FREQUENCY CONTROL FRAMEWORKS REVIEW

Response to issues paper - December 2017

1. Executive summary

Stanwell welcomes the opportunity to provide comment on the Australian Energy Market Commission's (AEMC's) Frequency Control Frameworks Review Issues Paper (issues paper). We commend the AEMC on their holistic approach to considering frequency control and for their attendance and participation at the Australian Energy Market Operator's (AEMO's) Ancillary Services Technical Advisory Group (ASTAG) and other industry meetings. Stanwell also commends the AEMC for its collaborative approach demonstrated by the initiation of an industry Working Group.

This holistic approach requires consideration of both the relative benefits of different frameworks and the efficacy of implementation of those frameworks. Stanwell, through participation in the ASTAG process and review of work undertaken by AEMO and other participants, considers that there is an emerging consensus that the existing framework implementation can be significantly improved at relatively low cost. While this does not preclude changes to the frameworks it will be important to separate the benefits of improvement from the benefits of replacement.

Stanwell has been involved in the ASTAG process from its inception and while we note the wider frequency distribution, it has not been demonstrated that the problem can not be significantly resolved simply by enabling a more appropriate volume of regulation Frequency Control Ancillary Services (FCAS) and fixing the settings in AEMO's Automatic Governor Control (AGC) system. There is clear evidence that AEMO is not procuring enough regulation FCAS and that the AGC settings (especially with respect to Tasmania) need urgent review.

Improving the dispatch forecast and creating a frequency forecast would also significantly assist with the problem. There is also the growing recognition of the need to transform "demand side response" into "demand side participation" (see section 5). Stanwell requests the AEMC urgently review how best to integrate distributed energy resources and other demand response into the market - if AEMO does not know about and/or cannot control these resources this will result in price volatility and increased FCAS requirements.

However, Stanwell accepts that additional or alternative frameworks may be required in order to manage issues not currently covered, or manage them more efficiently. Such markets should be defined so as to produce modern, technology-neutral approach to system management. If, as canvassed in the issues paper, primary frequency response is determined to be required, Stanwell is willing and able to participate in a new market for this service.

Stanwell welcomes the opportunity to discuss further this submission, please contact Jennifer Tarr on (07) 3228 4546 or Jennifer.Tarr@stanwell.com

2. Introduction

There has been an observed widening of the distribution of frequency within the frequency operating band[1]. At the same time there has been an observed reduction in the provision by generators of a free primary frequency response.

The potential solutions presented to date include mandating a primary frequency response, developing a market for primary frequency response and improving AEMO's implementation of the current frameworks including procuring more FCAS and updating AGC settings.

AEMO has identified that the frequency remains near the edge of the normal operating band for multiple dispatch periods (see Figure 1 and Figure 5). They have also, over time, reduced the base level of FCAS procurement (see Section 4) but must frequently procure additional FCAS due to time error (see Figure 4).

AEMO[2] and participants[3] have studied the relationship between enablement in Tasmania and frequency in the mainland. AEMO have also identified that 3-20% of the time the regulation component of AGC signals is contra to frequency[4].

There is also concern regarding AEMO's dispatch forecasting model, and increase in demand side response and their possible impact on frequency (see Section 5).

3. Frequency frameworks

Primary response

While Stanwell notes the wider frequency distribution, it has not been demonstrated that the problem can not be resolved simply by enabling more regulation Frequency Control Ancillary Services (FCAS) and fixing the settings in AEMO's Automatic Governor Control (AGC) system. There is clear evidence that AEMO is not procuring enough regulation FCAS and that the AGC settings (especially with respect to Tasmania) need urgent review.

If a primary frequency service[5] is determined to be required, Stanwell supports a new ancillary services market for this response. This will incentivise the continued installation of equipment to provide this service when it is required. The control systems at Stanwell's power stations have the capability to allow participation in this market.

The enablement of a primary frequency response is not costless and therefore the efficient provision should be through a market-based approach rather than mandatory provision. Mandatory provision will likely over-procure the service and will not distribute the costs in an efficient way to those generators best placed to manage them.

Procurement via a market mechanism would also allow consideration at the design level of the potentially competing signals from local frequency and AGC and the impact of providing primary response on causer pays calculations and compliance with dispatch targets.

The costs to provide a primary response relate to the opportunity costs in the energy market as well as the wear and tear on the unit due to the erratic nature of providing a frequency response. Figure 1 shows a generator smoothly following AGC targets until 16:47 when a contingency occurred. The frequency moved outside of the generator's deadband[6] and as a result the generator provided a primary response from 16:47 to around 16:56 when the frequency began to recover. The rapid increase and decrease in energy output during this period would have caused additional stresses on the machine, and therefore greater fuel and maintenance costs, compared to the smooth output it exhibits when following AGC targets. In addition, when the frequency had returned, the generator was faced with the opportunity cost of producing significantly less energy than its target.

[1] While the distribution is widening, it is unclear whether the distribution of the rate of change of frequency has also changed. Stanwell requested this information at the November 2017 ASTAG.
[2] Page 34, Issues Paper
[3] Regulation FCAS Report 1, pdView, September 2017
[4] Page 22, Review of Frequency Control Performance in the NEM under Normal Operating Conditions, Final Report, September 2017
[5] Stanwell has adopted the terminology utilised by the AEMC, however consider that detailed specification of that "primary response" is should be a pre-requisite of further market design work.
[6] Or perhaps this generator was enabled to provide a contingency response

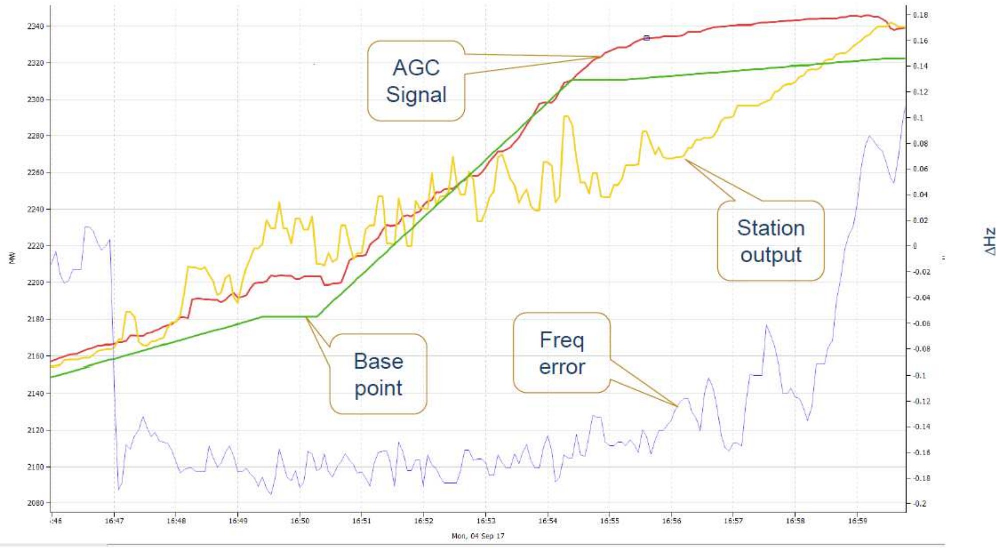

Figure 1: Comparison of generator following frequency versus AGC[7]

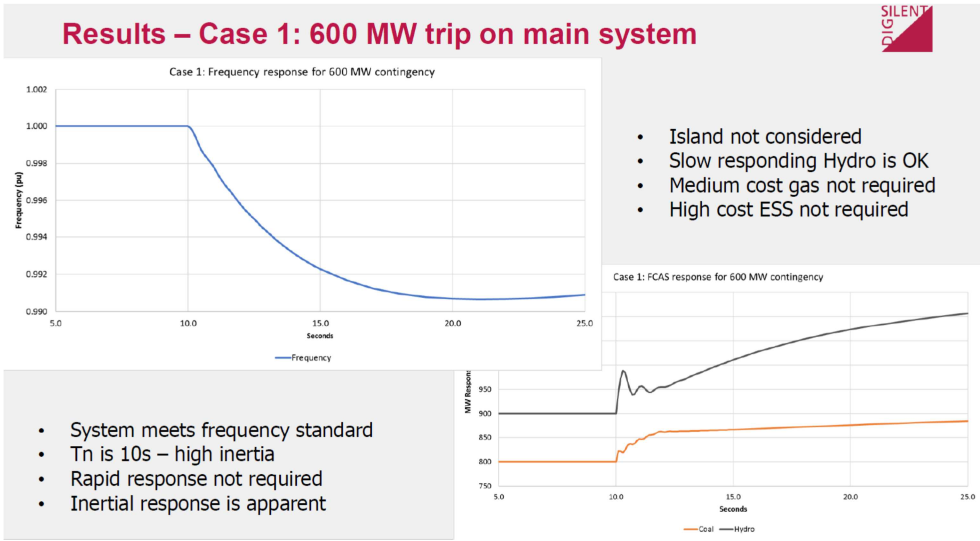

Figure 2: Example enablement given worst forecast contingency in high inertia system[8]

Structure of ancillary services markets

It appears that with the increased penetration of non synchronous generators (and the resulting reduction in inertia due to retirement of traditional generators) that very fast frequency response must be incentivised. However, even a new "very fast" frequency market to sit amongst the existing fast, slow and delayed frequency markets may not be the best outcome.

Each generator and each technology provides a different frequency response over a different time period at a different cost. A modern approach to frequency control might therefore be to forecast, in real time, frequency outcomes given a contingency and to enable only those generators that are capable of restoring the frequency at the cheapest cost.

This may mean in some circumstances when there is a high amount of inertia online, that the generators enabled are cheap, slow acting services. An example of this nature is shown in Figure 2.

At other times, when a very fast contingency response may be required, the most expensive, fastest acting combination of services would be enabled. An example of this nature is shown in

[7] Slide 11, AEMO, NEM Frequency Performance, presentation to ASTAG, November 2017

[8] Slide 15, DIgSILENT, Market Mechanisms for Frequency Control, 16th Wind Integration Workshop, Berlin, October 2017

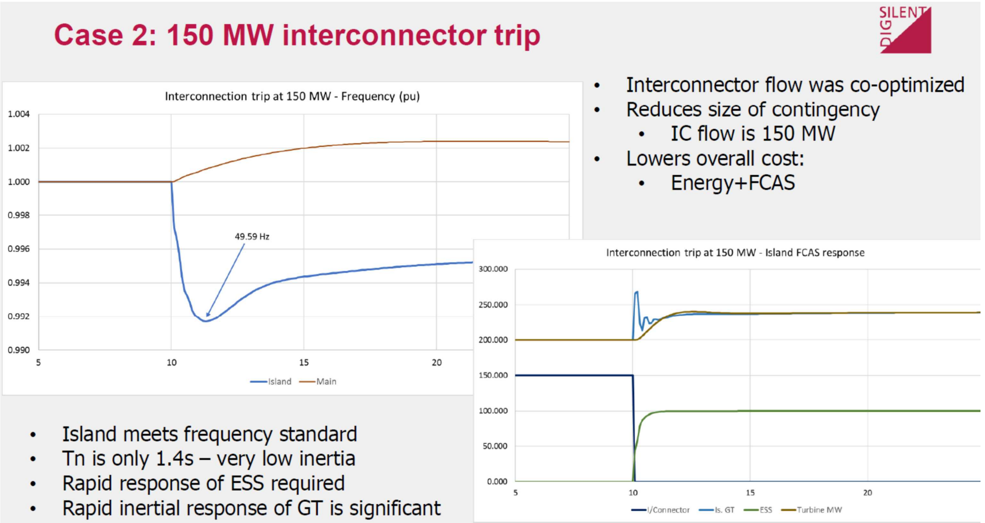

Figure 3.

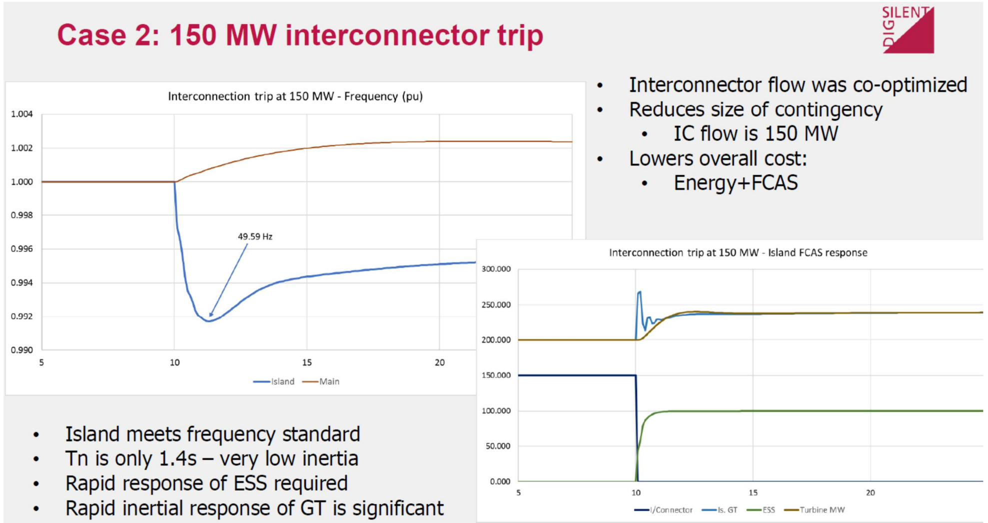

Figure 3: Example enablement given worst forecast contingency in low inertia system[9]

This technology-neutral approach would likely result in the most efficient provision of services. It also avoids relying on the problematic assumption that all providers of FCAS in each market are providing the same response.

4. AEMO's Automatic Generation Control (AGC) system

AGC settings

AEMO has demonstrated the importance of the settings of their AGC system and NEMDE in affecting frequency outcomes. When AEMO identified that the AGC system was contributing to frequency oscillations in Tasmania, AEMO de-tuned the system to make it less responsive to frequency deviations[10]. When AEMO identified that periods of prolonged frequency deviations coincided with a large portion of regulation enablement from Tasmania, AEMO constrained NEM-DE to enable less regulation FCAS from Tasmania[11]. These changes, in response to AEMO's

[9] Ibid
[10] Page 34, Issues Paper
[11] Page 34, Issues Paper

observation and analysis, appear to have had an immediate, significant and positive effect on the management of frequency.

However, even despite the recent improvements we observe that the frequency sometimes continues to persist for several minutes at the edges of the normal operating frequency band. This implies that the AGC regulation service is still not working as expected. When working properly, the AGC system should return frequency to 50Hz a lot faster than the several minutes it often takes.

Stanwell makes the following suggestions for areas of investigation

1. Restore historical levels of regulation enablement
2. Understand and improve the interaction between mainland and Tasmanian AGC systems. It may be that Tasmanian units are not like-for-like alternatives to mainland units when attempting to maintain the frequency on the mainland under current AEMO settings. pdView's work[12] shows examples where Tasmanian units were enabled to provide the majority of regulation raise services but received only small targets compared to enabled mainland units. This work also indicates that when Tasmanian units are enabled for a large proportion of regulating services the mainland frequency quickly deteriorates and does not recover until time error constraints require a much greater volume from the mainland.
3. Add real time metrics and alerts for non-conformance. Remove non-conforming units from dispatch of regulation.
4. Constrain regulation enablement from ramping units
5. Prevent regulation units that should be following AGC targets for frequency regulation from responding directly to frequency

Amount of regulation enabled

Figure 4 displays the actual mainland raise regulation enabled by AEMO since 2016. It shows that although the standard raise regulation requirement is 130MW, AEMO must frequently procure additional raise regulation – sometimes well in excess of the standard 130MW. Stanwell understands that this occurs when the frequency has been away from 50Hz for long enough for the time error to accumulate to a point where it triggers the procurement of additional raise regulation. The chart implies that time error is accumulating frequently.

[12] Regulation FCAS Report 1, pdView, September 2017

Figure 5 shows an example of this concept. The purple line is the regulation enabled. The light blue line is the difference between actual frequency and the target frequency[13]. The red line is the underlying regulation FCAS target. The green line is the actual amount of regulation FCAS dispatched, taking into account ramping limits and smoothing. The chart shows a frequency disturbance at around 16:26. In response, the regulation dispatched quickly increases to raise the frequency. From around 16:29, the regulation dispatched equals the maximum enablement volume so no more can be dispatched. Because of this the frequency remains 0.15Hz below target for 6 minutes until 16:35 when the time error has accumulated to a point that triggers the additional enablement of regulation services.

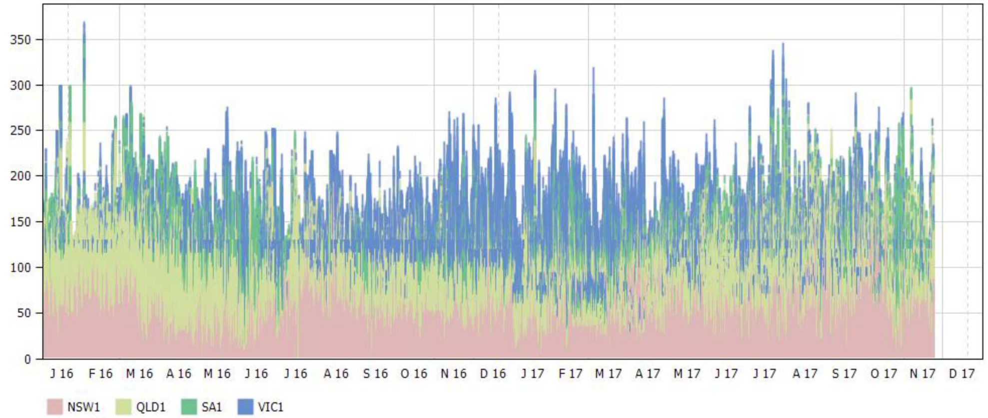

Figure 4: 2016-present, Actual NEM-wide raise regulation enablement[14]

[13] Target frequency is nominally 50Hz, however as time error accumulates AEMO may introduce an offset to the target in order to gradually reduce the time error.
[14] AEMO, NEM Frequency Performance, presentation to ASTAG, November 2017

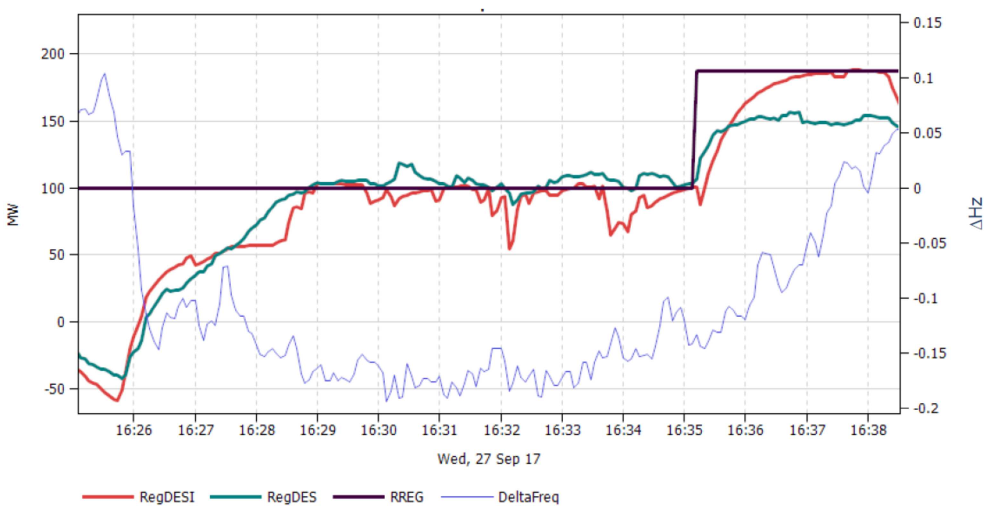

Figure 5: Raise regulation example[15]

Stanwell understands that in 2001 an initial review of the amount of regulation FCAS that was required for the NEM was +/-250MW. This assumed no "free" response as AEMO specifically wanted to encourage the FCAS market. Later AEMO chose to reduce the amount procured to +/-130MW given there was so much "free" response available. If, as indicated by DIgSILENT, the "free" response is reduced and frequency persists away from 50Hz for several minutes, it appears that AEMO must urgently review the amount of regulation FCAS enabled. The apparent under-procurement of regulating FCAS in response to evolving market fundamentals is not an issue with the frequency control frameworks, but with their implementation.

[15] Ibid

5. Forecasting

As noted by the AEMC, demand forecasts are used by AEMO to dispatch the appropriate amount of scheduled generation. If forecasts are inaccurate then the incorrect amount of scheduled generation is dispatched. This results in a supply/demand imbalance which requires frequency services to rectify. Therefore the better the forecast, the less frequency services are required.

Wind and large-scale solar forecasts

The AEMC has analysed the size of forecast errors related to intermittent generation. Due to geographic diversity, on a NEM-wide basis, 5 minutes ahead, these appear to be relatively small as shown in Figure 6 below. While Stanwell notes that averaging can obscure important data, this analysis in conjunction with that presented by CS Energy indicate that forecasting of wind output is not the dominant contributor to forecast errors

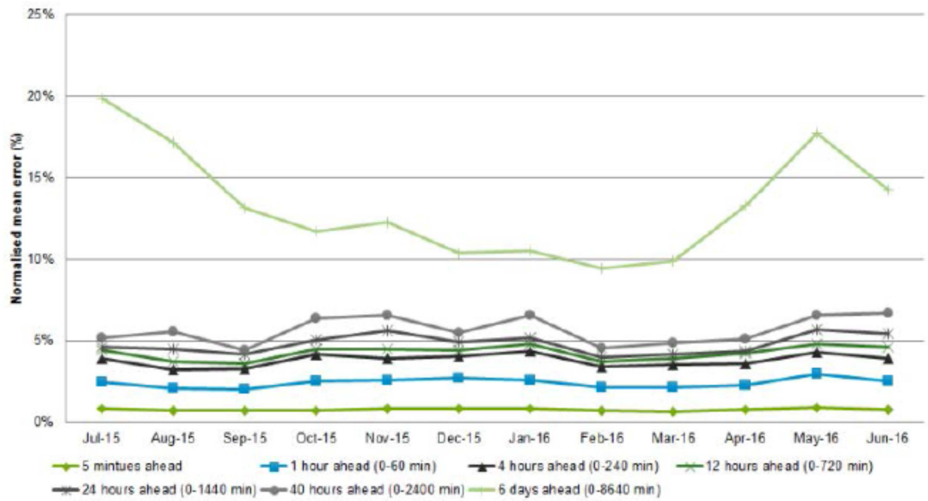

Figure 6: NEM-wide variations between forecast and actual wind output (page 52, issues paper)

The AEMC poses questions relating to large-scale solar forecasting. We encourage the AEMC to obtain information on AEMO's large scale solar forecasting model and its accuracy to inform all market participants. This information will become especially important in the future as large-scale solar capacity increases. However, Stanwell understands that CS Energy assessed the change in output from large-scale solar facilities and found that their output does not vary as much as expected[16].

Stanwell notes that AEMO's forecasts of wind and large-scale solar facilities are relatively new and thus have benefited from the latest techniques in forecasting research. We also note that there is significant industry interest and engagement in the design details and inputs of these forecasts. This is because these forecasts are directly linked to wind and solar participants' financial returns through AEMO's causer pays procedure. As a result, it appears that there need be little regulatory concern on the accuracy or oversight of these forecasts.

Demand forecasts

The AEMC is concerned about the future impact on dispatch and frequency of home energy management systems and distributed networks of batteries acting in unison. Stanwell shares these concerns and considers that an urgent review of the best way to engage "demand side participation" is required.

Demand side *participation* is distinct and far more beneficial than demand side *response.* Demand side participation is when the intentions and price sensitivities of demand are understood by AEMO and can be properly incorporated into forecasts, dispatch and frequency requirements. Demand side response on the other hand occurs when sophisticated loads (individually or in aggregate) react in an un-forecast manner, contributing to price volatility and frequency deviations. Although the AEMC has expressed concern regarding distributed sources of demand response, Stanwell also has significant concerns about the impact of individual, sophisticated large customers behaving in a similar way.

Last summer, Stanwell observed the un-forecast actions of several sophisticated large customers directly affecting market operation. We observed times when in excess of 300MW of un-forecast demand reduction occurred within a dispatch interval. This action coincided with AEMO overriding the "Aggregate Dispatch Error" value in order to help manage frequency.

Previous rule change and market review processes have canvassed the effects of some examples of this behaviour on energy price and market efficiency; however the impact on system control has received little attention to date. In a market experiencing greater frequency variation, measures to remove or reduce such avoidable system shocks may provide significant benefit to consumers. Providing

[16] Page 6-13, CS Energy submission to AEMC's Frequency Operating Standard Stage 1 Review

AEMO with sufficient visibility of demand side resources in order to incorporate their effects into the dispatch process would be expected to significantly decrease their adverse impacts on system operation, while retaining the benefits sought by the operators of those resources. Alternatively, AEMO must increase their procurement of control services to provide an appropriate buffer to account for these un-forecast actions.

Dispatch forecasts

Systemic inaccuracy of AEMO's dispatch forecast can also affect frequency performance. The heat map shown in Figure 7 below shows the average mainland frequency per five-minute interval for 2016. Patterns in the data imply systemic forecast errors resulting in over or under frequency events. For example, the horizontal lines close to midnight may relate to hot water switching and the evening red "unhappy mouth" that begins in April and ends in September may relate to issues associated with forecasting light switching, roll off of solar or the synchronisation of fast start generators to meet evening peak demand.

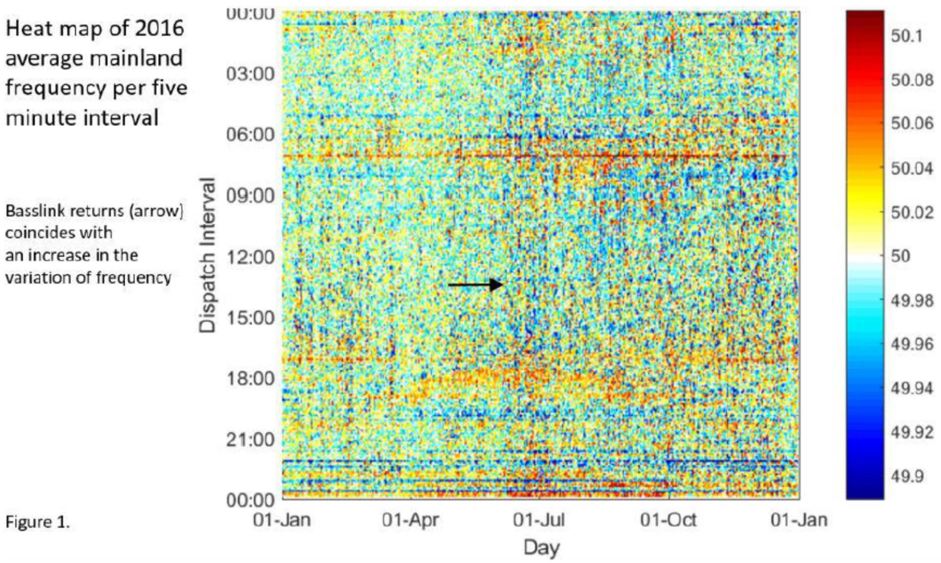

Figure 7: Average frequency 2016[17]

Patterns in the data imply that dispatch forecasting can be improved and this is consistent with the findings of the University of Wollongong[18]. pdView suggest that the addition of an intelligent learning algorithm which contains a feedback loop would eliminate these systemic errors and probably fix other systemic errors that are not observed by the eye. AEMO should also consider forecasting "frequency" separately and incorporating the frequency forecast into NEMDE. This would allow AEMO to dynamically procure the appropriate amount of regulation FCAS enabling better management of frequency and reduced costs to consumers.

Significant findings from the University of Wollongong include[19]

- "The report provides strong evidence that the current AEMO neural network model is not suited to accurately perform dispatch demand forecast."
- "The report finds that the type of neural network used by AEMO is a first generation neural network that is over 20 years old."
- "It is demonstrated and explained that the current model cannot deal with abnormal conditions that arise out of volatility, spikes, shocks, price responses, and any other situation which require the modelling of context for accurate predictions."
- "Much more appropriate methods have been developed in the years since the adoption of AEMO's current neural network model."

Stanwell considers that each of these reviews suggests potential improvements to existing systems which are likely to improve frequency distributions more rapidly, more cheaply and more robustly than something as drastic and costly as changing the frequency control framework.

[17] Figure 1, Regulation FCAS Report 1, pdView, 2017

[18] University of Wollongong, Evaluation of neural network models for AEMO's five minute electricity forecasting, 13th December 2016

[19] Executive Summary, Ibid

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