the balance between fault ride-through and fault clearance/islanding on the distribution network, where safety and system security need to be carefully coordinated.

In terms of other barriers, the following can be considered:

a) The aggregator market is still relatively immature. There may be potential risks in transferring some aspects of system security to new entrants and how this is appropriately managed needs to be considered.

b) The ability of DER to provide frequency control services has not been proven at scale and questions still remain in regards to the ability of inverters to remain connected immediately following significant network disturbances. The potential application of 'probabilistic' system security criteria may need to be established whereby only a portion of the total capability assessed as being available is actually relied upon.

c) There is a definite need for more field trials to determine how to operationalise system security services coming from DER. A lack of practical experience at the current time is a factor in TasNetworks' view. How to structure such trials needs to be considered noting that the existing 1 MW minimum bid for FCAS has limited aggregated storage trials.

d) There is a risk that DER could create local system security requirements which then the DNSP may end up paying the same DER provider to mitigate. There should be a requirement that DER does not create additional system security requirements.

Question 24 Technical challenges

The 'firmness' of aggregated DER response still needs to be proven and confidence in the systems that support it gained. While technically possible, the exact level of response that is readily achievable has not been proven in the field across different network topologies. The firmness of the aggregated response also depends on the physical systems that are involved. Frequency response based on local measurements has less failure points than a scheduled demand response or generation reduction scheme that would involve accessing third party data centres and communicating via home internet connections (for instance).

Consideration also needs to be given to existing network infrastructure limits. Our distribution network has been built and designed around load diversity and an after diversity maximum demand (ADMD) of 4 kW per household. This is ADMD is changing, and in the presence of an automated response from DERs to a common system wide signal, such as frequency or pricing, a coordinated (synchronised) response from a significant number of devices is likely to cause issues in the distribution network. This needs to be considered in light of the increasing average size of inverters that are now being installed. Many customers in Tasmania are installing systems larger than 5 kW, and going forward, 10 kW inverters may well become standard.

In terms of other technical challenges, TasNetworks reiterates the need for adequate fault ride through performance if DER is to be relied upon for the provision of various system services.

Question 25 Commercial challenges

TasNetworks notes that the Issues Paper doesn't consider customers' views and attitudes. The assumption would appear to be that customers will want to participate (to provide services from their DER) because value exists.

The social science research coming from the CONSORT[12] Bruny Island Battery Trial points to residential customers having other drivers and not always being comfortable to sell their power even for a 'good price'. It is not necessarily the case that price signals alone are sufficient to solicit participation and other factors appear to come into play. The 'customer aspect' of commercialisation needs further work as it is clear that overcoming all of the technical and regulatory issues may still not deliver the desired outcomes if there is not a willingness to participate.

[12] CONSORT is an ARENA funded research project in partnership with TasNetworks as a member of CONSORT (CONSumer energy systems providing cost-effective grid suppORT), which also comprises Reposit Power, The Australian National University, The University of Sydney and University of Tasmania.