PacificHydro

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Mr John Pierce
Chairman
Australian Energy Market Commission
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Dear Mr Pierce

ER00059: Pacific Hydro submission to Review of Frequency Control Frameworks

Pacific Hydro thanks the Commission for the opportunity to comment and to provide input to the Review of the Frequency Control Framework.

Founded in Australia in 1992, Pacific Hydro is a global renewable energy owner, operator and developer. It operates a high quality, diversified portfolio with an installed capacity of ~850 MW across Chile, Australia, and Brazil; it is also developing a substantial number of projects totalling over 2 GW of potential capacity worldwide; and has a growing electricity retail business in Australia.

Pacific Hydro has an established record of identification, development, and operation of renewable energy assets, significant in-house expertise, and is a responsible market participant.

Pacific Hydro's first assets were micro-hydro projects on existing dams and waterways, followed by construction of The Ord Hydroelectric Power Station and transmission network in 1995. The company subsequently expanded into overseas markets, and constructed Australia's first commercial wind farm at Codrington, Victoria in 2001. After a steady build of assets (Challicum Hills, Portland, and Clements Gap), a sale process, change of ownership, acquisitions, and construction, the company now operates over 450MW of installed wind and hydro capacity in Australia with a development pipeline of 1200MW.

At this point in time, as Australia looks to increase the volume of renewable energy in its electricity supply, it is worthwhile to revisit the assumptions that underpin the FCAS markets and why in Pacific Hydro's opinion these markets are ill suited for a future in which there is greater diversity in the technology, more distributed energy sources and a diminishing volume of large synchronous units.

Introduction – the importance of frequency control

There are three characteristics of a good bulk electric supply system these are:

- Constant Frequency,
- Constant Voltage and
- Reliability.

Power systems are highly non-linear and consist of the most complex, expensive and critical infrastructure in any developed nation. Primary control of frequency is essential for the reliable and secure and operation of any power system. Primary control is provided by the governors on synchronous units or other primary controls on newer technologies that act to respond directly to the frequency measured on their terminals. Primary control should be correctly designed and unimpeded by other control actions. In the past, each public utility had a dedicated group of specialist control engineers who worked with the technicians at power stations to test and set the controls to ensure that they were working, stable and co-ordinated with all other controls within the system. The accurate and secure dispatch of the energy market depends on retaining tight control of frequency, the control of active power and frequency are one in the same, the market cannot consider active power control in isolation from frequency control as the two are dependent on each other.

Without constant frequency, a network suffers a number of second order effects which make control of the network difficult. Two examples of these second order effects are:

1. The mathematics that is used to simulate and assess the network performance for contingencies assumes the frequency to be at 50 Hz. The dynamic models that are used to simulate the machines assume a constant flux in the electromagnetic field of the unit; the impedances, the rotor speed and electrical angle are important values that are initialised based on frequency. In order for simulations of the power system to produce a reasonable estimate of how the power system will respond in specific circumstances. Failure to maintain a steady constant frequency affects the ability to reasonably simulate the response of the power system and assess its stability for any given contingency.

2. Changes in frequency cause changes in the impedance of the inductive and capacitive elements in a network. Variations in impedance have an impact on voltage. Accordingly, maintaining constant frequency contributes to voltage stability and the efficiency of operating the network.

There is a tendency to over simplify the role of frequency as being just “generation equals supply”. This simplification fails to appreciate that there are further, more complex reasons for controlling large synchronous machines to synchronous speed.

Deterioration of frequency control in the NEM

The current deterioration in frequency control is directly due to the de-tuning or widening of primary controls on the synchronous units, coupled with unit controllers that drive units to obey dispatch targets or AGC targets over riding primary control responses. This deterioration would be present regardless of whether there were renewable energy technologies on the grid or not. It is worth noting that asynchronous or inverter controlled generation is not dependent on frequency and does not oscillate against frequency; it simply keeps producing relatively stable power which in many ways has a damping effect on the power system. Further comment will be made on what renewable energy can do to contribute to frequency control late in this paper.

The management of large ac power systems starts with the control of each synchronous unit. In order to control large synchronous machines it is essential that the primary controls are effective, stable and adequately damped. The response, rise time and settling time of both the automatic voltage regulator (AVR) and the governor are critical to the management of the unit’s terminal voltage and power balance. The synchronous units must also be controlled in a stable manner with other units within the power station and neighbouring units within a region. In a similar manner all units within a region must be controlled and stable against all units in a neighbouring region.

Prior to the NEM, the generating units had mandatory governor control, each state operated its own area of control, held its own reserve and the interconnectors were controlled by means of tie line bias. This is a proven power system control practise to regional management as each region that is weakly interconnected is responsible for managing the risk of being separated, and therefore must strictly control frequency. The adopted control practises through the FCAS markets only worked when sufficient governor controls remained in accordance with the original settings (i.e.: primary response supported the normal operating band). Mandatory governor response ensures that all units are contributing to maintaining the frequency and will respond to help stabilise an event.

The economic decision to increase trade between regions to the technical limit of the interconnectors meant removing the local area control and tie line bias – this was possible only because all units had tight frequency control. When the larger proportion of generators implemented controls in accordance with the FCAS design the deterioration in frequency became obvious. The introduction of the FCAS markets did not fully contemplate the removal of primary control from the normal operating band as a widespread practise.

This change to frequency control has been enabled through the existing FCAS framework which describes and expects primary control action to commence at the boundary of the normal operating frequency band. The Automatic Generation Control (AGC) that sends the regulation raise and lower signals for the FCAS regulation services is a controller that is intended to correct for small deviations in frequency and time error correction. When the frequency deviates from 50 Hz to 49.85 Hz (i.e., at the boundary of the normal operating frequency band), it must be understood that the energy mismatch is in the order of 800 MW and this cannot be considered a small deviation. So it is questionable as to why there is an expectation that the AGC alone can recover the frequency.

Inertial response

Much has been said about the importance of the inertial response of synchronous units setting the rate of change of frequency during contingency events, however, it must be understood that the inertial response is inherent and active all the time. Whenever the energy demand on the terminals of a synchronous unit changes this is taken directly out of the rotating electromagnetic field of the machine. Any change in electrical power demand on the terminals of a machine translates to an energy mismatch between mechanical power input and electrical power output which directly affects the rotational speed of the shaft.

Elgerd[i] describes what happens when there is a small change in load drawn from the generator connected to a load:

> "The speed changer position will not be changed. … Since there is no change in the turbine power, upon the onset of the load increase the generator finds itself momentarily in a power-deficiency situation, delivering more than it receives. It can do this only by "borrowing" energy from somewhere, and the lending source is the stored kinetic energy of the rotating masses. Since we thus start to consume this energy at the rate ∆PD MW, the speed will drop."

Elgerd goes on to describe the control action of the governor:

> "As time passes and the speed decreases, the speed control mechanism (the governor) goes into effect. Since more power being is thus being generated, less energy will need to be "borrowed" from the kinetic storage, and the speed will drop at a decreasing rate. Eventually, we will level off at a new static steady state equilibrium characterised by lower speed and a new generation that has increased with the exact amount to offset the original load increase."

This example explains that governor control arrests the deceleration and acts to match the power but cannot in isolation return the speed to 50 Hz. If the governor fails to increase the energy input to the machine the deceleration will continue until the “borrowed” energy is supplied from somewhere.

The importance of energy balance

There are three components that make up any step change demand increase:

1. “Borrowed” kinetic energy from the rotating system machines (synchronous)
2. Increased generation (provided by primary control)
3. “Released” customer load (load relief)

In control theory, the governors and the AGC control mechanisms are co-ordinated and all machines within a region act in unison. The area control through the AGC performs this role in the minutes following an event.

As described in the introduction above, the difference between the unit control expected in engineering studies and the unit control in the market is as follows:

In engineering studies with the governor active, the controls will act to increase the energy input to the match the borrowed kinetic energy that is taken as electrical power drawn on the terminals, that is the controls act to increase the mechanical power to equal the kinetic energy drawn from the machine when a step change occurs. This contributes to stabilising the system and brings the unit to a new equilibrium steady state.

In the market, the unit controls act to drive the machine to its dispatch target only, the borrowed kinetic energy taken from the machine due to a step change on the unit’s terminals is “taken back” and the controller drives the unit back to its dispatch target, leaving a larger deficit on the power system in the period straight after the event. This does not contribute to stabilising the system and leaves a deficit on the system results in a larger sustained frequency deviation than what would have occurred if the unit had acted to match the energy drawn on its terminals.

The remainder of this document will address the questions posed by the Commission in the issues paper.

Yours sincerely

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Pacific Hydro

Questions and Pacific Hydro answers

1. **Scope. Are there any other issues relating to frequency control that should be included within the scope of this review?**

The scope should consider whether the control philosophy adopted by the FCAS market is suitable to the operation of a long, weakly interconnected ac power system. It should review whether a market that aims to "minimise" services and costs delivers the reliability and security requirements necessary to have the energy dispatch conform to the security constraints. The scope should consider that this is no longer a market problem or policy problem, but it is a deep seated control engineering issue for the operation of the power system. The scope should seek to obtain expert power system control advice to assess what is suitable for the efficient and stable management of the power system.

The scope should recognise that the FCAS market framework has enabled and promoted the deterioration of the frequency control without understanding the complex engineering reasons for the previous control philosophy. To this extent the scope should recognise that the existing framework is unfit for the operation of a large weakly interconnected power system, whether it had new technologies connected to it or not.

There are drivers for change, but many of the new technologies are not dependent on frequency in the same manner as the synchronous fleet is. The deteriorating frequency control is detrimental to the synchronous units and is placing them at risk of damage. The control of all generators on the power system is a matter of understanding that changing active power in accordance with a dispatch signal in isolation can and does affect frequency.

The scope should consider that there must be a hierarchy of control on the power system which is necessary for safe, efficient and secure operation, and that the market rules, its governance and structure must not undermine or conflict with that control hierarchy.

2. **Drivers of degradation of frequency performance in the NEM.**

   a. **Do stakeholders agree with the drivers of the observed long term degradation of frequency performance as identified by DIgSILENT?**

   Yes, and these changes must be understood in light of the delayed response to contingencies as well. Wide deadbands on governors mean that the small amount of contingency response that is enabled is likely to be too little too late when large abnormal events occur.

   b. **Are there any other drivers of frequency degradation in the NEM that are not mentioned here?**

   Dispatch can and does send units in a manner that is contradictory to frequency recovery. AGC can and does do the same.

   There is a comment that primary control is almost immediate, but this has to be understood in light of the technology and energy available to the unit. The governor on a steam turbine must sense the decline in rotational speed of the shaft, the actuators have to then open the valves to increase the flow of steam to the turbine and the turbine has to be accelerated against a deceleration force to increase the rotation of the shaft and equalise the input energy to the output energy. On a hydro there are water column time constants to consider, typically hydro generators do not have deadbands. These must all be considered as it still takes time to increase power input to a unit, if there is less inertia in a system, it is important that these actions commence earlier.

3. **Materiality of frequency impacts from non-dispatchable capacity.**

a. **What are the likely impacts on frequency of increasing proportions of non-dispatchable capacity, and reducing proportions of scheduled generation?**

The evidence shows that the asynchronous and inverter connected generation has little or no impact, does not contribute to the oscillatory behaviour, and tends to have a dampening effect. As these sources of power generation increase, the control between the synchronous fleet will need to be co-ordinated to ensure that they operate together in a stable and efficient manner. The “non-dispatchable” generation such as rooftop solar will reduce load and the system will become lighter, which will require “retuning” of all control responses.

On a point of clarification, all large generation can be dispatched – it is a matter of forecasting and controls.

b. **Are there any significant impacts on frequency that may occur from changes in output from individual large scale semi-scheduled generation (large solar and wind farms)?**

The largest impact on frequency from large scale generation would be for it to trip off, this is the same effect as the loss of a large synchronous unit. The variations in power output that occur within a 5 minute period are much smaller and are manageable. To better manage the impact on frequency, large scale plant should implement a form of connection point frequency droop control, but this should only be done when all generating units implement appropriate control, otherwise any plant providing this will be over worked.

In the discussion on the drivers for change on page 48 of the Issues paper, the following statement is made:

“The South Australian wind study report, prepared by AEMO, considered the impacts of the variability of utility scale wind generation in South Australia. The report analysed the changes in total output of wind generation in South Australia over five minute periods from 2010-11 to 2014-15. It also considered the variations in total demand and residual demand (demand less wind generation) over five minute periods.”

The AEMO report into South Australia wind covers the period 2010-11 to 2014-15 in which the AWEFS system was proven to be in error. From mid-2012 through to 2016 the AWEFS system was declared to have a scheduling error[ii]. This particularly affected the 5 minute and 10 period of the wind forecasting. Relying on this analysis as a reason to say that there is a “dispatchability problem” is flawed. Furthermore, when AEMO is questioned regarding the “variability” figures and asked whether they have taken frequency into account in the raw figures, the answer is negative, which means that the variability is overstated as there will be times when the variability will be positive to frequency and other times when it is not.

Examination of the four second data for all the generation on the eastern seaboard reveals that there is little variation in the collective action of the renewable energy generators. The problem of variability is more a forecasting issue than an immediate frequency control issue.

c. **Does the analysis for wind generation above hold true for large scale solar PV? Does large scale solar PV output change more rapidly than wind output? Are changes in solar output more difficult to forecast?**

Large scale PV can be controlled using a form of droop control and forecasting. It will need to "soften" its rates of change, but all control should be done with frequency control as the primary control function. External market driven signals must be secondary to this action. The consideration of daily movement must be understood as a forecast issue and a matter for predicting how much "reserve" is required in the hours ahead. This is a forecasting and "spinning reserve" problem, which can be minimised if the reduction or increase of PV is done with known accuracy and in consideration of frequency control.

4. **Drivers of change. Are there other drivers of change affecting frequency control that are not set out in this section? If so, how material are they?**

The loss of control hierarchy in the power system is a driver of change. The market signals were always intended to be external to the control of the power system. Fifteen years of FCAS market has made the FCAS enablement and AGC signalling the major controlling action on the large units as generators seek to comply with their dispatch targets in a linear fashion. The market was never intended to supplant system controls, however, this is now evident. The loss of good power system control practise is a driving factor along with generators complying with the letter of the rules without consideration or understanding of the impact on the power system.

5. **Assessment principles.**

a. **Do stakeholders agree with the Commission's proposed assessment principles?**

The principles are reasonable, however, further consideration should be given to elevating the role of power system control philosophy and its role in the delivery of "security". A market cannot and will not deliver the engineering controls necessary to correct this problem in isolation. Technology neutrality is in principle good to retain, while considering that all technologies have their own technical characteristics that must work within the limits of their control boundaries.

b. **Are there any other relevant principles that should be included in the assessment framework?**

Consider that efficient frequency control is provided when all units act to support the power system. To this extent it is most efficient when every unit does a bit to help. This may mean that the "market philosophy" of minimising cost (and therefore service) is contradictory to the efficient needs of a stable power system.

6. **Assessment approach. Are there any comments, or suggestions, on the Commission's proposed assessment approach?**

The principles should consider broadening the assessment to looking at performance criteria from all units and find a way to value the control actions that are necessary to manage the power system. Assessment must take into account good electricity industry practise, that is, what controls do other power systems use and what is and is not working. This is requires sound engineering judgement and advise. The market approach must conform to good electricity industry practise, it is not in the long term interests of the consumers to wear out the existing fleet of generating units due to poor control practise.

7. **Are stakeholders aware of any other costs or impacts linked to the degradation of frequency control performance in the NEM?**

   The cost is starting to show up in unit failures. For example recent boiler tube leaks are a direct outcome from varying the pressure controls on thermal units, varying flux from the loss of constant control will be causing heating effects on the windings of units. Varying the frequency from 49.85 Hz to 50.15 Hz causes a 0.06% change in impedances within the power system and will affect voltage control.

8. **Are there any other risks that stakeholders are aware of with respect to degradation of frequency control as represented by the flattened frequency distribution within the normal operating frequency band shown in Figure 5.1?**

   The data shows that the large synchronous units are hunting against each other, which is a consequence of the lack of primary control. This risks damage to machines through unnecessary cycling, as a lack of damped primary control action leaves the system at risk of oscillatory behaviour. The loss of appropriate speed control means a loss of damping torque on units.

   The control action for a large contingency starts too late and in some cases is too little too late due to the governor action commencing at the boundary. The energy deficit between 50 Hz to 49.85 Hz would be in the order of about a 800 MW mismatch, the contingency services are only about half of this and start after the deficit has been established. In lighter systems, as inertia reduces, the changes happen faster and the controls on the synchronous units must start earlier not later in order for the units to remain in synchronism.

9. **Are stakeholders aware of any other international experience in relation to primary frequency control that is relevant for this review of frequency control frameworks in the NEM?**

   ERCOT have tightened their governor deadbands, this is because they recognised that they had less inertia in their system. The newer wind farms and solar farms can provide an appropriate contribution through droop control but this should only be done when the frequency is tightened up.

10. **Mandatory primary frequency control.**

    a. **What are the advantages and disadvantages of mandating primary control for all generators in order to improve frequency control during normal power system operation?**

       The advantage is that everyone contributes to supporting the control on the power system and the controls are located all over the system. The primary control action across all units then aids in the response to large contingencies and helps each unit re-establish its new energy equilibrium. Furthermore there is risk of human error trying to predict or manage the unexpected contingency outcomes when abnormal system conditions occur. There is little or no disadvantage having all units contribute primary control in the normal operating band, there is a control engineering issue to ensure that all control systems remain stable and responsive. There is a significant advantage having all units behave in accordance with their capability as described in the dynamic models, this enables more accurate and reasonable system modelling and simulation. It provides confidence to the system operator and enables efficient and secure operation of the power system.

b. **What factors should be considered in the specification of a mandatory primary frequency control response?**

The specification must consider the range of responses possible from all technologies. Within the synchronous fleet there are differences (for example, hydros traditionally do not have a deadband and must manage the time constants associated with the water column, whereas thermal units usually have a small deadband).

The specification should be engineered to include a maximum deadband and an appropriate range for frequency droop control.

c. **Are there any regional issues that should be considered in assessing whether primary frequency response should be a mandatory obligation for registered generators in the NEM?**

Yes, primary control must be available and active in all regions in order for the system stability guidelines to be met.

d. **Should an obligation for generators to be responsive to changes in system frequency outside a pre-defined dead band include a required availability reserve, such as 3 per cent of a generators registered capacity, as is the case in Argentina?**

The reserve capability and response within a region is critical to ensuring that a region can survive abnormal separation events or other large contingencies. A reserve mechanism will need to be developed but it must be such that it does not provide incentive for units to remove capability from the power system.

Currently, units offer energy into the energy market and they frequently withhold their additional capacity in high priced bands. When the primary control is active this capability will act to respond to contingencies. Perhaps consideration should be given to dispatch periods in which contingencies happen and an appropriate control premium added to the energy price to deal with the fact that all frequency controlling generators will act to control the system. The premium could be designed as a percentage associated with the actual volume of energy delivered to the system in accordance with the control performance of the individual units. In this manner those who do the heavy lifting get paid more in that period and the recovery period, and those who do less receive less. If a unit acts in a contradictory manner there could be a percentage subtraction. Provision could be made for further reserve capacity under periods of forecast shortfall

11. What are the advantages and disadvantages of procuring primary control through bilateral contracting as a means to improve frequency control during normal power system operation?

Contracting is again looking for a minimal amount of service and it does not resolve the requirement that the governor control action is essential for reliable operation of the power system. It may be that contracting provides the additional reserve for the periods in which there is a reserve deficit forecast, this may provide a path to solving the forward reserve issue, but this should not be confused with primary control.

12. Market based options for primary frequency control.

a. **What are the advantages and disadvantages associated with the two options presented for earlier provision of primary frequency control:**

(i) Using the existing contingency FCAS for provision of primary frequency control and narrow the normal operating frequency band to trigger a primary frequency response closer to 50 Hz.

(ii) The establishment of a new primary regulating service to provide primary frequency control within the normal operating frequency band, separate from contingency FCAS.

Pacific Hydro sees no advantages in market based options for primary control as ‘competitive” provision of service is about trying to minimise the service. This is not suited to frequency control as primary control must be enabled and active on all units to protect and operate them in a stable manner.

Market mechanisms aim for competitive minimisation of service. The control of the eastern seaboard requires firm tight control from all areas of the grid. There is no guarantee that a market under interconnected normal operating conditions will source frequency control services in all areas in the amount necessary to ensure that an event will be correctly managed. Furthermore, enabling and disabling the primary control in the manner that the current market does is altering the frequency response of the power system in a manner that is not examined in the system studies that design the transfer limits. Setting a regional requirement is unlikely be cost effective due to the market power of some generating companies. The underlying controls need to be active to stop the synchronous units hunting against each other. Redesigning the market boundaries would help but not resolve the manner in which the frequency response is changing in accordance with dispatch. This threatens system security in a profound manner.

The proposed changes to the NOFB discussed in Figure 5.2 remain inappropriate as the regulation band is still too wide for the AGC to control the eastern seaboard appropriately. It would be better to add a “regulation band” within the NOFB and ensure that the primary control commences within that band. Understanding that hydro units typically have no deadband, and that thermal units in the past would have had a deadband of 10 to 20 mHz (that is +/- 5mHz to +/- 10 mHz). Gas units require tight frequency control in order to be able to respond to frequency deviations, if their response starts too late the compressors that maintain gas pressure to the units is affected.

AEMO’s fast frequency response paper is referred to on page 76 and the quote states:

> *“In the past primary frequency control was provided by the governors that controlled the output of synchronous generators. However, as the generation technology in the NEM changes due to the increase in renewable and inverter-connected generation, it is more appropriate for generators or load to provide "active power control" when required, rather than governor response.”*

The concern with this statement is that the authors think that “governor response” is somehow separate from active power response and that the market would know (through dispatch) when “active power” is required. This is flawed thinking as the governors on synchronous machines act to correct the rotational shaft speed of the synchronous units to eliminate the energy deficit or excess that occurs on the terminals. Inverter controlled devices and asynchronous units can have controls that mimic the actions of governors and all active power control should be done with consideration to frequency control and not in ignorance of it as is the case now with the energy dispatch.

13. **Are there any aspects of the existing Causer pays procedure that stakeholders believe are acting to discourage the voluntary provision of primary frequency response?**

Yes: the existing causer pays procedure measures generating units in an inappropriate manner with a poor sample rate and against a number that cannot be used in a control system. The FI number from the AGC system is a measure of the aggregate area control error, this is a time delayed calculation of volume of power required to recover the system frequency to 50 Hz. Units cannot control to this number – they should be controlled to frequency, that is, if a synchronous unit acts to control the rotational speed of its shaft by increasing energy to act against a falling frequency it is doing the right thing and should not be penalised. Likewise, if a wind farm curtails and holds or decreases its power rather than increasing active power when frequency is high, it is doing the right thing and should not be penalised.

Causer pays procedure and methodology has fundamentally contributed to units actively removing primary control from the power system.

Units in the past that acted to dampen the system mode have been penalised through the CPF calculation due to the sample rate of the 4 second data. Keep in mind that the ACE in the AGC does not assess the system mode.

14. **Frequency monitoring and reporting.**

a. **What are the potential benefits or costs associated with a requirement for AEMO to produce regular frequency monitoring reports?**

AEMO must produce frequency monitoring reports in order to obtain the oversight of whether the power is being well managed. The failure to produce reports across a three year period occurred at the very time the frequency deteriorated in an unprecedented manner. The costs of such reports is minor as the data is captured in the SCADA systems, the benefits of assessing the performance is almost infinite, failure to correct the loss of frequency control could be significant to the Australian economy.

b. **What metrics should such frequency monitoring reports include?**

This will depend what future obligations are placed on generating units. The NEM used to be quite transparent and NEMMCO used to declare which units had responded and which had not to various events. This type of information no longer appears in the incident reports. Consideration should be given to open and transparent control performance as the power system only works efficiently when all units work collectively together to support the power system.

Generally monitoring should be aimed at identifying the broader changes that occur slowly over a long time, like a slow leak in a tyre sometime it is hard for the operator to see these issues. Monitoring should be done to try to pick up on the changes that operationally are hard to see.

15. **Defining FFR. What are your views on AEMO's advice on how and when FFR might emerge in the NEM?**

The Commission's work in the Future Power System Security Program has identified a number of issues which were raised by NEMMCO in 2006, when the inertial problem was first discussed in the WETAG. The program is relevant but it must be taken in context. The FPSS program of work failed to identify the underlying loss of primary control on the large synchronous fleet. It is critical to understand that much of the propositions in the FPSS program cannot in isolation correct the problems caused by the majority of the generation fleet being poorly controlled in accordance with a flawed framework. Furthermore, any inertial contribution from synchronous units or other devices is only as good as the primary control that follows the inertial contribution as discussed in other parts of this submission.

Fast frequency response is simply asking for good primary control action from new technologies, which can be faster than large thermal or hydro units. However, the response from the new technologies will be quickly swamped if the large unit responses are inappropriate or contrary to good control. It is evident that both dispatch and AGC can and often is, contradictory to good control. Hence, correcting the large synchronous units' responses is critical. Following that, the new technologies can be correctly integrated to provide fast response in a manner that is co-ordinated, studied and integrated to the overall power system control philosophy. Currently, the call for fast frequency response has failed to understand the loss of primary control on the large units. The inertial contribution of the large units must be followed by those units increasing their input energy to arrest the deceleration that is present on each of those machines.

Pacific Hydro is not opposed to requiring frequency control capability from new technologies. Pacific Hydro is opposed to the proposition that the new technologies can provide all the response required to manage the system which is what will happen if the large synchronous units are not correctly retuned. Anyone providing fast response will be over-worked if the current failure in frequency control remains in place. This will reduce the life of new equipment through excessive cycling.

16. **Potential options for making changes to FCAS frameworks. What are your views on the above indicative approaches to varying the design of FCAS services, and on other potential changes?**

As discussed previously in this paper, "dispatch" of primary control is ill suited to managing a power system and causes the frequency response to move around and may or may not be sufficient to provide the response necessary to secure the system. A market mechanism that aims to minimise the service and the cost undermines the very control of the power system and therefore its reliability.

17. **Technical characteristics of emerging sources of FCAS. What other emerging sources of FCAS should the Commission be aware of?**

Modern controls are remarkable, and most energy sources can be controlled to deliver energy fast or slow, in proportion to frequency deviation or not at all. Frequency control is simply making the active power response of an energy source responsive to the frequency of the system. Current market dispatch and regulation services are often contradictory to good frequency control. Fixing the existing frequency control should be the top priority, new technology can then integrate with appropriate governor like control mimics.

18. Managing the frequency impacts of non-dispatchable capacity.

a. **Is the existing FCAS framework sufficient to maintain frequency as greater proportions of non-dispatchable capacity enter the power system?**

No – the existing framework would have created this poor frequency control with or without the “non-dispatchable” capacity. Note, Pacific Hydro takes “non-dispatchable” to be residential PV, all large sources are dispatchable to extent of their forecast availability. Pacific Hydro notes that much of the variability studies performed by AEMO have not taken into account that variation in power output can be positive to frequency. The figures were produced without considering this fact, hence the variability figures are over stated.

b. **Would it be more efficient to improve the forecasting of non-dispatchable capacity to reduce imbalances in supply and demand, or to rely on higher levels of regulating FCAS to manage those imbalances?**

Large semi-scheduled generators have been calling to take control of their forecasts for nearly two years now. The forward availability of renewable plant for the dispatch and near term forecasting should be performed by the participant as they are best placed to provide with accuracy what their plant availability is. AWEFS has been in error for over four years and much of the variability figures used in the FPSS reports failed to acknowledge the scheduling error. To this extent, there has been an over stated problem in the declared variability of wind farms. ASEFS suffers similar problems as it has the same architecture. An accurate forecast for the dispatch period is essential as it is affecting the dispatch of the power system.

c. **What other efficient options are there to manage imbalances in supply and demand resulting from the variability of non-dispatchable capacity within the five minute dispatch interval?**

The four second data does not support the theory that there is large variation in renewable energy. Within 5 minutes, on average, the renewable energy is more stable than the synchronous fleet. Variability of all renewable units dampens between clusters of units or between wind farms, but it is still possible to ensure that power output to the grid is managed in a manner that supports frequency. There are technologies that can be implemented to control the power input to the system to avoid having a detrimental impact on frequency control. Isolated grids such as King Island have solved this problem. Batteries, dynamic load banks, flywheels on alternators are all examples of possible control technologies.

19. Cost recovery arrangements.

a. **Do you consider existing cost recovery arrangements for contingency FCAS to be appropriate?**

No – currently it would appear that generators are paid for services that fail to adequately control frequency, even though it is within the FOS. The reliability of the power system is undermined by the current framework. The costs are increasing while the frequency control is deteriorating. The example of Kogan Creek raises the “run way” debate again which the NEM explored in great depth around 2003 – 5.

b. **If not, how should cost recovery arrangements be changed?**

Consider a performance based payment as described earlier in this paper.

20. **Co-optimisation with other markets.**

   a. **Are there other system services, such as inertia, system strength or system stability, that should be co-optimised with FCAS markets?**

   The first and most important step is to return to good engineering control practices. Tightening the system frequency control will strengthen the response of the units and solve many issues that appear on the system. The inertial response or kinetic energy provided by synchronous units is only good if appropriate control action follows this requires the additional mechanical energy into the machine. Currently machines are generally being driven to their dispatch target leaving a larger energy deficit on the power system resulting in a failure to recover frequency. The "system strength" issue is a matter of ensuring suitable control settings and capability, ultimately there are technological solutions to provide additional fault current if required.

   The market has been removing capability from the power system making it less resilient and undermining the controls that have traditionally provided the responses necessary to manage large contingency events. Market dispatch conformance limits unit response and contribution, the market needs to find a way to allow full unit performance and capability to be released to the power system.

   b. **If so, can one service (such as inertia) be optimised first and, if so, why?**

   The inertial contribution of a synchronous machine is a constant; it is taken into account in the transfer limit equations. If units are not available (OOS) then the forward planning for the next day should flag the loss of the inertia through the day-ahead studies that are performed in the control room support planning function. AEMO has the powers to act if the studies reveal a problem. It is assumed that day and week ahead studies are still undertaken.

   c. **Would co-optimisation impact on cost recovery and, if so, how?**

21. **Consistency in the provision of system security services. To what extent is it important that the NER arrangements for the provision of system security services are consistent between providers of such services, e.g. large, transmission-connected generators and distributed energy resources?**

Distributed energy resources need to have well defined system integration standards to ensure that they act to support the power system in the local area. To this extent the distribution codes, frequency control to the connection point and protection needs co-ordination and good engineering practises. Price arbitrage should be limited when system events occur as this could have a detrimental impact on the recovery of the system.

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[i] P328 Elgerd: Electric System Theory: An Introduction chapter 9

[ii] AWEFS UIGF Scheduling error_2012 to 2016_FINAL