Hydro Tasmania

7 December 2017

John Pierce
Chairman
Australian Energy Market Commission (AEMC)
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr Pierce

Frequency Control Frameworks Review (EPR0059)

Hydro Tasmania appreciates the opportunity to provide comment on the AEMC's Frequency Control Frameworks Review Issues Paper.

The energy market is undergoing a significant period of transformation which is bringing a number of challenges for the National Electricity Market (NEM). Key among these challenges is the need to successfully integrate variable renewable energy resources into the market. Building upon the work of the AEMC's System Security Market Frameworks Review, the Frequency Control Framework Review provides a timely opportunity to address the challenges associated with frequency control. Hydro Tasmania believes that the scope of the Issues Paper broadly covers the key issues that require consideration. Hydro Tasmania encourages the AEMC to take the time to fully explore these issues, and in coordination with AEMO and the industry, reach a long lasting and efficient framework for frequency control in the NEM. In summary, Hydro Tasmania's positions on the issues outlined by the AEMC are:

- Hydro Tasmania believes that the AEMC should focus on the procurement of Primary Frequency Control (PFC) as part of this review. Hydro Tasmania believes that the AEMC should recognise the role of PFC within the Normal Operating Frequency Band (NOFB) and a market framework for procurement of PFC should be assessed.
- To this extent, Hydro Tasmania supports the following frequency bands for a new primary regulation market service[1].

[1] http://www.aemc.gov.au/getattachment/0fd91c30-bc61-4d53-8ee3-249eac0123b5/Issues-paper.aspx

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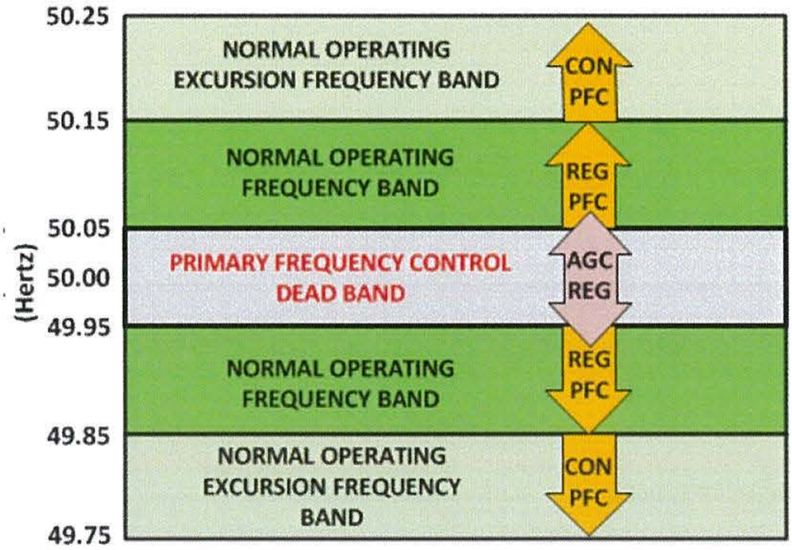
Inclusion of dead band for the triggering of a new regulating primary frequency control service



KEY:
AGC REG – Regulation FCAS coordinated through the AGC system
REG PFC – potential new regulating primary frequency control service
CON PFC – Contingency FCAS (primary frequency control)

- The Issues Paper outlines the actions that some participants have taken to limit the response of their generators to frequency disturbances. There is a definite power system requirement to ensure participants respond more appropriately to frequency disturbances and set the required specification for governor dead bands and droop settings. Hydro Tasmania's preference is that this is achieved using a market procurement of PFC.
- Hydro Tasmania believes that further modelling is required to establish the trade-offs between PFC and regulation FCAS. Conceptually, Hydro Tasmania believes that procurement of PFC will reduce the amount of regulation FCAS being procured. On balance, this arrangement will likely see customers being no worse off financially.
- There are circumstances where signals provided by PFC and Secondary Frequency Control (SFC) settings can send mixed (and sometimes opposing) signals to generators; the result of which can lead to larger oscillations of frequency. This review needs to establish a clearer framework to enable better coordination between PFC and SFC. A more coordinated response will send the right signals to avoid unintended generator responses which exacerbate the problem.
- As the NEM continues to transform, the operation of the market and provision of services is likely to be different in the future. Hydro Tasmania suggests that the AEMC should develop a clear understanding of the technologies and services (such as fast frequency response and inertia markets) that might be needed in the future. This understanding would include how the services will be defined, measured and verified.
- Hydro Tasmania also suggests that the AEMC should consider adjusting the framework for the provision of FCAS Raise contingency services. We believe that FCAS contingency service machines should not have to pay when they are enabled to provide Raise contingency services. Adjusting the framework may provide the incentive for greater provision of FCAS contingency services in the market.

Please see Appendix A for Hydro Tasmania's response to the relevant questions outlined in the Issues Paper. Please feel free to contact Prajit Parameswar (Prajit.parameswar@hydro.com.au or 03 6230 5612) for further information.

Yours sincerely

Allan Jones
Manager Spot Market and Operations

Appendix A

Responses to relevant questions raised in the Frequency Control Frameworks Review issues paper

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

Hydro Tasmania believes the following items should also be considered in the scope of the review:

a. *The addition of a Primary Frequency Response (PFR) category to supplement Primary Frequency Control (PFC) and Regulation services.*
This would recognise the response of uncontrolled resources such as inertia and load response. This is important, as within the first 200ms of a frequency disturbance, these are the only sources opposing the frequency changes which ultimately affect the magnitude of the Rate of Change of Frequency (RoCoF). It is noted that the availability of both these sources are declining due to the increasing penetration of non-synchronous sources.

b. *Trade-offs between different FCAS categories.*
At present, this is considered in terms of fast, slow, delayed and regulation FCAS. We believe it is important to consider how the provision of additional faster responding FCAS could reduce the requirement for delayed FCAS and vice versa potentially leading to lower cost to consumers.

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

a. <u>Do stakeholders agree with the drivers of the observed long-term degradation of frequency performance as identified by DIgSILENT?</u>
Hydro Tasmania believes that the Tasmanian frequency is negatively impacted by the deterioration of frequency performance inside the NOFB, as reported by AEMO since 2014. The main drivers for such behaviour are the withdrawal of PFC provision (increased dead bands) inside the NOFB and the use of secondary frequency controllers enforcing energy targets while disregarding the system frequency. The increase in the variable renewable energy generation may also play a role but it appears to be less significant at this stage than the other factors.

b. <u>Are there any other drivers of frequency degradation in the NEM that are not mentioned here?</u>
Hydro Tasmania believes that the following are drivers of frequency degradation in the NEM:

Interaction between PFC and SFC (via AGC) contribute to amplifying low frequency oscillations in Tasmania. The generator's governor is the ultimate executor of frequency control. Summing together the droop signal and AGC signals (ramp plus regulation) in the governor summing junction creates conditions where these signals have opposite polarity which can either have the unintended effect of cancelling each other out or the same polarity, aggressively amplifying the response.

Hydro Tasmania supports separation of AGC and PFC bandwidths which is equivalent to making AGC the only controller within very narrow frequency band, say ±0.05 Hz and outside this band suspend AGC and activate all PFC (outside generator dead bands).

More active use of AGC suspension could also eliminate observed frequency oscillations. Alternatively, if there is an overlap within operating range of AGC and PFC than a concept of 'intelligent governor summing junction' could be used to reject AGC signals that are in phase with the frequency.

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?

Impact on regulation FCAS: With lower number of synchronous generators, the overall inertial, droop and PFC responses are lower and consequently frequency deviations are larger (with a smaller number of generators left to respond). Consequently, frequency variations in NOFB are bigger and AGC needs to do more work.

Impact on contingency FCAS: Non-synchronous machines protect themselves through a Low Voltage Fault-Ride-Through (LVFRT) sequence that is temporarily withdrawing some energy output during the disturbance. The recovery of the output can take up to a couple of seconds depending on the system strength. These impacts may result in increased contingency FCAS requirements.

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)?

Significant impacts are associated with a sudden change in wind conditions (wind gusts or excessive wind), operation at low wind conditions when the changes in wind turbine output can be pronounced), cloud coverage (in case of solar) and generation forecast errors. At present, there are issues with managing these events.

Hydro Tasmania has observed that in the case of large forecast errors, AGC regulating machines may be prone to providing an unintended destabilising response (in phase with frequency changes). This is often due to high AGC gain and time delays in the processing of AGC signals.

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?

Hydro Tasmania does not have direct experience with large scale solar generation. However, wind generation is considerably smoother through the wind sites diversity and terrain impacts. So even within one wind farm, individual wind turbine responses are not closely correlated. In the case of solar, responses are closely correlated within a small area resulting in an expectation of much higher changes in supply.

Another aspect to consider is the quality of inverters. Wind turbines/ HVDC interconnectors can tolerate much larger changes in frequency and RoCoF than small distributed inverters. There is a danger that some of these inverters will trip on either RoCoF which is set on anti-islanding protection or from a high frequency deviation.

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?

Improvement in power system electronics may provide an opportunity to increase the availability of primary frequency control, provided that the inverters are specified to allow for this. There is a large potential for use of frequency controllers on inverters controlling energy storage devices. However there will be legacy issues created by equipment already in place.

Some inverters will be in the distribution network, with their response offered as aggregated FCAS to the system. This approach needs to be tested for visibility, predictability of response, impact of Fault-Ride-Through (FRT), controllability and reliability of delivery before it can provide predictable response.

The potential of providing FCAS by wind turbines is also encouraging technically, but is typically commercially unattractive.

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

   Hydro Tasmania agrees broadly with the proposed assessment principles.

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

The inclusion of a principle of 'Alignment between technical and regulatory requirements' would be welcomed. The current increase in regulatory focus on Frequency control arrangements provides an opportunity to ensure regulatory and commercial outcomes are aligned with good engineering practice. This focus should be sufficiently detailed to cover off areas where control strategies may overlap and also encourage investments to ensure appropriate frequency control ongoing.

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

   No.

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

   Hydro Tasmania believes the DigSilent report[2] articulates these impacts reasonably well.

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?**

   When generators move in and out of their dead bands, it can create frequency oscillations due to discontinuity of the magnitude of the gain response. Thus having a dead band with a step change in droop characteristics should be particularly discouraged due to the potential of exciting oscillations.

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?**

   The table includes USA Western Interconnected system experience; however a better reference could be the North American Electric Reliability Corporation (NERC) that coordinates balancing and frequency control activities between 4 interconnections in the USA:

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[2] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf

- Western
- Texas (ERCOT)
- Eastern
- Quebec

USA experience is particularly of interest because of the extensive reliance on AGC providing SFC (NERC's *Reliability Guidelines on Primary Frequency Control* is a useful reference document). USA governor dead bands are typically set at ±34mHz except for ERCOT where the setting has been tightened to ±17mHz. The document also provides information on targeted droop settings in four US interconnected areas.

It is noted that the performance criteria on AGC in the USA is called Control Performance Standards. The main emphasis is on assigning responsibility for control of interconnection frequency, measure the impact of AGC on the frequency error and limits unscheduled interconnector flows. USA operate AGC in tie-line bias control while Australia favours multiple instances of a single area control.

10. Mandatory primary frequency control.

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

Hydro Tasmania acknowledges the need for PFC and supports a market based framework for procurement of PFC. Market based approaches would provide incentives for participants to respond to ensure the efficient provision of this service.

Taking a mandatory approach introduces the issues of grandfathering and how to deal with existing plant that does not have PFC capability.

b. <u>What factors should be considered in the specification of a mandatory primary frequency control response?</u>

Primary frequency response can be provided by generators and power electronics converters. Characteristics and the specification for these services would be different. Power electronics provide delayed response compared to inertial response but their ramping can be very fast compared to conventional governors, and sustainability of service depends on the type of energy storage media used.

Consideration should be given in terms of the practicality to provide the required response, the sustainability and the speed of the response. Units which are not capable of providing the service due to design restrictions (e.g. no governor or installation is not practical) or performance restrictions (high wear costs, e.g. Kaplan turbines) should be excluded from the provision of these services.

It is important to recognise that PFC cannot restore the frequency to the rated value but it should bring the output inside the AGC band so AGC can restore the frequency to 50Hz.

Consideration of control priorities is important and it is suggested that the Rules should address the following:

- Outside a narrow AGC operation band (yet to be defined), the frequency control has the highest control priority
- Outside the AGC operation band AGC signals should be suspended
- Once the frequency is back within the AGC operation band, the focus is on keeping the frequency within this band.

Thus once the frequency is outside the AGC operation band its recommended that its action is temporarily suspended or the AGC gains are significantly reduced, or the governor intelligent summing junction logic is used to reject AGC signals opposing restoration of the frequency. Controllers that directly act against primary control action should be not be allowed.

c. <u>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?</u>

Initial response of hydro machines is always slower than that of the thermal generators, therefore AGC in hydro systems must react slower to avoid interference with PFC. With the increasing penetration of wind generation, the power system is lighter and has a lower initial response (that is the sum of inertial response and governor response), which increases RoCoF. This supports having an increased requirement for PFC via a market incentive framework. .

d. <u>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?</u>

Subject to appropriate market mechanisms, this is broadly acceptable for hydro generators, as they are rarely dispatched at full output due to associated loss of efficiency; however exceptions exist and include generation operation during water spill events. Hydro Tasmania would support the provision of nominal reserves but with the recognition that unusual operating conditions may occasionally occur that would require special provisions/exceptions.

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?

Hydro Tasmania supports a market based framework for procurement of PFC. Market based approaches would provide incentives for participants to respond to ensure the efficient provision of this service.

Contract payments may be simple to negotiate and organise, however they may be less dynamic than a market based approach.

12. Market based options for primary frequency control.

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

Hydro Tasmania has represented its view in the preceding paragraphs.

b. <u>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.</u>

Hydro Tasmania is supportive of this approach as highlighted in the preceding paragraphs.

c. <u>The establishment of a new primary regulating service to provide primary frequency control within the normal operating frequency band, separate from contingency FCAS.</u>

This is a similar approach to that used by NERC in the USA and it is assumed that it is based on separation of AGC and PFC responses to avoid interaction. AGC is likely to provide sufficient response within a narrow band (say ±0.05 Hz) and the primary frequency control is activated much earlier than at present resulting in improved quality of the frequency. However in this option the contingency FCAS requirements and unit trapeziums may need to be revised.

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?

Hydro Tasmania believes that DigSilent report[3] covers this matter reasonably well.

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?

Hydro Tasmania supports this initiative as it will allow regular monitoring and analysis of the frequency control performance and provide transparency.

b. What metrics should such frequency monitoring reports include?

Suggested metrics to include could be:

- Number of times NOFB was violated.
- Available FCAS vs dispatched FCAS for each category.
- ACE based reporting similar to NERC criteria in the USA.
- The number of incidents when generator output is in phase with the frequency.

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

FFR appears to specifically address capability of power electronics with the following characteristics:

- FFR is not a substitute for the inertia, however after initial time delay it has the capability to deliver more power than the inertial response.
- Limited energy storage capability – limited ability to sustain the output.
- Ability to modulate the output (continuously and not step change).
- Fast response needs to be traded against reliability of the trigger.
- Delivery of FFR can be affected by low voltages and controller priority to maximise delivery of reactive power (LVFRT).

It is interesting that fast/slow/delayed FCAS for FFR are specified as triangular (ramping) response, it should be noted that a two second FFR response (FFR2) may also provide a triangular response however power electronics can respond either as step change or as a continuously modulated signal.

Hydro Tasmania has observed that in a hydro system, FFR2 could significantly complement the response of hydro machines. Recent Hydro Tasmania experience indicates that FFR with a limited energy storage (400MWsec) can be shaped and supplemented by other sources to maximise R6 delivery. In the thermal plants at present a supply of fast FCAS is not limited however delivery of slow services has limited capability.

[3] https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf

A general observation is that FFR fits well with the capabilities of inverter connected sources with limited storage. The value of different services depends on the supply/demand balance and the timing of when these services become available.

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?

Hydro Tasmania is not yet convinced that a specific two second FFR service has greater value on its own, rather than when incorporated into an R6 framework. Hydro Tasmania considers that a new inertia service should be added recognising requirements of minimum system inertia. Considering ongoing reduction of synchronous generation, the market should incentivise retention of inertia providing sources.

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

In addition to batteries, new technology which combine a Statcom and a small sized energy storage (based on super-capacitors) are being developed. Combined voltage and frequency control may be more cost effective due to sharing some hardware (inverter).

18. Managing the frequency impacts of non-dispatchable capacity

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

The existing FCAS framework has created a number of gaps that allow a variety of interpretations which could lead to significant deterioration of the frequency. Although current AEMO assessments indicate that the frequency standards are complied with, there is a continuation of trends such as:

- Withdrawal of PFC within NOFB.
- Use of governor controllers to force reaching the energy target at the end of a Dispatch Interval ignoring frequency.
- Increasing generation forecast errors due to variability of renewable energy sources.
- Reduced system inertia.

This is resulting in further deterioration of system frequency performance. Early action is preferred to address trends that are leading to a deterioration of frequency.

b. <u>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?</u>

Both approaches need to be explored. Forecast errors increase regulation requirements and the cost of provision however additional regulation FCAS may also need to be available.

c. <u>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?</u>

Options Hydro Tasmania suggests could be considered are:

(1) Minimising forecast errors.
(2) Market sourcing of PFC.
(3) Market sourcing of inertial service.

19. Cost recovery arrangements.

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

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

Current cost recovery for FCAS contingency services is based on allocating the costs between participants proportionally to energy generated/consumed. This approach does not take into account that some units which are non-scheduled will still contribute to the overall response and this contribution is important.

Hydro Tasmania suggests that the AEMC should consider adjusting the framework for the provision of FCAS contingency services. Raise FCAS contingency service machines should not have to pay when they are enabled to provide raise contingency services. Adjusting the framework may provide the incentive for greater provision of FCAS contingency services in the market.

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?

Hydro Tasmania assumes that eventually the above services will become reflected by NEMDE constraints. System strength is a local constraint so it should be satisfied first and then followed by minimum inertia constraints. It is likely that the system strength may be a more limiting condition.

In the past the system benefited from the growth as each new unit was adding more rotating mass to the system so the system frequency was more stable with associated lower RoCoF. Now the approach is based on a minimum inertia concept which assumes that there is a limiting RoCoF value (initial or average, imposed by equipment immunity requirements for the coordination of under-frequency or anti-islanding protection settings). With this assumption, inertia provided at higher than minimum levels do not have a value, and as such it may be withdrawn. Hydro Tasmania believes that the best outcome would be to have a market sourcing of an inertial service.

This can also be achieved by having system constraints, with off market mechanisms that incentivise adding more inertia and system strength to relieve constraints especially those which limit inter-regional power transfers.

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

In Tasmania in some cases, local impact of fault level (system strength) may have significant impact on the location of additional inertia thus fault level should be optimised first. Any additional inertia requirements (bith from a security and a market benefits perspective) can then be optimised.