Ref: EPR0053

16 October 2017

Attention: Mr Ben Hiron
AEMC
ELECTRONICALLY SUBMITTED

Dear Mr Hiron

Review of the Frequency Operating Standard – Stage 1

CS Energy welcomes the opportunity to respond to the Stage 1 Draft Determination on the Panel's review of the Frequency Operating Standard ('FOS').

The proposals

Under the FOS, AEMO must keep the frequency within a band of +/-0.15Hz 99% of the time, for changes in load that are not contingencies. A contingency is the trip of a synchronous generating unit.

Whilst this standard has not been breached, AEMO has found that the performance over 2016 and early 2017 deteriorated, closer to the standard. AEMO believes the problem is generators widening their "dead bands" resulting in synchronous generators not automatically correcting frequency (which they call Primary Frequency Control 'PFC').

AEMO has advised the Panel the computer control system ('AGC') that dispatches regulation FCAS is unable to respond fast enough to manage deviations (in excess of 50MW in less than 30 seconds) from wind farms and solar PV fields, which are not contingencies under the existing Rules. They consider the demands from these generators will increase in the near term and these should be included in the definition of contingency.

For these reasons AEMO has advised the Panel to exclude deviations (in excess of 50MW in less than 30 seconds) within those it must cater for within +/-0.15Hz 99% of the time, so it can procure less Regulating FCAS (than it would have otherwise have done). The changes to the FOS apply from 7th November 2017.

Our response

Our response is technical in nature, with data analysis and references to our consultant's previous work.

In summary we do not agree the redefinition of the generation event (50MW over 30 seconds) is necessary.

Firstly, the current performance of Regulation FCAS is within the FOS for the Mainland[1].

[1] AEMO – AS-TAG

Secondly, it is not clear that the AGC Regulation system is incapable of managing frequency with the Normal Operating Frequency Band (NOFB) and cannot be improved to satisfy tomorrow's demands.

Thirdly, analysis indicates that these 50MW over 30 seconds are infrequent, can be accommodated in the existing FOS and would not require the purchase of more regulation services.

Instead we conclude demand for frequency regulating services from PV and wind generators over the 5 minute timeframe remains manageable. The deterioration in frequency appears to be, not as a result of the demand side, but rather the performance of the supply side.

A reduction in PFC would not in itself lead to a deterioration of frequency if the AGC Regulation service performed as intended.

CS Energy and its consultant PD View have investigated the AGC regulation system based on extensive modelling and analysis of historical AEMO four second data.

After completing this investigation, CS Energy considers the answer lies not in mandating primary frequency control, with tighter dead-band settings and changes to the FOS, but by improving the performance of the AGC Regulation system.

Our position is that the AGC Regulation system can manage sudden deviations from trajectories throughout the 5 minutes as long as it is properly administered, appropriately resourced and of high quality. Primary Frequency Control can remain for contingency response, dealing with unexpected contingencies. We explain this in Appendix 1.

The AGC system and Regulation FCAS service can be improved in the following areas:

a. quality of unit performance in response to signals, including updating of AGC systems to ensure that units which are not responding to AGC signals are not subsequently enabled for Regulation FCAS and avoid purchasing FCAS in excess of a unit's maximum availability;
b. improving the headroom for Regulation FCAS AGC signals at the start of the dispatch interval;
c. the operation of the two AGC systems and Basslink; and
d. increasing enabled amounts, not in response to accumulated time error but in response to frequency.

Further, using Contingency FCAS in lieu of Regulation FCAS as proposed by AEMO may dull marginal price incentives, exacerbating the problem.

The Regulation FCAS 'causer pays' calculation methodology, although not perfect, seeks to appropriately allocate the cost of Regulation FCAS to causers based on unit performance.

This contrasts with Contingency FCAS costs which are 'smeared' across all generators or consumers. All else being equal, these poor incentives will encourage decisions, at the margin, that deteriorate frequency and increase costs.

In the longer run, we consider, with the correct incentives placed on market participants, consumers will be better served by allowing the market to control frequency and in time, determining the FOS. Ideally, the <u>control of frequency would be decentralised and the market would determine the appropriate quantity (control of frequency) depending on the cost</u>. This trade off is suited to a market, with participants responding to marginal price signals, rather than a regulated agency, such as AEMO or the Panel. An approach to do this is explained in Appendix 2.

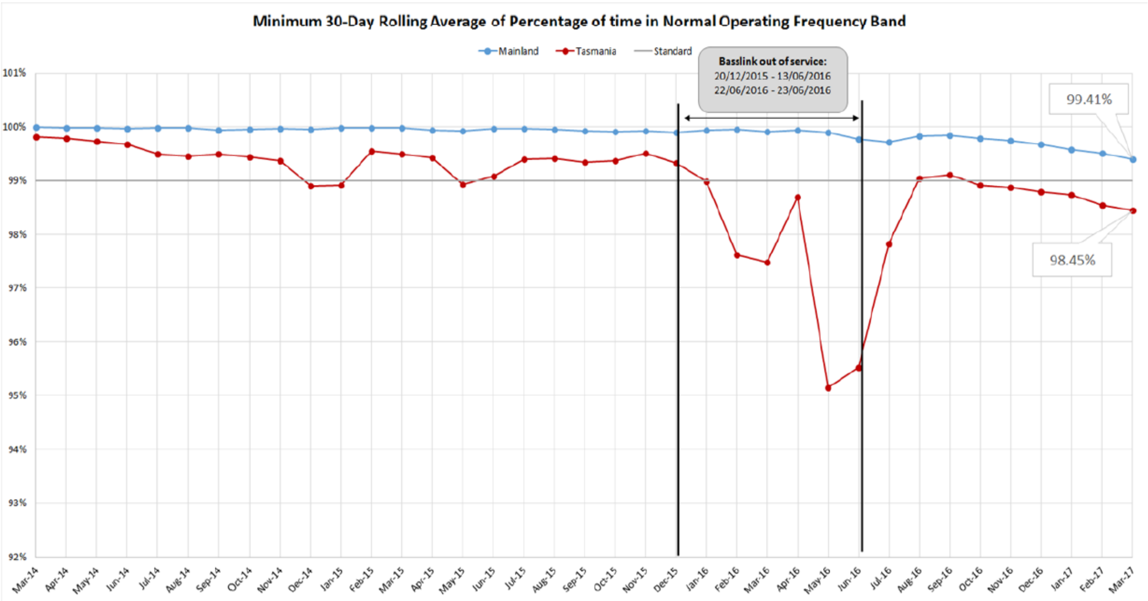
Stephen Hoult

Group Manager – Energy and Carbon
Enquiries: David Scott
Telephone 07 3854 7440

Appendix 1: Comments on the draft FOS, AGC

We do not agree the redefinition of the generation event (50MW over 30 seconds) is necessary.

Firstly, the current performance of Regulation FCAS is within the FOS for the Mainland[2]. This is in spite of a series of issues with management of the AGC system and procurement of Regulation FCAS, (which we explain in the submission and through attached reports from our consultant, PD View).



Source: AEMO

Secondly, it is not clear that the AGC Regulation system is incapable of managing frequency within the Normal Operating Frequency Band (NOFB) and cannot be improved to satisfy tomorrow's demands. AEMO has not provided evidence of the performance of the AGC system to the Panel, AEMC and Industry.

Thirdly, although AEMO suggests changes in load from PV and wind farms are, and will, move faster than the AGC system can cope with, it has not provided the data to prove this. Our analysis with PD View indicates that these 50MW over 30 seconds are infrequent, can be accommodated in the existing FOS and would not require the purchase of significantly more regulation services.

Instead we conclude demand for frequency regulating services from PV and wind generators over the 5 minute timeframe remains manageable. The deterioration in frequency appears to be, not as a result of the demand side, but rather the performance of the supply side.

Whilst AEMO has found the 'Gradual decline in primary frequency response is the root cause of the frequency performance degradation[3]', this would not result in a wider

[2] AEMO – AS-TAG
[3] AEMO, SUMMARY OF DIGSILENT INVESTIGATION INTO FREQEUNCY CONTROL IN THE NEM UNDER NORMAL CONDITIONS Aug 2017

standard deviation of frequency if the AGC Regulation service performed as AEMO expected.

Whether or not the reduction in PFC is as a result of the widening of dead-bands or a reduction in reserve 'headroom' of synchronous units providing governor control, or more probably both, is not something CS Energy has determined[4].

AEMO's focus has been on restoring PFC, possibly by mandating the service or through other mechanisms, such as changing the FOS, service specifications and definitions of events these services must accommodate. Instead, CS Energy believes the answer lies in improving the performance of the AGC Regulation system.

The AGC Regulation system can manage sudden deviations from trajectories throughout the 5 minutes as long as it is properly administered, appropriately resourced and of high quality. Primary Frequency Control can remain for contingency response, dealing with unexpected contingencies.

The studies we have performed with PD View[5] suggest the standard deviation of frequency is more of a function of deficiencies in operation of the AGC Regulation system (supply), including too little regulation (effective enablement) and the two independent AGC systems interoperating poorly. The additional demands on the power system from PV and wind generation do not yet seem to be material.

Further to CS Energy's earlier work with PD View, the reports we attach to this submission, CS Energy and PD View investigated the nature of the problem described by AEMO (sub 30 second changes in generation) and an inability of the AGC Regulation FCAS to respond.

We found:

1. Sub 30 second deviations greater than 50MW, do occur for PV and wind farms, but the probability of these events is not high;
2. It is likely the sub 30 second deviations greater than 50MW can be accommodated within the existing FOS 1% allowance outside the NOFB;
3. There appears no reason to change the FOS, nor to redefine the generation event to account for these occurrences;
4. At such a low probability, the 50MW deviations over 30 seconds:
    a. do not appear to be a primary cause of poor frequency; and
    b. do not require the purchase of more Regulation or Contingency Services.
5. Deterioration of frequency may have AGC Regulation service struggling to cope after the withdrawal of synchronous generator governor control (PFC):
    a. it is unclear the reduction in PFC is as a result of the widening of dead-bands or a reduction in reserve 'headroom' of synchronous units providing governor control, or possibly both.
6. AGC system and Regulation FCAS can be improved in the following areas;
    a. quality of unit performance in response to signal;
    b. improving the headroom for AGC signals;
    c. the operation of the two AGC systems and Basslink; and
    d. increasing enabled amounts, not in response to accumulated time error, but in response to frequency.

[4]PD View did not attempt any correlation between frequency and reserve, inertia or dead band settings. At this stage it cannot be stated one way or the other how much of an impact changes to these variables had on frequency.
[5] PD View - An analysis of AGC relative effectiveness of Tasmania versus Mainland, and station performance

Investigation into solar PV and wind farms events

Whilst changing loads of utility solar PV and wind farms may occur over 30 seconds, AEMO itself highlights that larger deviations occur over 5 minutes[6], which is well within the timeframe Regulation FCAS expected to perform.

CS Energy considers variability of solar PV and wind generation are not contingencies but rather deviations from 5 minute forecasts or trajectories. This is an important point, because a unit contingency or loss on synchronism, such as a trip of Kogan Creek generator is something that can be minimised through good engineering and operating practices, but cannot be forecast within the five minutes: notwithstanding there may be some data that suggests the unit is becoming unstable (which would normally result in some measures taken by the operator, such as trying to reduce load to prevent a trip).

On the other hand a rapid change in load of a wind farm or a solar PV field can be forecast (or output controlled to match the forecast) should the incentive be placed on the operator to do so. For example the operator could evaluate wind speed data across the farm to improve their forecast and moderate load change on the turbines through control measures to more closely match the 5 minute trajectory. For a solar PV field, the operator could assess cloud cover as it moves across the vicinity and predict its output and curtail output marginally to mitigate the ramp.

It is our view that changes in load of solar PV and wind generators does not satisfy the new definition of generation event, which is "*a sudden, unexpected and significant increase or decrease in the generation of one or more generating systems of more than 50MW within a period of 30 seconds or less*".

The key adjective is 'unexpected' which is not true of changes in load from variable generators. We would argue that it is to be expected and can, at least to some extent be forecast or at least controlled by the operator. We suggest AEMO would not be compliant with the FOS should it allow changes in load of solar PV and wind generators to move frequency outside the NOFB for more than 1% of the time.

This leads to the question of whether these 'events' will lead to a breach of the FOS.

On the one hand AEMO states in its advice[7] that:

"*Such credible generation events may only occur once or twice a year, which is similar to the probability to the trip of a synchronous unit*".

Yet on the other AEMO says that:[8]

"*AEMO may be required to purchase additional regulation FCAS in order to meet the FOS, specifically AEMO would be obligated to try to maintain frequency in the normal operating frequency band for these events*".

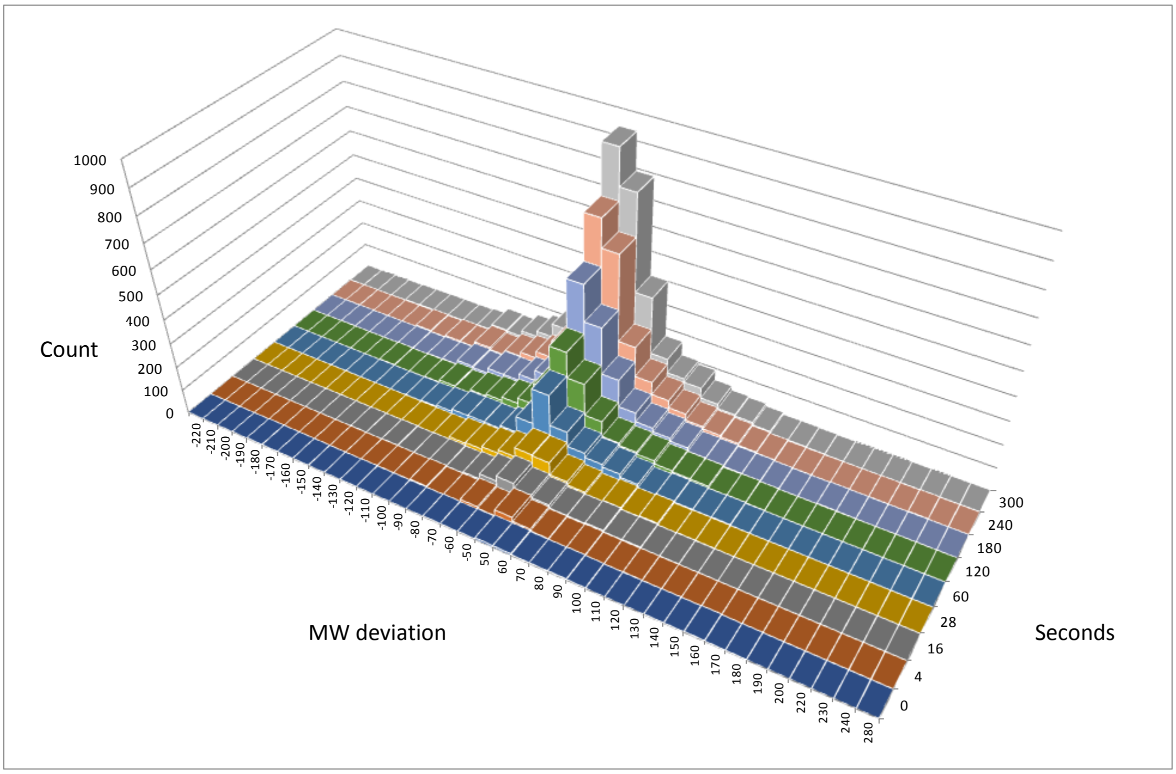
It is incoherent for AEMO on the one hand to liken the events to contingency, yet on the other state they would need to buy regulation FCAS to satisfy the FOS. The FOS allows excursions from the NOFB for an allowed percentage of time.

[6] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.8
[7] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.10
[8] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.10

CS Energy requested PD View analyse the performance of large wind farms and solar PV fields, using 4 second data from AEMO.

The following 3D Aerial chart and table present, for 2016 and 2017 combined (to July 2017 incl.) the number of seconds or less for a change in MW, with the change in MW truncated to the nearest 10MW. The count is cumulative, excluding 0 second events. For example there were 80 events where a wind farm or utility PV changed load between 50 to 60MW in fewer than 28 seconds. This includes both the 31 events that were sub 16 secs and the 13 that were sub 4 secs.

Zero seconds occurs over a four second period where either MW reading is exactly zero. Some of these are real and some of them may be bad data (flagged as good in the data set). The zero second events have been identified separately as, just like any other generator these power stations have occasional ‘trips’ or faults. For example Nyngan suffered far more of these in 2015 than in later years, probably due to a control system error or fault.

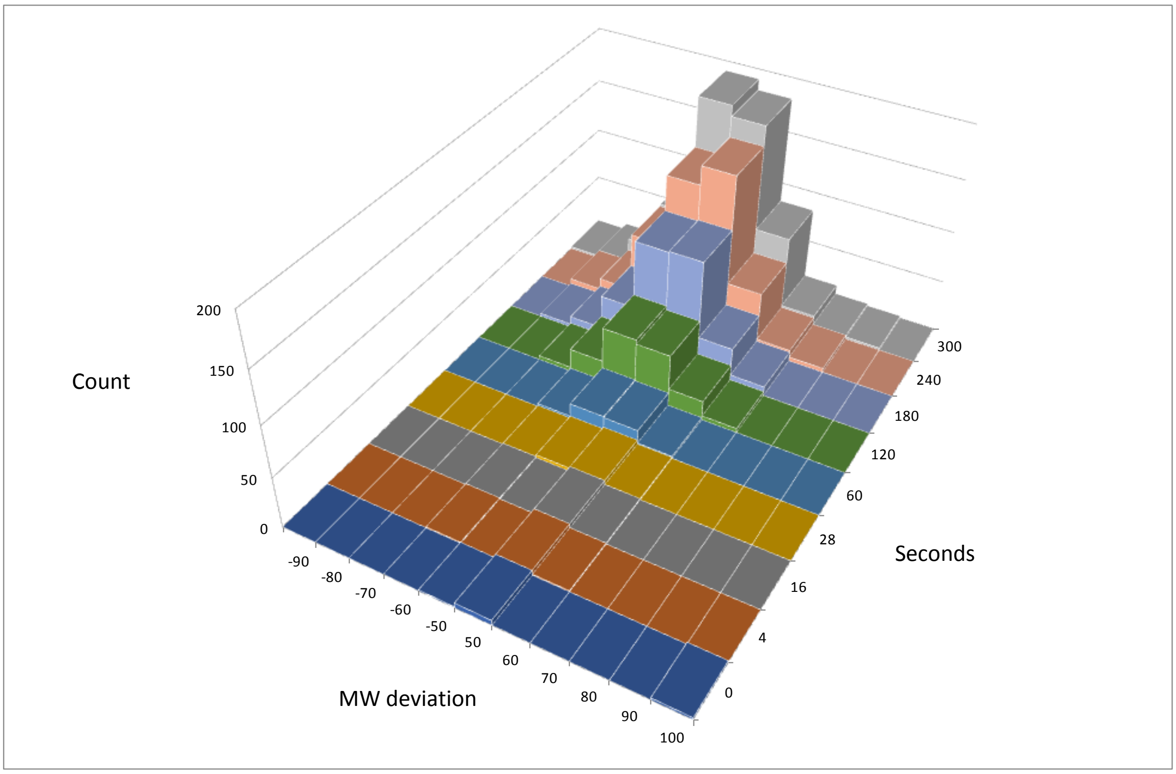


It can be observed from these figures that large events over short periods are relatively rare and low probability.

By contrast there are larger changes in generation over longer periods, although these remain relatively immaterial.

	0	4	16	28	60	120	180	240	300	Grand Total
-220									1	1
-210								1	1	1
-200							1	1	1	1
-190									1	1
-180	2								3	5
-170	1								4	5
-160	1					2	2	6	6	16
-150	1							2	5	8
-140			1	1	1	1	3	9	9	19
-130					1	3	5	7	10	26
-120	1	1	2	2	4	14	24	31	35	112
-110		1	1	1	10	10	18	22	31	91
-100		1	1	1	20	25	41	44	57	190
-90		4	4	12	22	33	41	63	81	259
-80			1	16	21	48	69	92	139	386
-70	2		6	28	34	72	113	166	244	665
-60	1	11	29	44	103	165	240	392	475	1460
-50	2	4	51	84	253	352	550	737	935	2968
50	8	31	31	80	124	245	401	622	790	2332
60	7	13	20	27	61	112	208	269	401	1118
70	3	5	7	13	43	47	93	144	166	521
80	3	2	6	6	31	37	55	92	107	338
90	4	4	9	10	17	29	40	61	92	266
100	2	1	3	4	4	16	27	34	49	139
110			4	8	8	12	13	24	30	98
120		1	1	1	4	11	11	18	25	72
130			1	2	3	3	6	10	14	39
140	1			1	4	5	5	6	6	27
150	1				1	2	2	2	5	13
160	3							1	3	7
170	1								1	2
180	1						2	2	2	3
190							1	1	1	1
200								1	1	1
220									1	1
230								2	2	2
240									1	1
280									1	1
Total	**45**	**79**	**176**	**336**	**766**	**1243**	**1971**	**2858**	**3722**	**11196**

The following 3D Aerial chart and table present, the same data for utility PV only.



	0	4	16	28	60	120	180	240	300	Grand Total
-90									2	2
-80							3	8	8	19
-70						4	11	19	31	65
-60		1	1	1	3	23	44	76	78	227
-50	1			3	16	57	110	144	191	522
50	5	5	5	5	15	53	111	162	181	542
60		1	1	1	2	19	36	58	82	200
70						4	9	11	13	37
80								4	4	8
90									2	2
100	2									2
Total	8	7	7	10	36	160	324	482	592	1626

Given this information provided by PD View, showing events in excess of 50MW in under 30 seconds are infrequent, the likely scenario is that these events can be accommodated by the existing 1% allowance for frequency to deviate outside the NOFB.

It appears to us that these events are not immediately requiring the purchase of additional regulation services, irrespective of the question of whether the AGC system could accommodate them.

This opposes AEMO's statement[9]:

"*as variable generators are built in increasing number and size, this will increase the overall frequency and magnitude of events involving rapid changes in output. This will drive up the amount of regulation FCAS to deal with these events*"

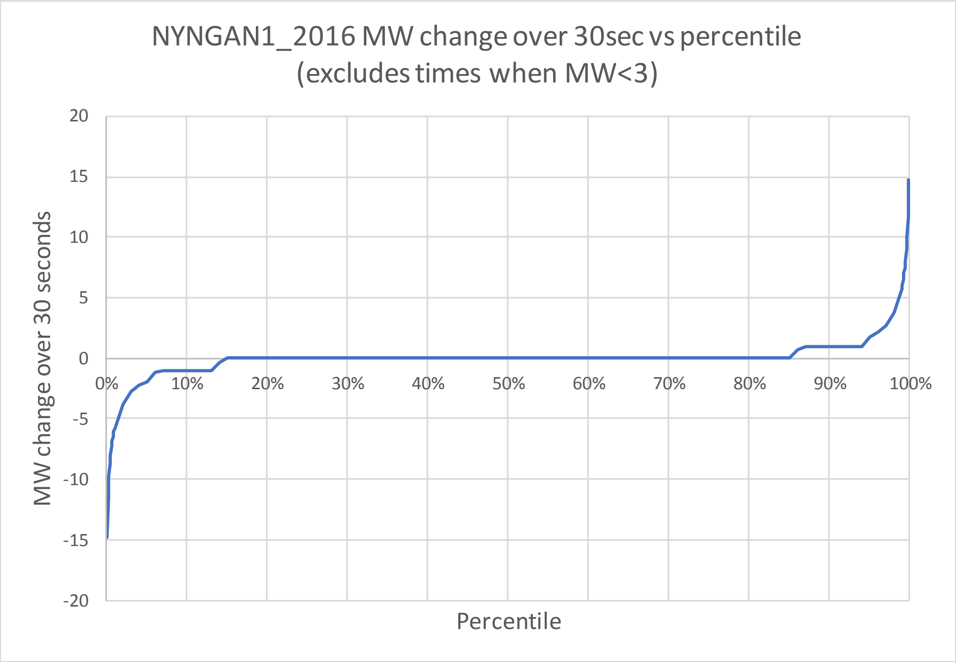
[9] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.10

It is also recognised by AEMO[10] :

"*For completeness, AEMO notes that with the proposed change, it is possible that there may be an increase in the frequency of use of contingency FCAS, which could conceivably result in providers eventually changing bids to compensate for additional wear and tear. However it is expected that this would be minor compared with the cost of additional regulation FCAS procurement"*

Whilst these events may have a higher probability than generator trips, PD View's findings suggest that they will remain infrequent and therefore if contingency FCAS was used to satisfy these events, there will not be a material change to the services.

For example, the following figure presents the largest PV field, Nyngan in NSW. This facility is 101MW. It excludes night as it only includes periods when generating. There is an extremely low percentile where deviations are in excess of 15MW in under 30seconds.



AEMO summarises its position as follows[11]:

"AEMO regards that this is an important change, as these kinds of generation events are already occurring, and are anticipated to become larger and more frequent as committed solar farms are commissioned. Some of these may be in service by summer of 2017-18."

After completing analysis of 4 second data, we do not agree it is important to change the FOS. Events may already be occurring, and more may occur in the future, but events greater than 50 MW in under 30 seconds appear to be infrequent.

Longer events are higher probability than sub 30 second events, yet remain relatively infrequent and of such a size that they should be suitable for the AGC system to cope with. That the AGC system isn't coping is another matter that needs to be addressed.

For completeness, a 400MW wind farm is shown below.

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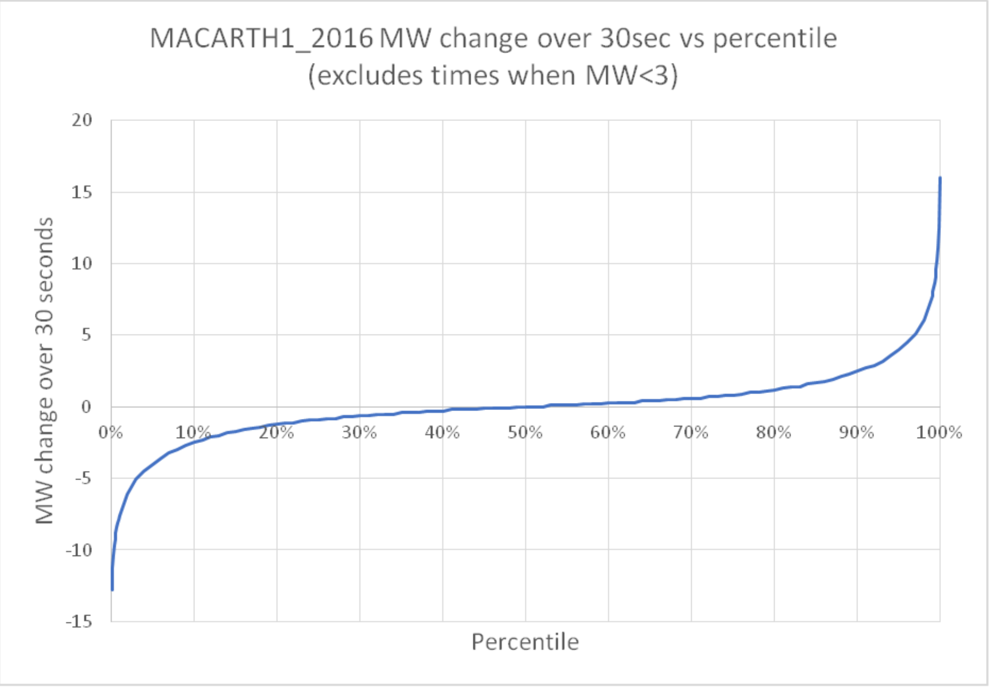
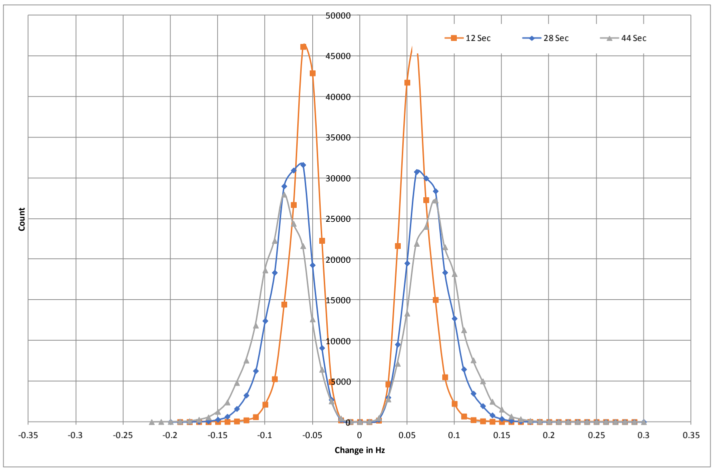
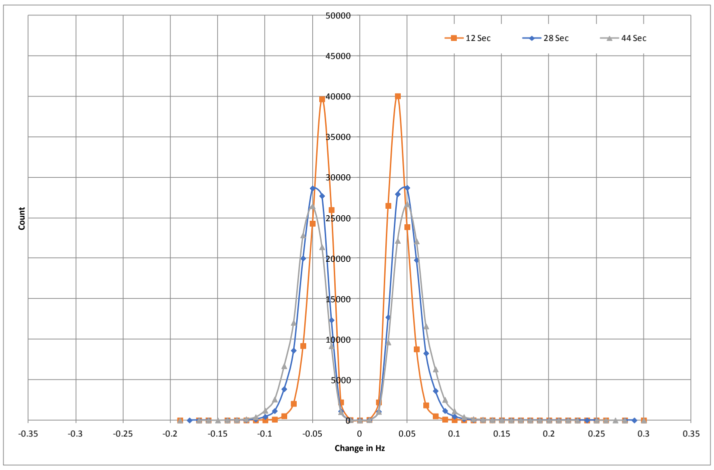
[10] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.11
[11] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.11





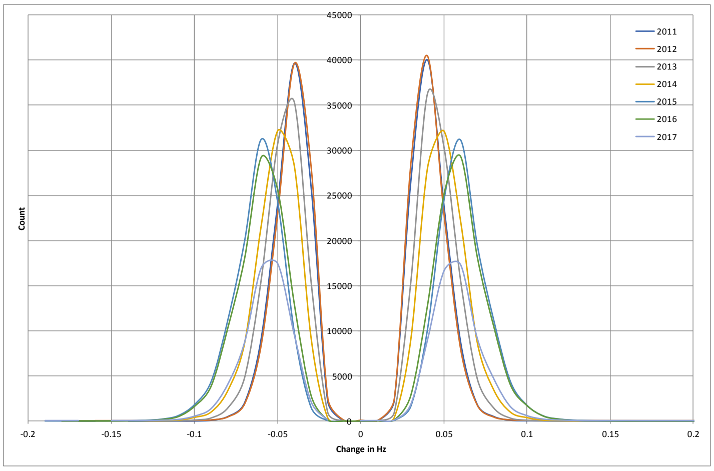


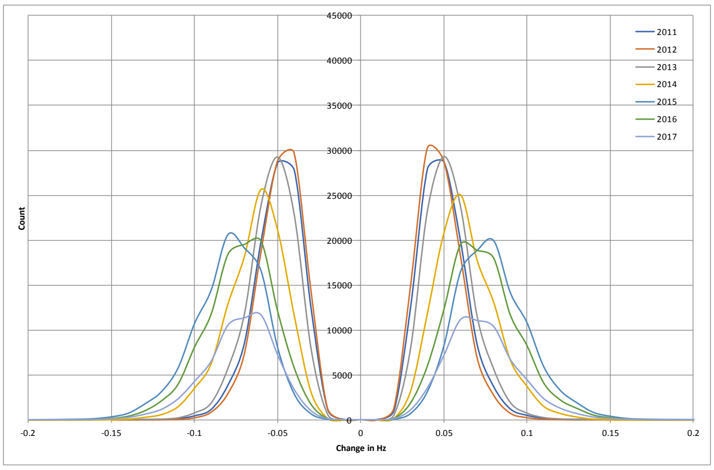
PD View also investigated frequency control in the sub 30 second timeframe, compared to other periods.

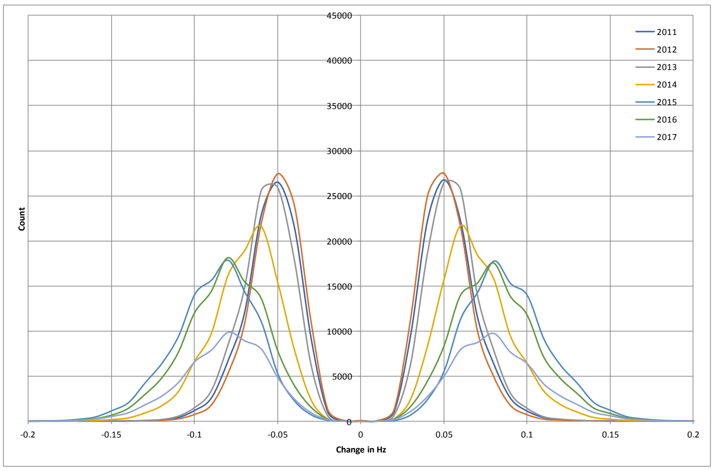
The figures show the number of changes in frequency in fewer than 12, 28 and 44 seconds, by size of the change in frequency.

The top figure is 2016 and 2017 (Jan –Jul inclusive) combined. The bottom is 2011.

What is interesting is that, although the changes in frequency have grown under all periods, the longer time periods show a wider distribution. This is counter intuitive, given that frequency control services, such as AGC regulation, should be restoring frequency over the longer time period closer to 50Hz.







The figures to the left show similar data, yet in this instance each chart represents the time period.

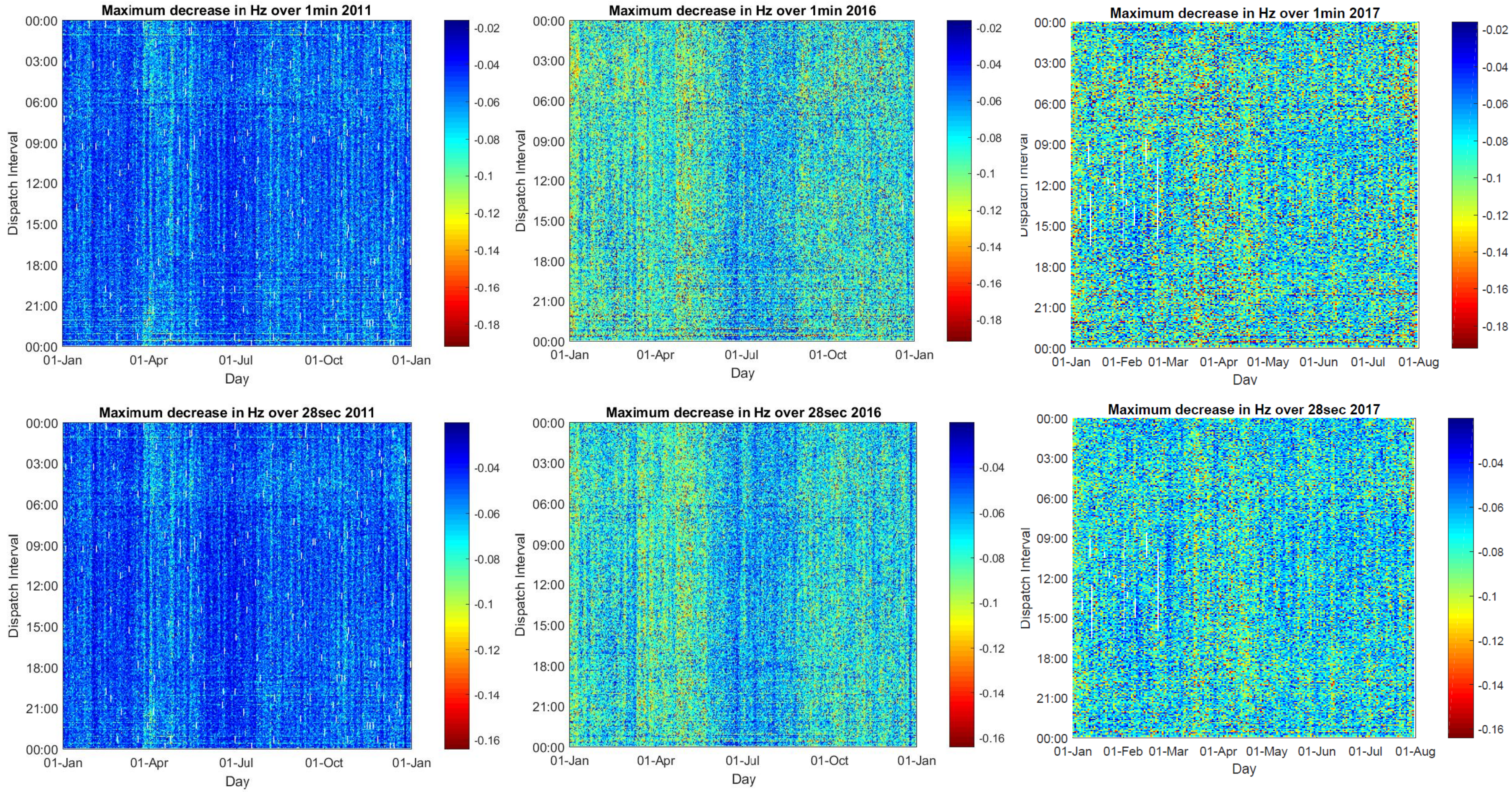
The top chart is 12 seconds, the middle chart 28 seconds and the bottom chart 44 seconds.

The problem in controlling frequency may not be a sub 30 second issue: it persists for longer and could therefore be related to the supply of frequency response instead of more demand for response (such as from deviations in load from wind farms and utility PV fields or other generators and loads).

On the following page, PD View has presented the maximum change (increase or decrease) in frequency over two different timeframes (under 28 secs and under 1min), over 3 different sample years.

Whilst there is a marked increase in the size of deviations since 2011, (in 2017 the blue is no longer as prevalent as it was in 2011), it can be noted that larger deviations (red) are regular, yet the key point is that there is not much difference between the two time periods, 28 secs or 1 min.

This further supports the hypothesis that problems are related to the supply of frequency response and not more demand for response (such as deviations from wind farms and utility PV fields).


Maximum decrease in Hz over 1min 2011
Maximum decrease in Hz over 1min 2016
Maximum decrease in Hz over 1min 2017
Maximum decrease in Hz over 28sec 2011
Maximum decrease in Hz over 28sec 2016
Maximum decrease in Hz over 28sec 2017
Dispatch Interval
Day
00:00
03:00
06:00
09:00
12:00
15:00
18:00
21:00
00:00
01-Jan
01-Apr
01-Jul
01-Oct
01-Jan
01-Feb
01-Mar
01-May
01-Jun
01-Aug
-0.02
-0.04
-0.06
-0.08
-0.1
-0.12
-0.14
-0.16
-0.18

Investigation into the AGC regulation system

1. High level description of the AGC system

The redefinition of the generation event from a unit 'trip' to system changing load over a period of time appears premised on the new demands placed on the system from utility solar PV and wind farms. In particular AEMO has suggested the AGC system used to regulate frequency within the NOFB cannot respond within 30 seconds. This sets the time limit for the definition.

AEMO states:

"*In fact, under current market frameworks, contingency FCAS is the only market service that is able to deal with very rapid and significant changes. Regulation FCAS is only able to respond to system frequency over a significantly longer time frame, approximately 30 seconds*[12]"

It would be helpful for AEMO to substantiate this comment and provide detailed information on the AGC system, it settings, design features and performance. We recommend the Panel investigate the performance of the AGC system further rather than simply rely on AEMO's statement to form the basis of the FOS.

Please note that AEMO itself has stated:

"*given the inherent delays in the AGC system, the fastest feasible response time from regulation FCAS providers is of the order of five to ten seconds*[13]".

This appears premised on the time of the 'AGC cycle' which requires time for measurement and calculation of unit set points.

AGC is a proprietary control system of AEMO with specific settings designed for a purpose. It is worth investigating whether the settings can be changed and system improved to serve the changing demands of the power system. How long AEMO takes to measure, calculate send signals is something it should be aware of and seek to improve.

AEMO operates two independent AGC systems for Tasmania and the Mainland. The system inputs are ***measured frequency*** and ***time error***. Given Basslink transfers frequency these should be similar, or follow.

The system works by converting:

- frequency error into a MW deficiency in the system, an "Area Control Error filtered" ('ACEfilt') on a ***proportional*** basis, on the basis of 2,800 MW/Hz for the Mainland and 200MW/Hz for Tasmania (on the 1st April Tasmania had a variable number, approx 140MW/Hz); and
- time error is converted to a value the ***integral*** of ACE ('ACEint'), which is a MW deficiency equivalent to the time error.

These calculations present a MW deficiency that needs to be compensated for, however further processing to each variables is performed by each AGC system. The following figure presents the conversion of Hz deviation to MW for the two AGC systems.

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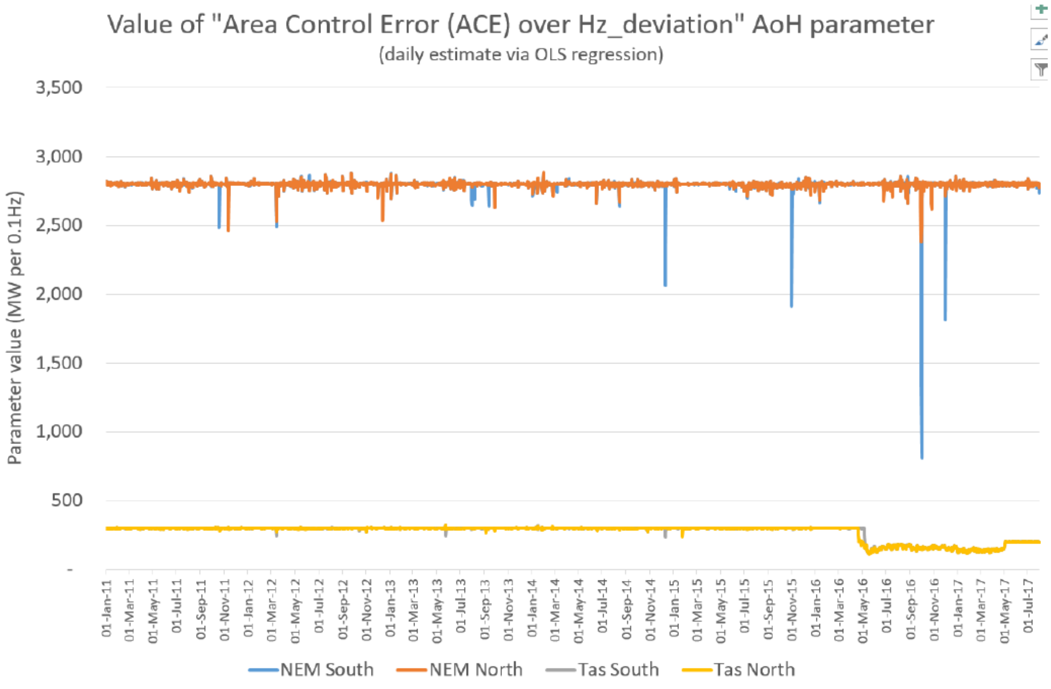
[12] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.8
[13] AEMO, Fast Frequency Response in the NEM – Working Paper – August 2017 pp.39



Source: PD view

Each system uses variable ***'gain'*** settings that ***'amplify'*** the ACEfilt and ACEint.

These gain settings vary, but for example the following figure shows , for the 1st April 2017 the gain settings for ACEfilt. These settings were back-calculated by our consultant PD View to average 0.5 for Tasmania and 0.19 for Mainland.

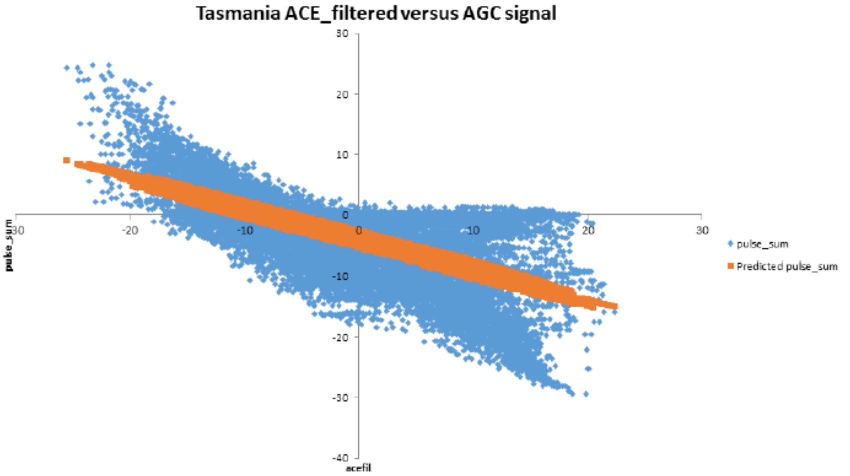


Chart 10

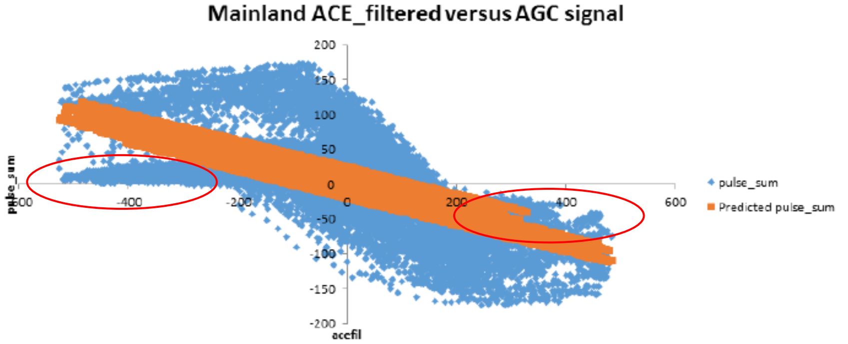


Chart 11

The slope of two graphs which represents the *ACE_Gain* is 0.19 and 0.5 for the Mainland and Tasmania respectively.

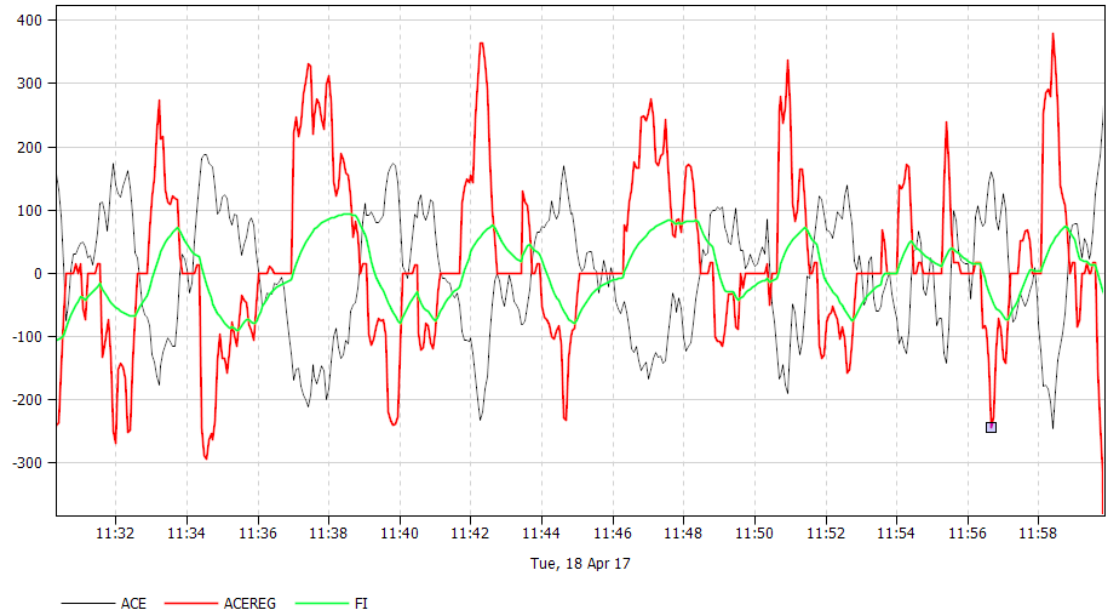
The gain settings vary to deliberately reduce control system response for small changes in frequency and increase response for larger changes. Please note that the calculations from PD View are the *actual* gain settings, after limitations on unit performance which we explain below, and are therefore likely to be far lower than the *intended* gain settings prior to distributing signals to the units.

The gain values should increase the signals (pulse) in the figure above with ACE. It appears the values in the red ovals are not by design – the signals are not amplified as much as they should be.

The sum of (ACEfilt*gain) and (ACEint*int_gain) is then distributed in each system to enabled units in proportion to the enabled amount as a signal in relation to a **Regulation Participation Factor** ('RPF'). The signal is then ***filtered with a time constant*** of approximately 32 seconds[14].

AEMO illustrated these elements in its April 2017 presentation, slide 14, in a workshop discussing the Causer Pays Procedure.

[14] DIGSilent presentation prepared for AEMO - 9th August, presentation to AS-TAG



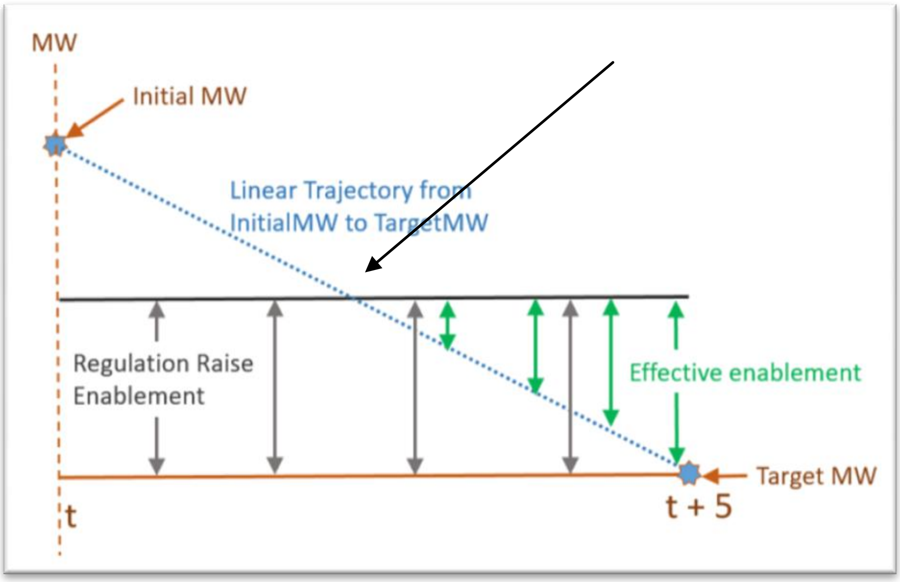
The Raw ACE is in grey. ACE_Reg in red has the sign changed and gains are applied, including a dead band. The filtered output FI is shown in green. The figure does not illustrate ACE_Int, but this is a second order adjustment.

The RPF is limited by a regulation margin, which means the unit will only receive a signal if the 4 second load data is within its ***basepoint plus or minus the enablement*** *(depending on raise or lower)*: this is the target at the end of the five minutes plus the MW enabled for Regulation. This has the effect of limiting the signals a unit will receive, early in a dispatch interval, when the unit is moving to a new basepoint, or when the unit has already been responding to a signal in the previous dispatch interval.

The example below shows a unit whose MW value at the start of the dispatch interval is above the Total Cleared Target plus Regulation enablement.

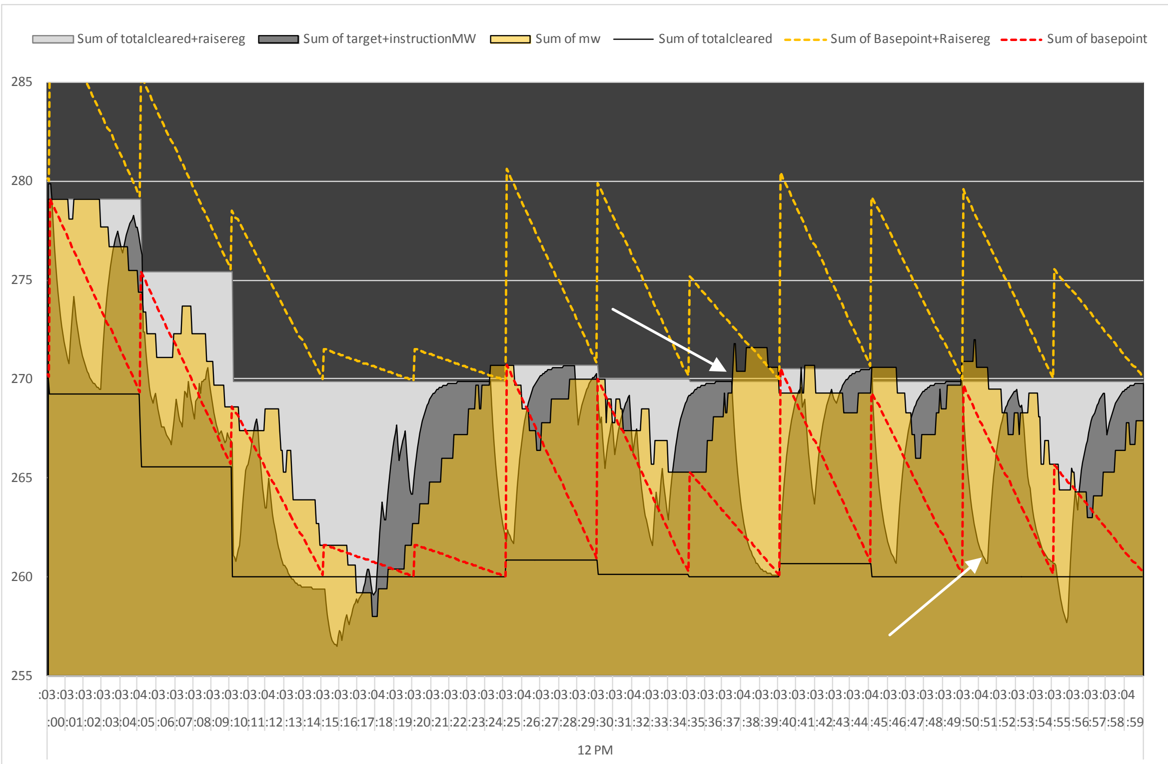
This may be simply because it had previously been utilised for Regulation and had previously been enabled for more Regulation than this dispatch interval, had responded to a contingency in the previous interval, or has simply wandered higher.

In this simple example the unit would not receive an AGC signal until the MW value reduces to within the Regulation enablement, which if it is following its trajectory, won't occur until half way through the dispatch interval. Please note this because it will become important later in this document.

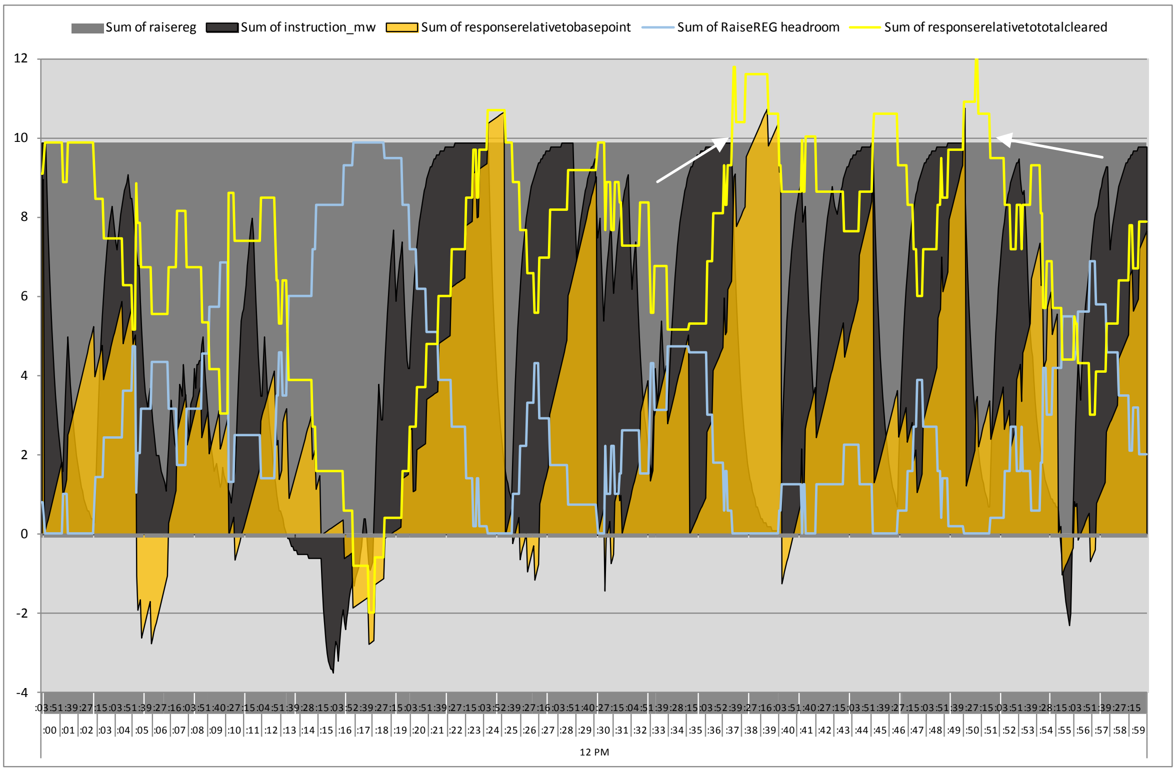


It is important to note **signals may precede the unit response, ignoring ramp rates**. This is shown in the figure below where the dark grey area is the cleared target plus AGC instruction and the transparent yellow is the 4 second MW value. The light grey area is the regulation enablement.

You can see, as shown by the white arrows, that the signal precedes the response, in a curve, and then drops away rapidly once the response has exceeded the target plus regulation enablement. The second white arrow shows that a signal will not be sent until the unit MW is below the cleared target plus the regulation enablement

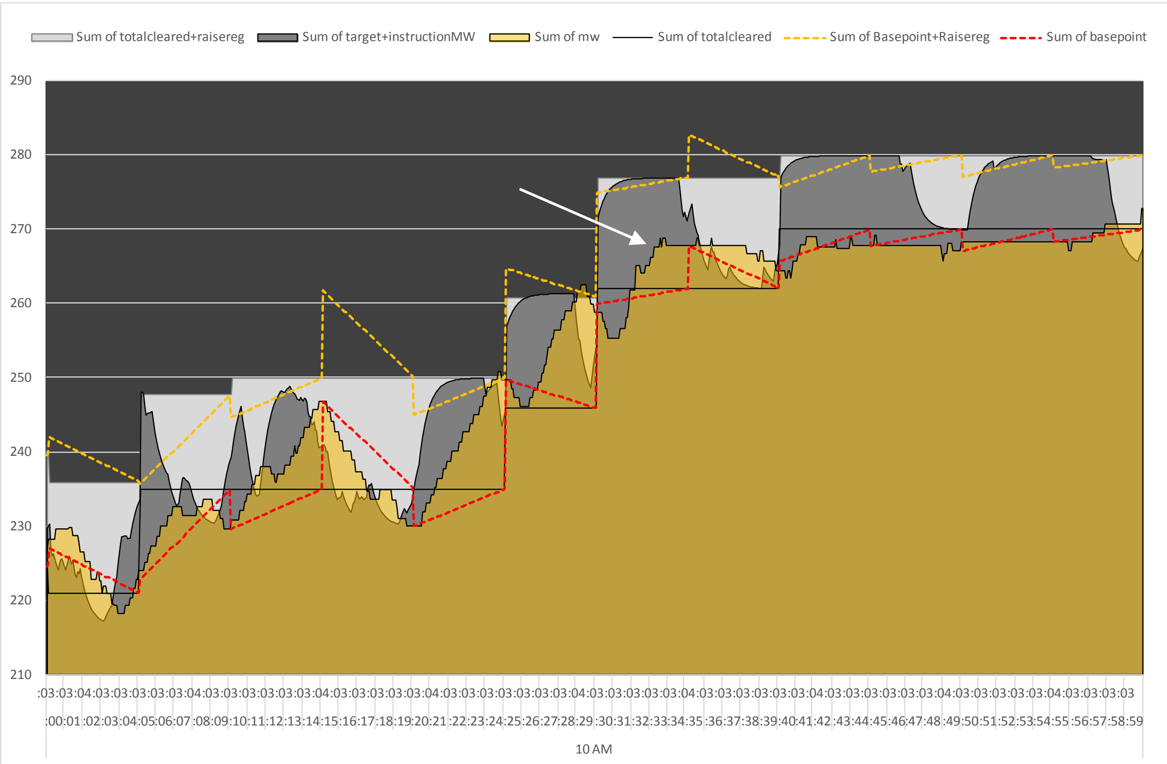


Whilst the above figure presents the data from the unit set-point or target, the following figure presents the data normalised around the cleared target, which is zero on the vertical axis.



The AGC system performs ***no real time validation*** of a unit's performance in responding to signals, such that a unit may be on AGC but not respond to signals. The unit will remain enabled for regulation FCAS in the next dispatch interval. This can affect performance of the AGC systems on occasion, although this could be fixed, it is unlikely to be systemic[15], nor is it likely to the primary cause for the deterioration in frequency.

The first figure presents GSTONE6, which appears to have a control limitation, unrelated to AGC SCADA set points. The unit had a transient availability problem that limited output and response to the AGC signals.



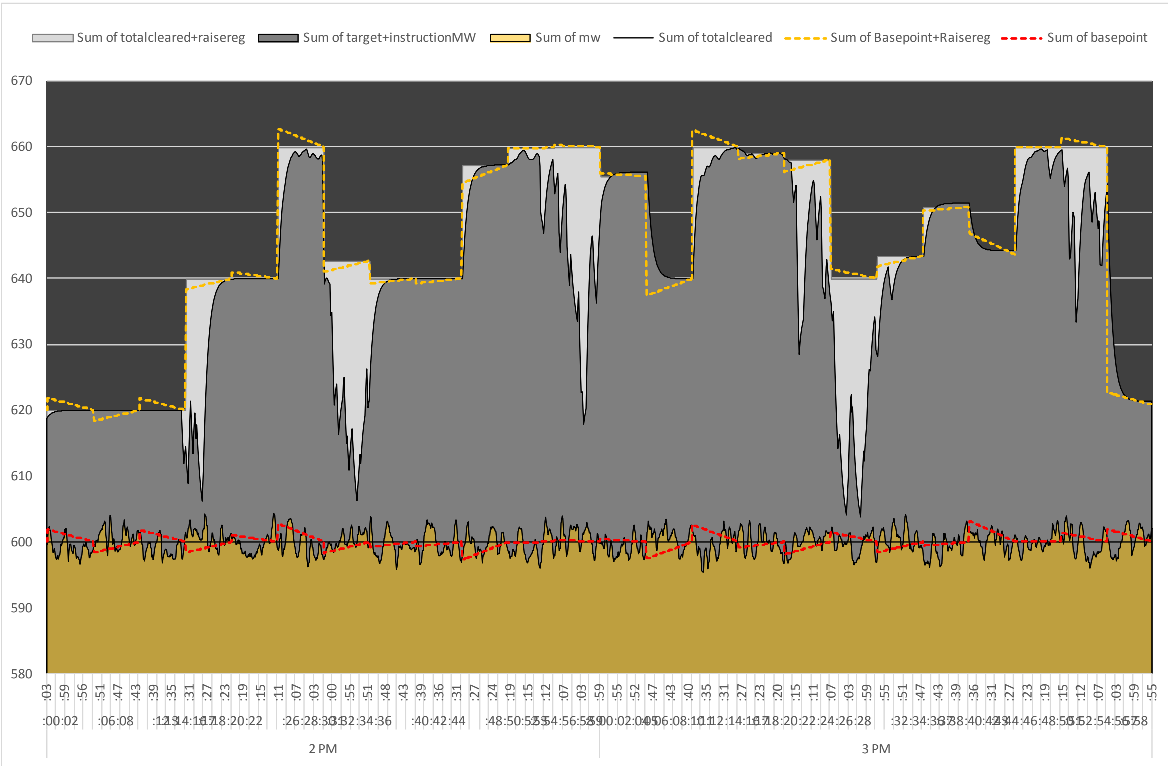
It is clear that the AGC system and NEMDE **needs to be updated to ensure that units which are not responding to AGC signals are not subsequently enabled for Regulation FCAS**. AEMO has no such process in place, thus leading to occasions where it continues to enable units irrespective of the performance in responding to AGC signals.

This problem is more likely to occur for units operating at higher loading where performance can be limited by numerous unit control limitations, which may be transient.

We recommend the **unit would be flagged by AEMO and not enabled in subsequent dispatch periods**. The unit controller can investigate the problem and improve the quality of the unit's performance.

The second figure presents MP2, this time over 2 hours on the 17th. The unit was enabled for up to 60MW of Regulation FCAS and did not respond. The unit had suffered availability problems, had reduced load (as can be shown by the target of 600MW, rather than up to the 700MW unit capacity). MP1 had similar problems in the hour preceding.

[15] PD View - An analysis of AGC relative effectiveness of Tasmania versus Mainland, and station performance



Please note that AEMO's NEMDE system does allow for the dispatch of FCAS, including Regulation FCAS, in excess of the unit's availability offered for dispatch.

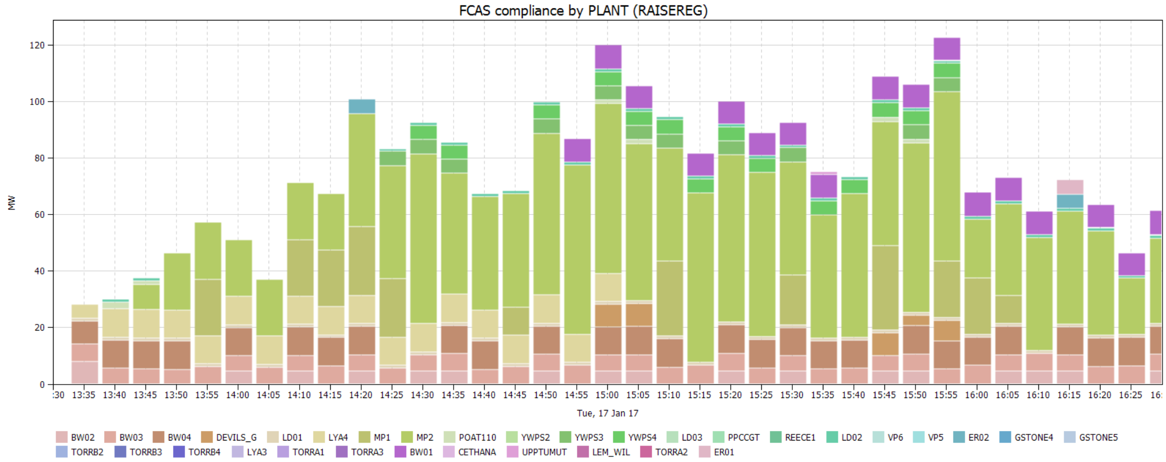
CS Energy ensures this does not occur by rebidding FCAS offers (regulation and contingency), specifically reducing the Regulation Max and Min to reflect unit availability and SCADA set points – this is to comply with Rule 3.8.7A(l) and 4.9.8(d). Other suppliers do not tend to do this.

In early 2016 CS Energy raised this with AEMO and **recommended amending NEMDE to avoid purchasing FCAS in excess of a unit's energy availability**. CS Energy called this '***grey market***' FCAS. CS Energy pressed this issue with AEMO for over a year, with little response from AEMO.

AEMO's formal response to CS Energy, in April 2017, was that it would be inappropriate for it to amend dispatch of FCAS to account for this issue, as in its opinion there can be situations where a generator is capable of providing FCAS beyond their energy max capability.

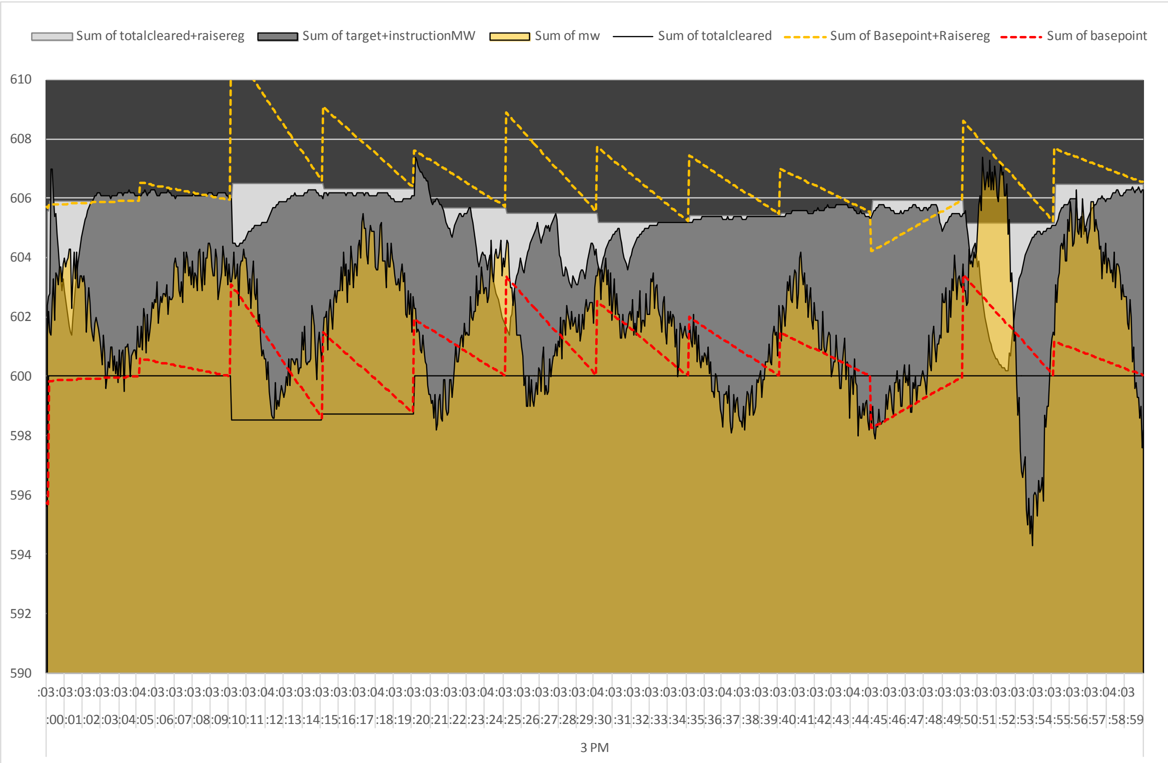
CS Energy was not persuaded by AEMO's response and the matter remains contended. Importantly, if either AEMO had followed CS Energy's recommendation, or other Participants rebid their FCAS offers in the same manner as CS Energy, incidents such as MP1 and MP2 on the 17th January would not have occurred.

The following figure presents the Regulation FCAS that was enabled in excess of a unit's bid availability, 'grey market FCAS' during the afternoon of the 17th January.

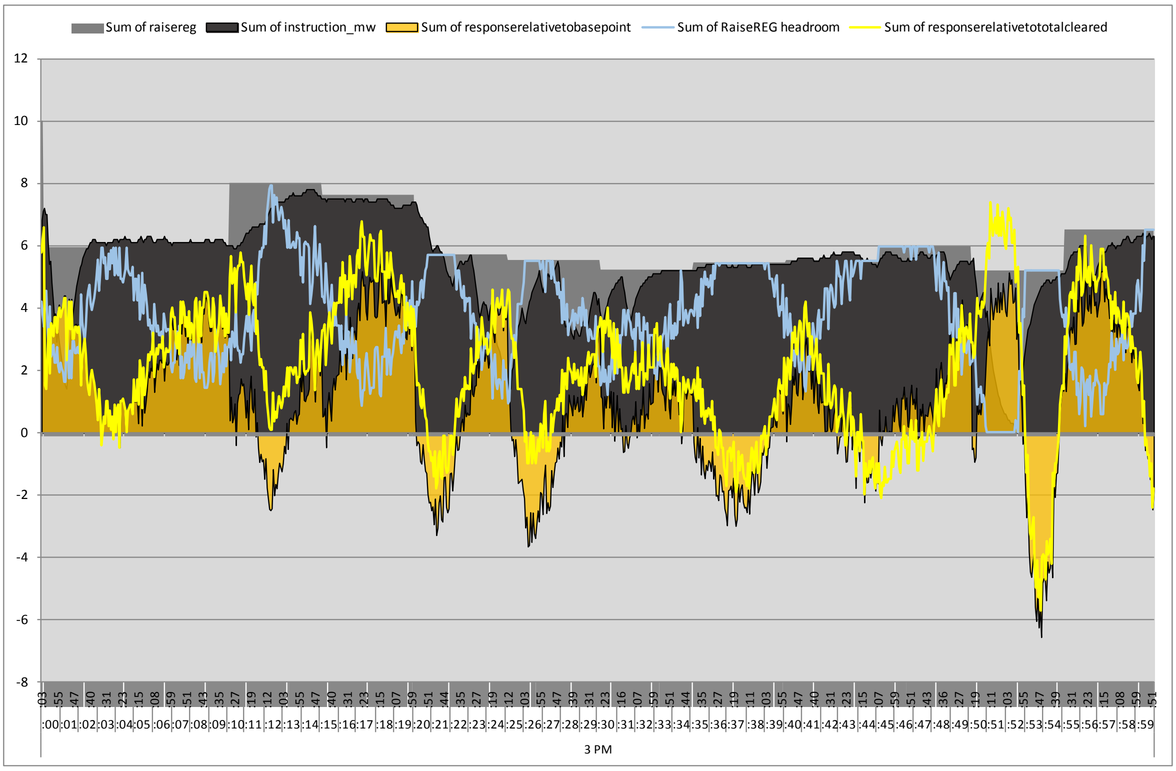


The quantities of grey market FCAS are material in relation to the total amount enabled. Considering the above is Regulation FCAS which, unlike Contingency FCAS, NEMDE will only dispatch if the SCADA upper set point tele-metered to AEMO allows it, it shows quality could be improved, especially at times of system stress and plant de-ratings. Numerous small errors between FCAS offers (specifically EnablementMax), unit bid availability, non-AGC unit limitations and SCADA tele-metered values can all diminish the quality of the service.

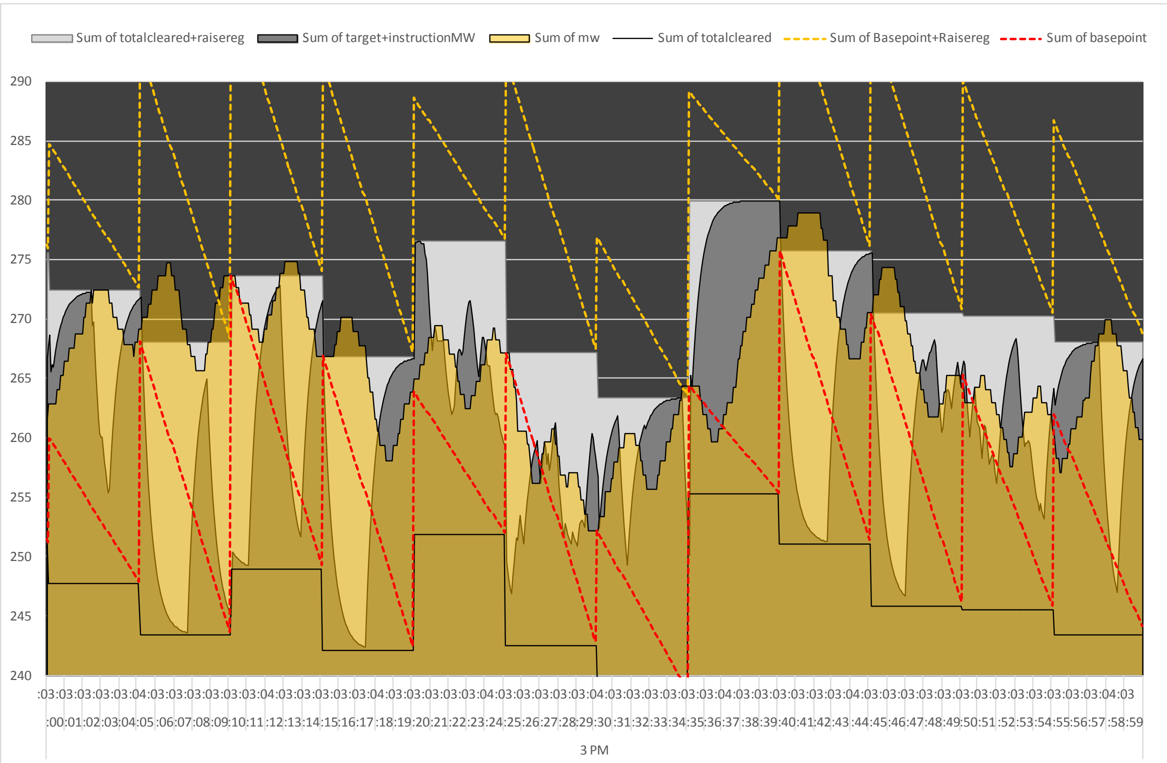
The following figures present unit BW03 on the 17th. The unit's availability was lower than the RaiseRegEnablementMAx, thus allowing it to be dispatched for Regulation services in excess of the dispatch it could achieve in the energy market. This is grey market FCAS: it wasn't sold in the energy market and has been resold in another parallel, FCAS market.



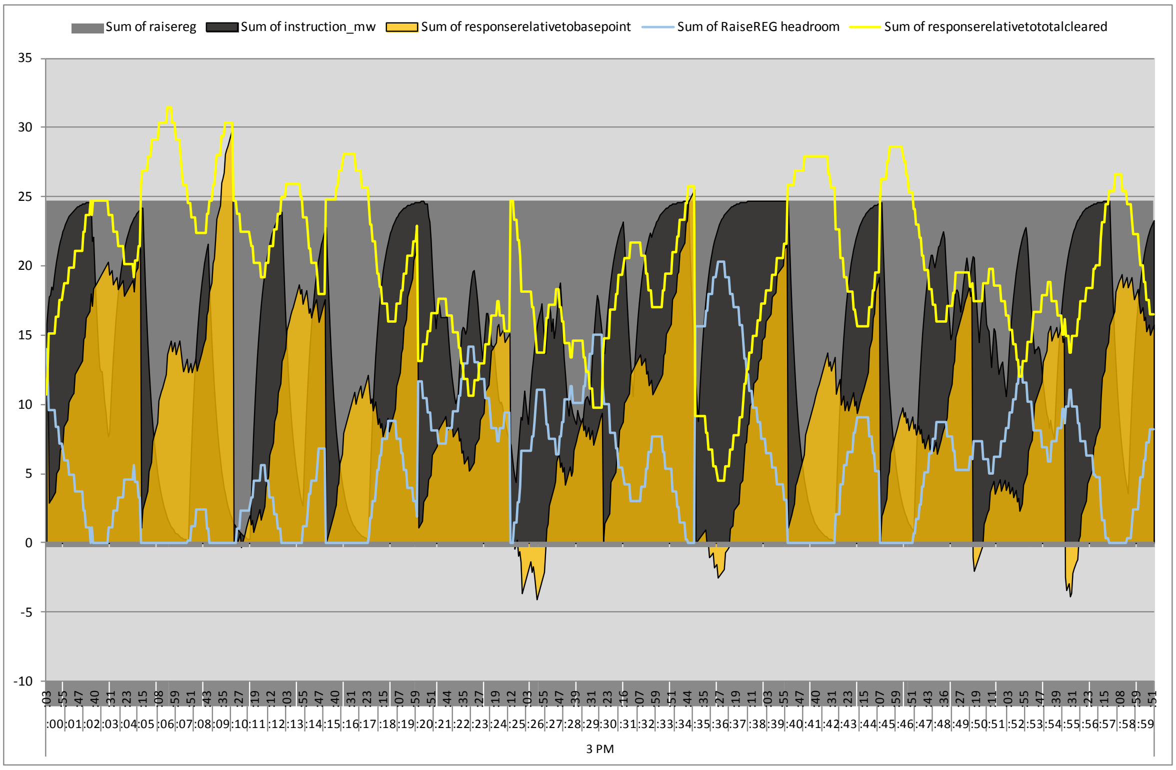
Whilst the unit did change load through the period, it didn't respond to AGC signals particularly well. Whether or not this was because of the availability problem or because of other unit controls we could not say: firstly because CS Energy does not own the unit and secondly because AEMO has no real time quality control of this parallel market. We shall investigate Bayswater further later in this submission.



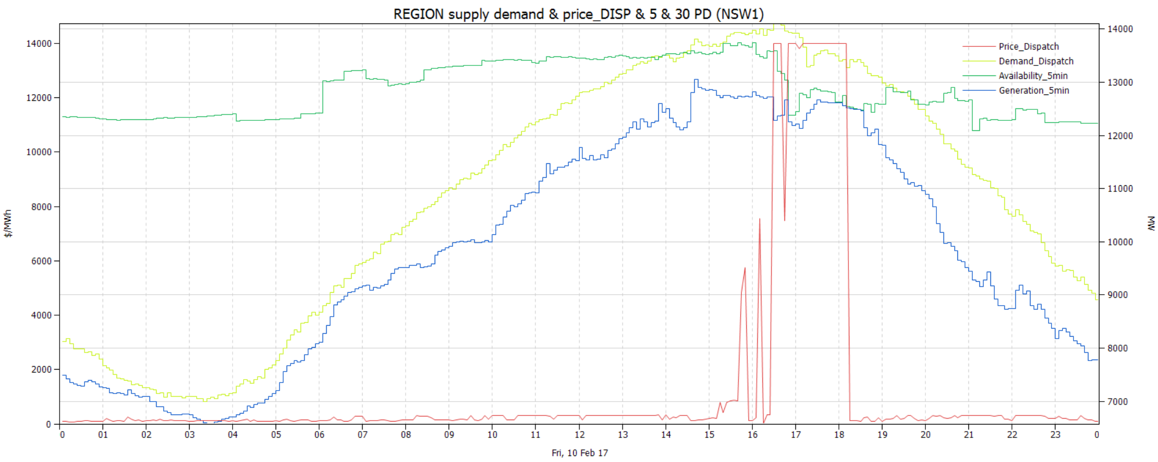
By comparison GSTONE4 shows a far more controlled response over the five minutes, even though its cleared targets are changing through the period.



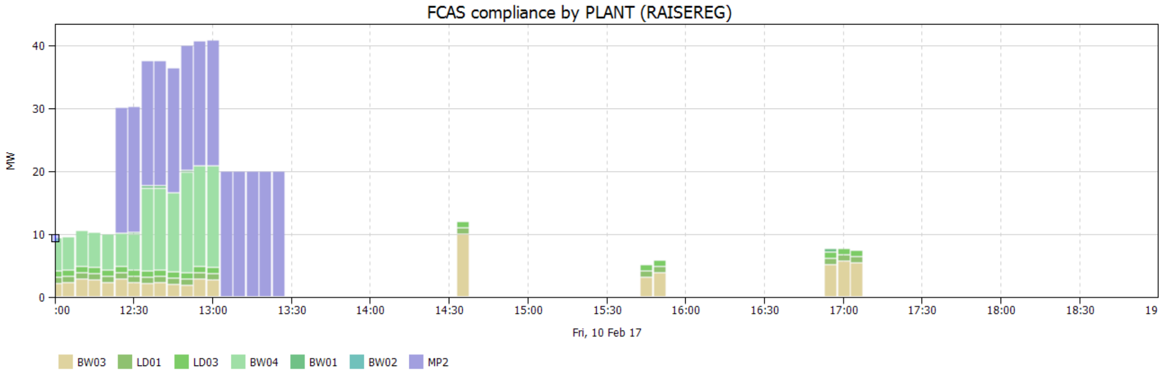
The same data is presents on a normalised basis with zero being the cleared target:



The problem there being too few quality controls in the FCAS markets is that situations such as those of the 17th January can occur on 'tighter' supply and demand days. On the 10th February AEMO instructed load shedding in NSW due to a lack of reserves – the price was set to the cap during this period.



During this afternoon, the same problem of the 17th occurred at MP2; luckily this unit was not enabled for FCAS later in the afternoon during periods of LOR2 & LOR3. It should be noted that BW03 and Liddell units were enabled for Regulation FCAS during the period.



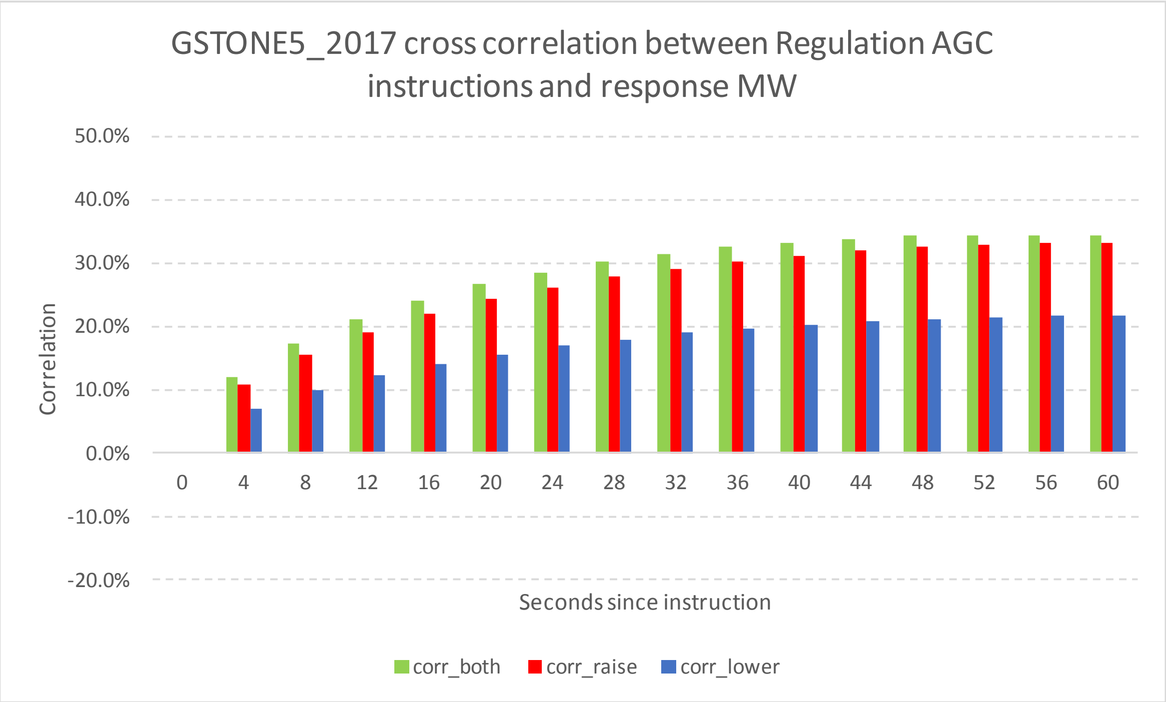
This is a completely counter-intuitive outcome given the NEM's security constrained dispatch – units in NSW should have been dispatched in the energy market and units from other states should be regulating frequency. This only occurred because there was no quality control between the energy and FCAS market to stop it.

2. Can the AGC system's response be accelerated?

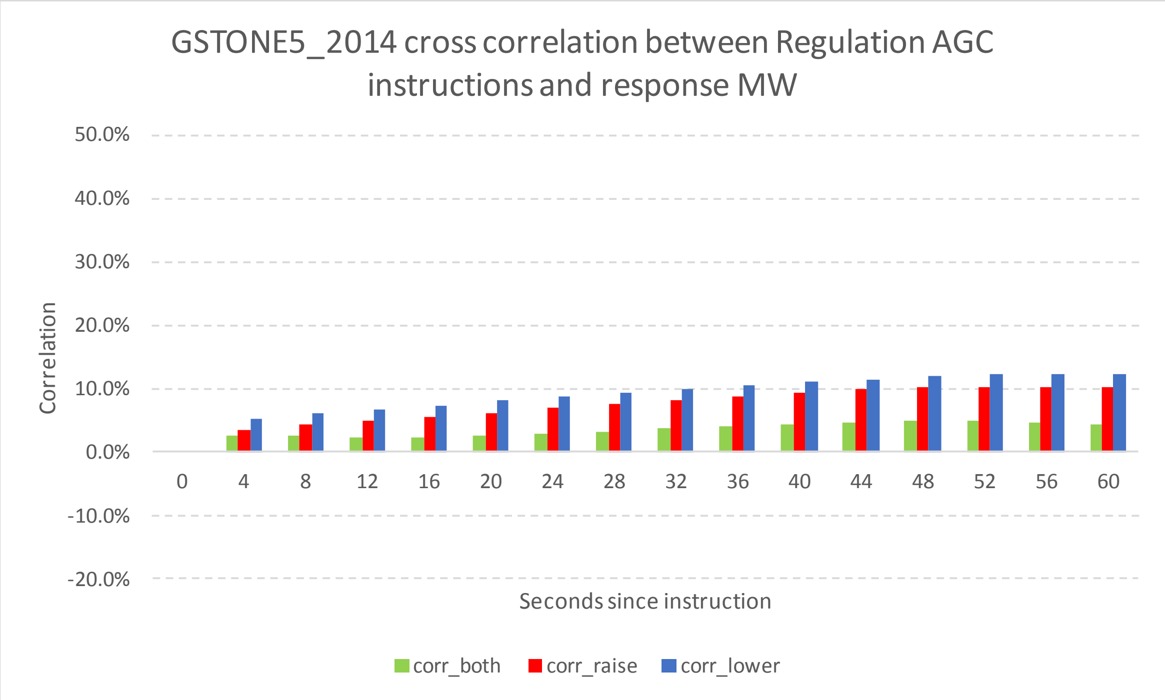
The speed of the AGC system is a function of both its design and the expected unit response. It may vary, depending on the unit, as to which is the limiting factor. Further assessment on the performance of units and the speed of signals is warranted. As has been seen, ramp rates for units providing regulation FCAS assist in providing regulation faster in the five minute interval.

PD view has assessed the correlation of each unit's response to its AGC signals over 2011 to 2017. Given signals precede the unit response and ignoring ramp rates there is never going to be a very strong correlation in the first few seconds: the AGC pulses are a 'nudge' in the right direction. Equally the 'drop off' in the AGC signal when the unit exceeds the Enablement plus Cleared Target (regulation headroom), when the regulation margin is zero, would also reduce the correlation. Nevertheless there should be a reasonable correlation between the unit response and the signal, albeit delayed. The delay in the correlation should indicate how fast the unit is responding, notwithstanding this is a function of its ramp rate, which is the unit operator can control and will be reflected in how much regulation can be enabled over the 5 minutes. E.g. at 3MW/min ramp rate only 15MW can be enabled for a 5 minute dispatch interval.

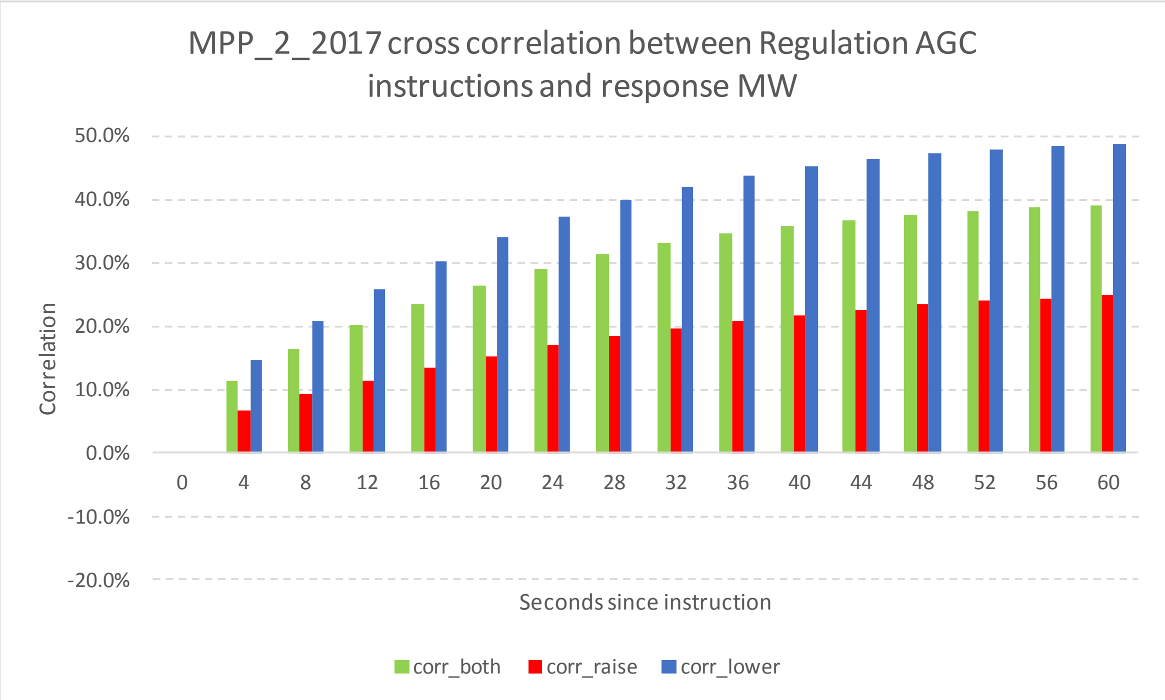
This is shown in the chart below for GSTONE5. This unit operates with a fixed dead-band of +/-0.1Hz and provides regulation FCAS almost continuously when it has the capacity to do so. It shows there is a correlation between the signal and the response well within the 30 seconds, which shows that units can respond to signals effectively within a short period.



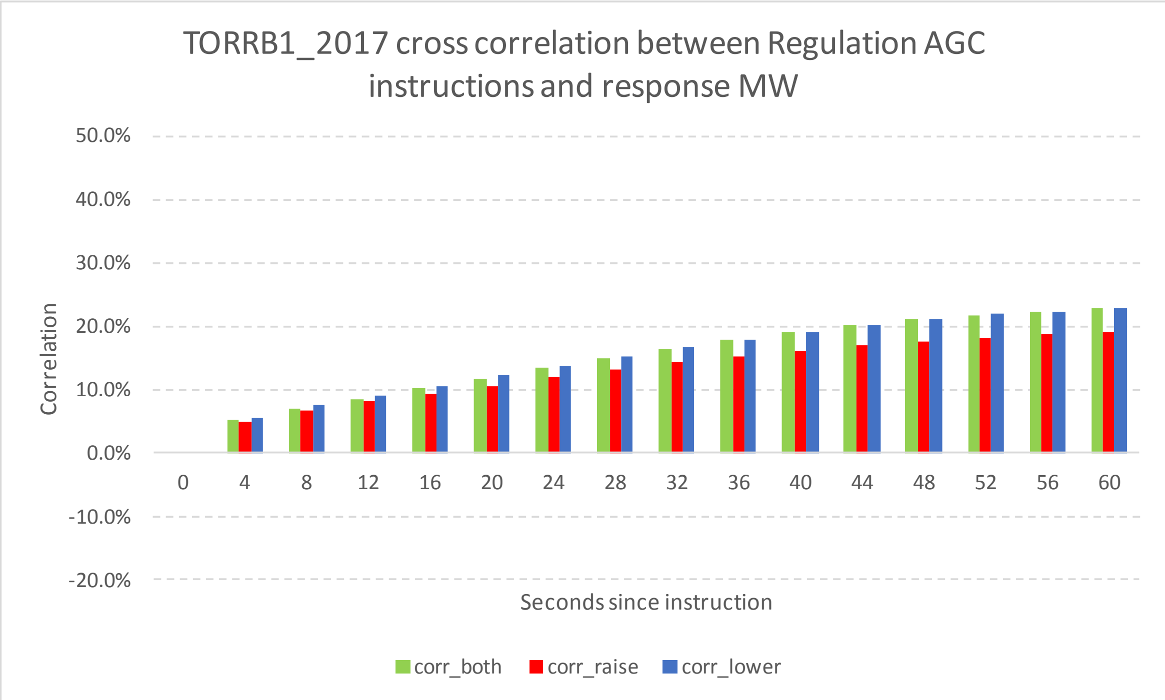
What is of interest is the performance prior to and during 2014. GSTONE5 operated with very wide dead-bands at the time, such that the unit operator would only put them in when the unit was at minimum load and not able to provide FCAS, overnight. At all other times GSTONE5 would have responded to frequency with governor response (PFC).



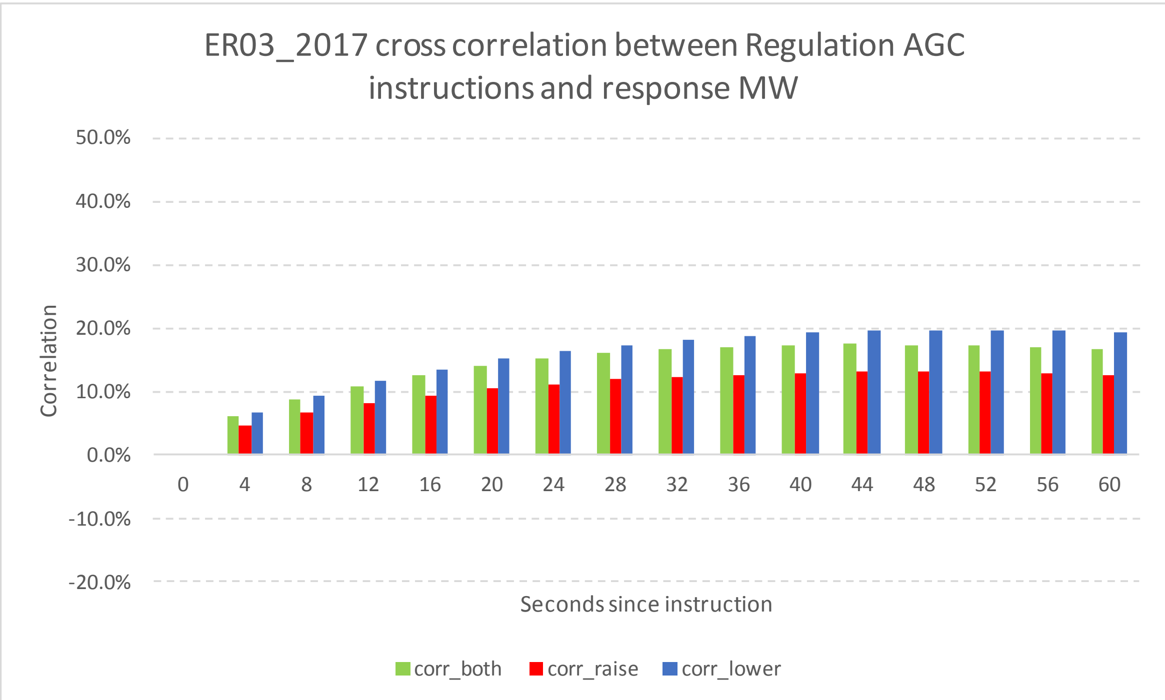
Millmerran is a unit recently registered for Regulation FCAS and has provided little, volume under a series of what appear to be a series of test rebids in 2017. Millmerran is typically not competitive for regulation services as it is a low merit order plant that should be fully dispatched in the energy market. We would therefore expect Millmerran to show good performance. The correlation is strong, especially for lower regulation signals.

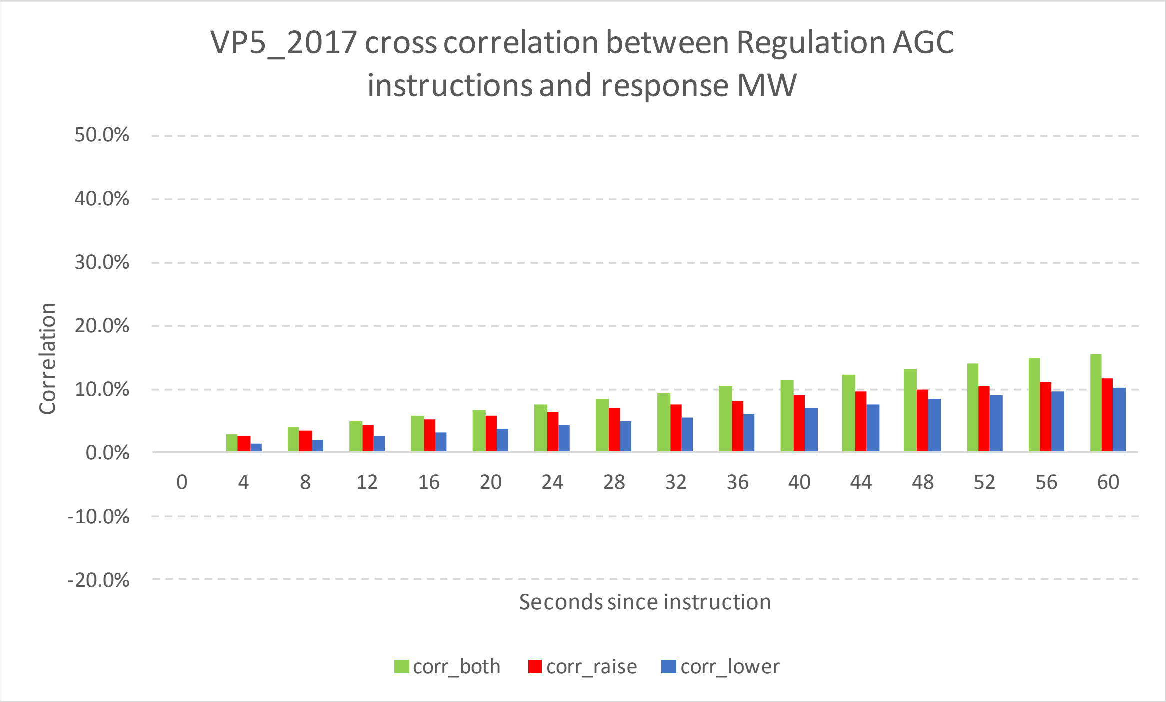


The Torrens correlations are somewhat slower, but consistent.



Eraring and Vales Point remain with a positive correlation, yet this is less than GSTONE, MPP and TORRB. This may be due to being enabled at times of lower ramp rates, the units typically operating at higher loading when the unit base-point is changing. Whilst we speculate, some NSW units may be fitted with unit controllers that aim to counter-act the governor response from hydraulic governors.

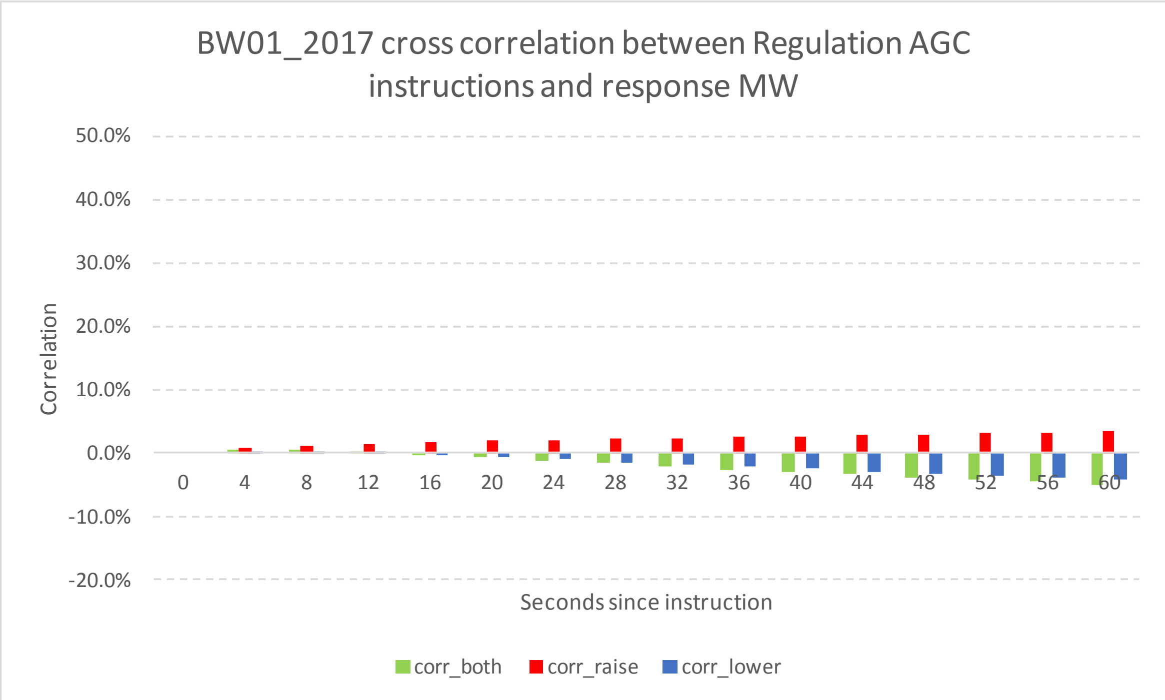


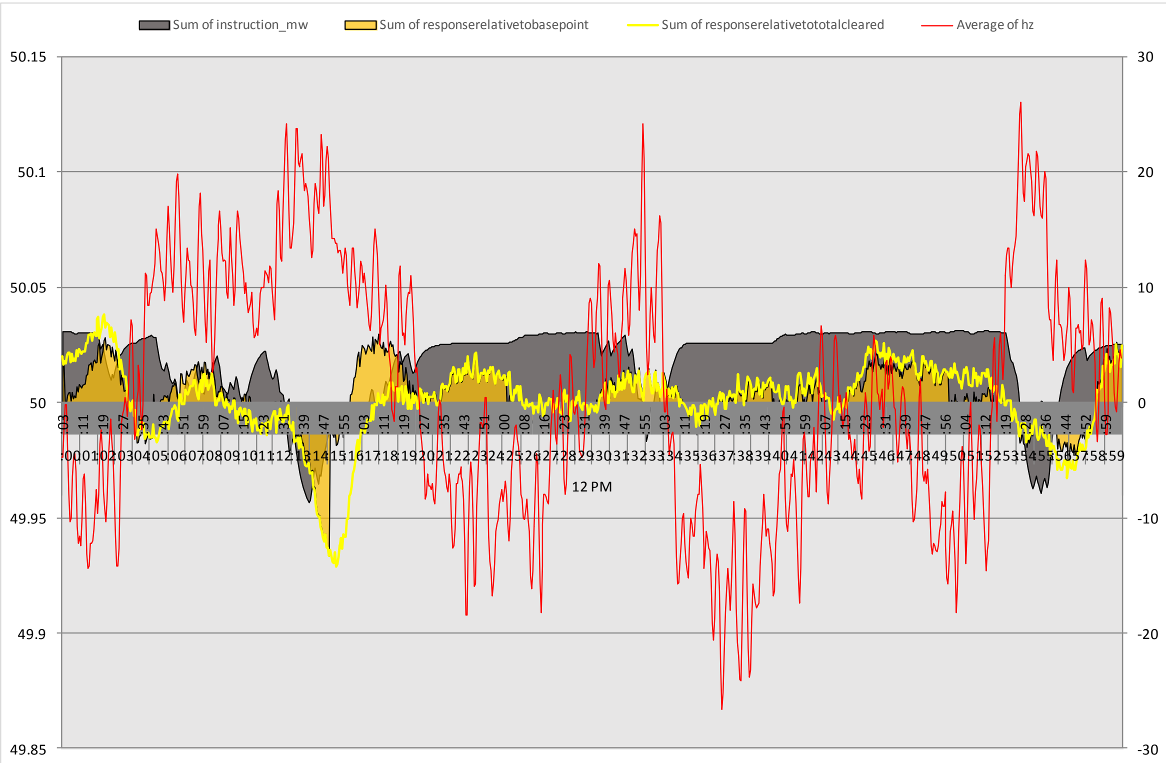


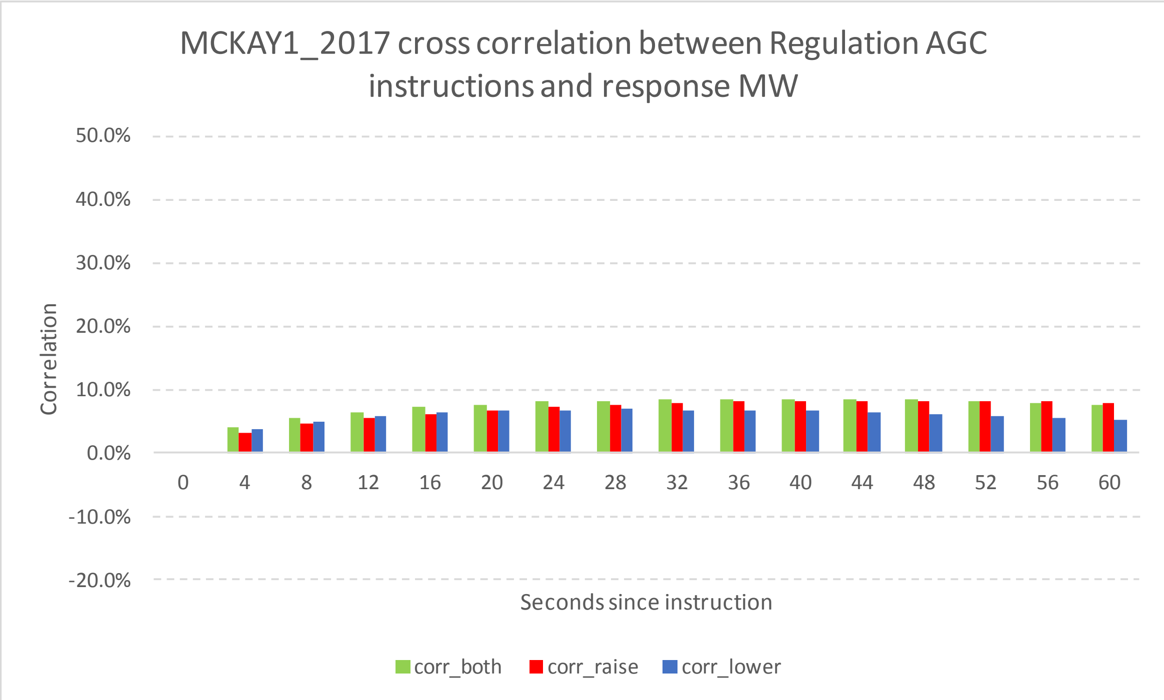
The correlation of the Bayswater, Gordon, McKay, Murray and John Butters are all low. Given these correlations are similar to Gladstone prior to implementing a +/-0.1Hz dead-band, this suggests the units may be independently following frequency rather than the AGC signals.

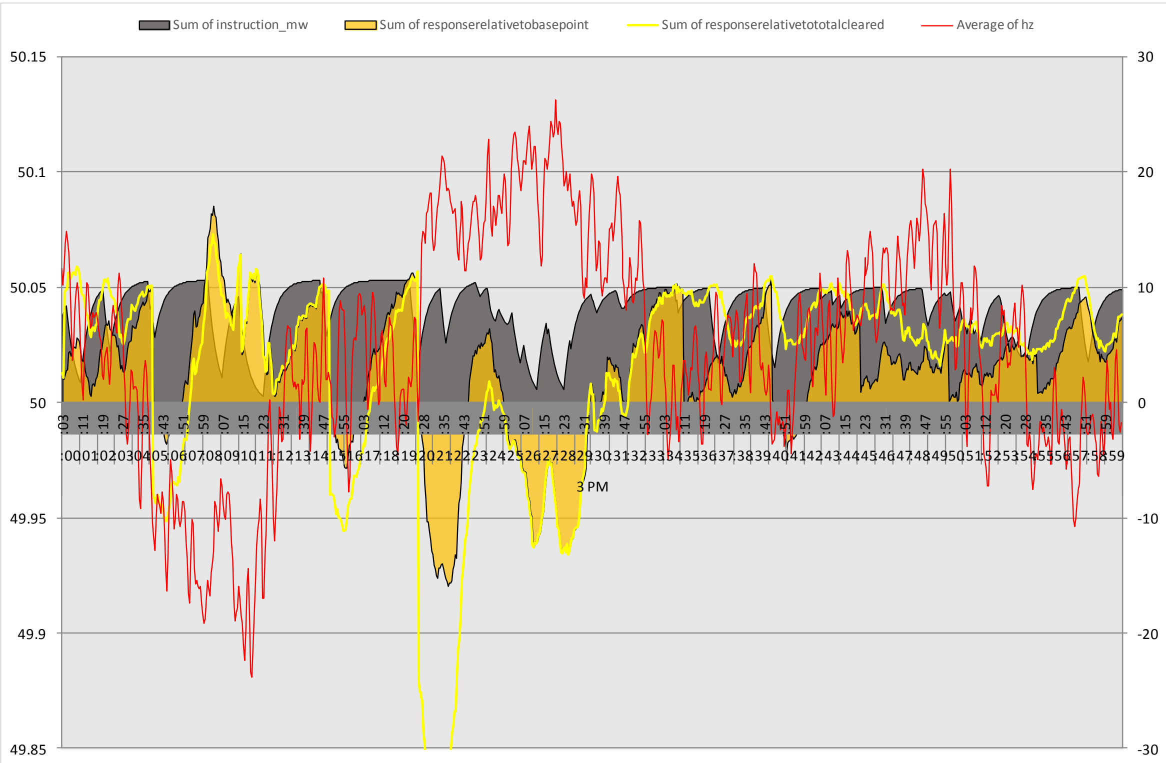
To CS Energy it is therefore unclear as to whether the reduction in PFC is as a result of the **widening of dead-bands** or a r**eduction in reserve 'headroom' of synchronous units providing governor control**. It is probably both.

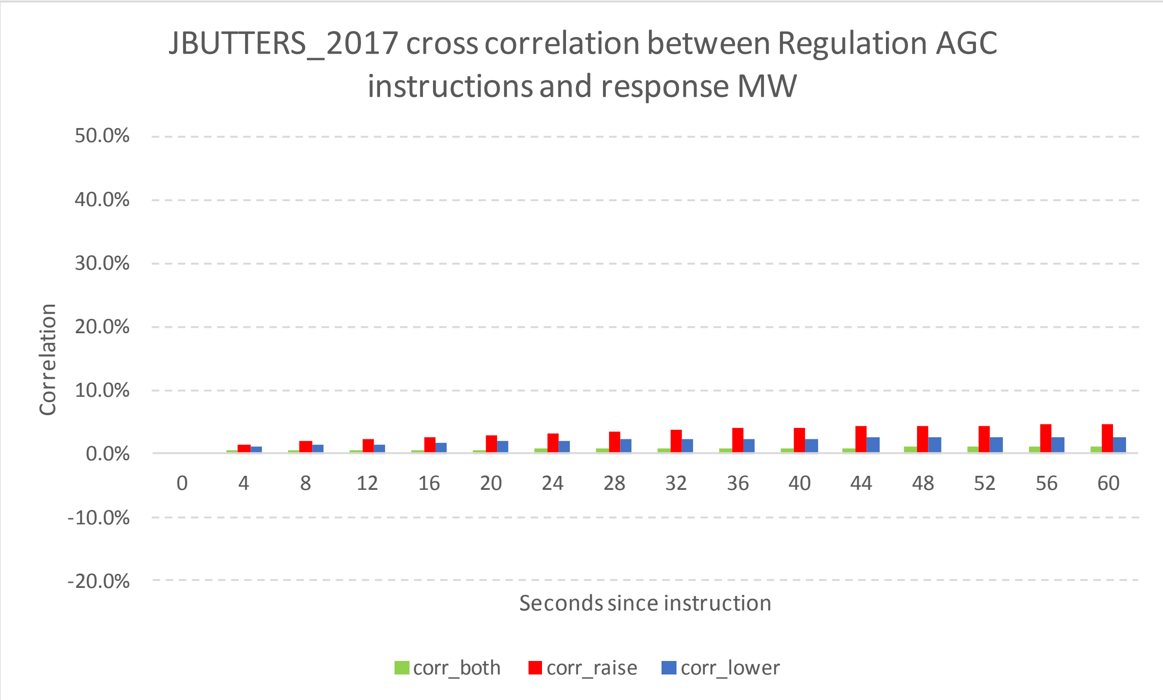
It should be noted that Bayswater often operates with its Raise Regulation Max Enablement set above the unit's energy availability. In such an instance NEMDE cannot dispatch the unit above the energy availability in the energy market, but can send the unit AGC signals to increase load. It is our opinion that performance can degrade at higher loads due to the likelihood of another unit limitation reducing MW output. This is why we recommend implementing some central quality controls in the AGC and NEMDE systems.

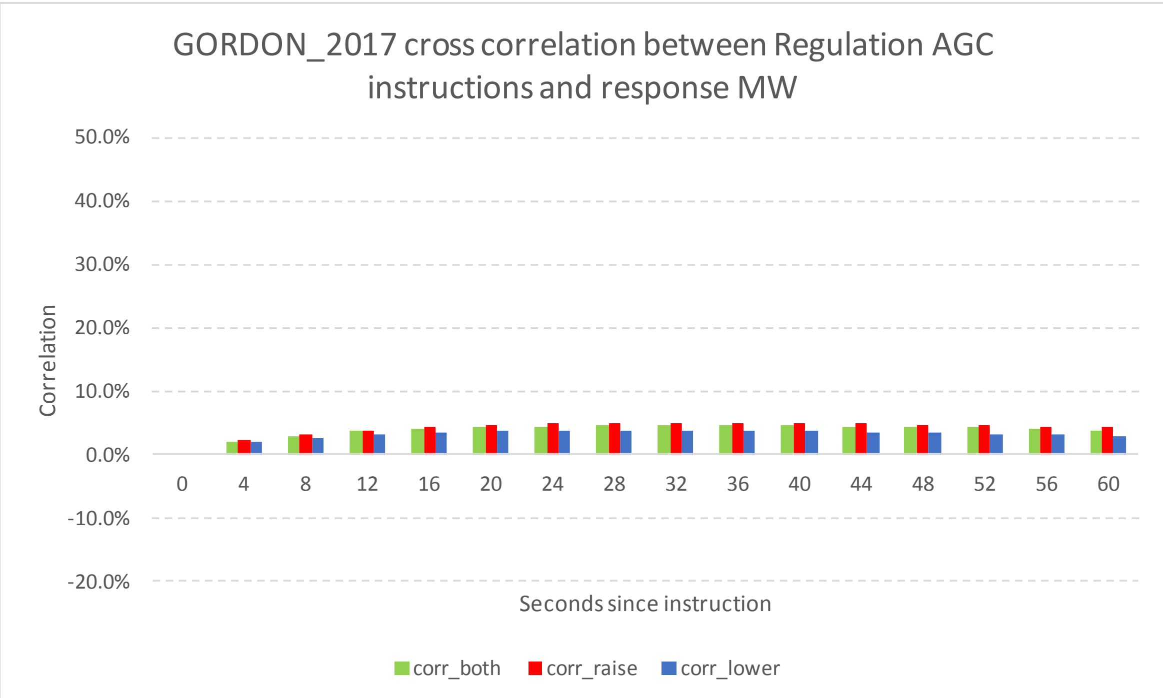

BW01_2017 cross correlation between Regulation AGC instructions and response MW
Correlation
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
-10.0%
-20.0%
0
4
8
12
16
20
24
28
32
36
40
44
48
52
56
60
Seconds since instruction
corr_both
corr_raise
corr_lower


Sum of instruction_mw
Sum of responserelativetobasepoint
Sum of responserelativetototalcleared
Average of hz
50.15
50.1
50.05
50
49.95
49.9
49.85
30
20
10
0
-10
-20
-30
12 PM


MCKAY1_2017 cross correlation between Regulation AGC instructions and response MW
Correlation
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
-10.0%
-20.0%
0
4
8
12
16
20
24
28
32
36
40
44
48
52
56
60
Seconds since instruction
corr_both
corr_raise
corr_lower


Sum of instruction_mw
Sum of responserelativetobasepoint
Sum of responserelativetototalcleared
Average of hz
50.15
50.1
50.05
50
49.95
49.9
49.85
30
20
10
0
-10
-20
-30
3 PM


JBUTTERS_2017 cross correlation between Regulation AGC instructions and response MW
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
-10.0%
-20.0%
Correlation
0
4
8
12
16
20
24
28
32
36
40
44
48
52
56
60
Seconds since instruction
corr_both
corr_raise
corr_lower


GORDON_2017 cross correlation between Regulation AGC instructions and response MW
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
-10.0%
-20.0%
Correlation
0
4
8
12
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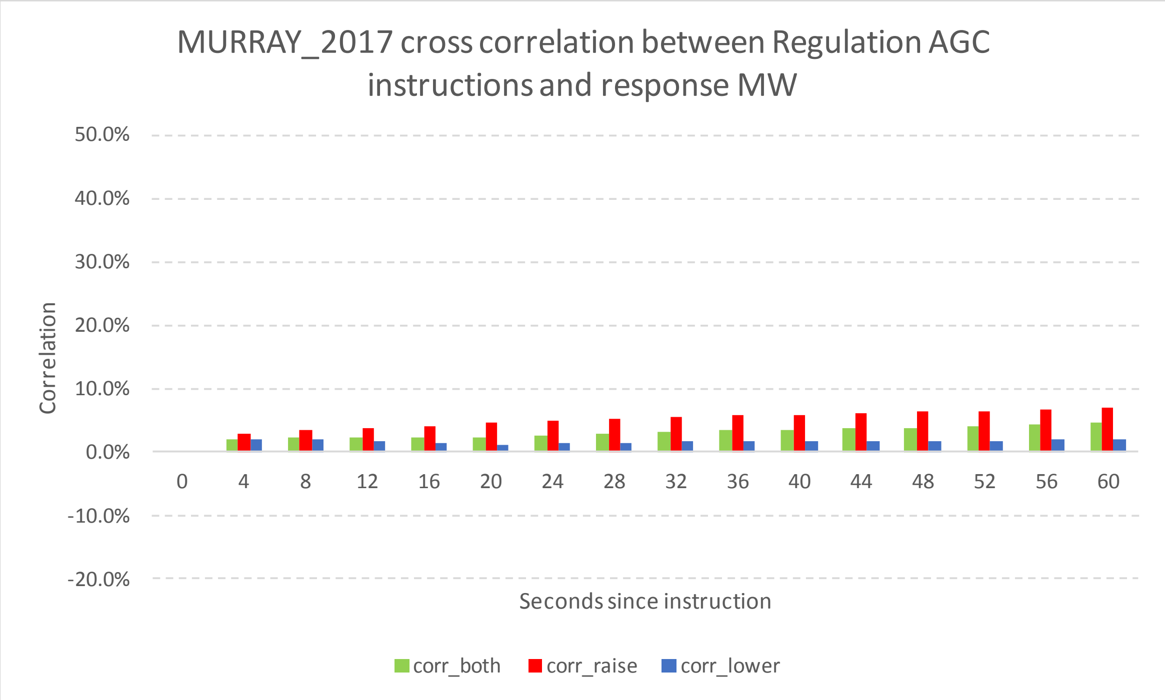
Seconds since instruction
corr_both
corr_raise
corr_lower



The charts above show that **some units respond in a manner intended by the AGC system when enabled for regulation, whereas other units that provide Regulation FCAS may not**. These units may well be responding instead to frequency through governor droop. Those that are **responding well are responding quite quickly**, within 30 seconds, in a controlled manner depending on the unit ramp rate.

It is a rather interesting observation that, whilst AEMO cites the withdrawal of primary frequency control as a reason for deteriorating frequency it also appears to be a reason why units may not be responding to AGC signals.

In any case there appears **no reason why such varied response is acceptable amongst regulation providers**, given the function it performs in correcting frequency deviations and accumulated time error.

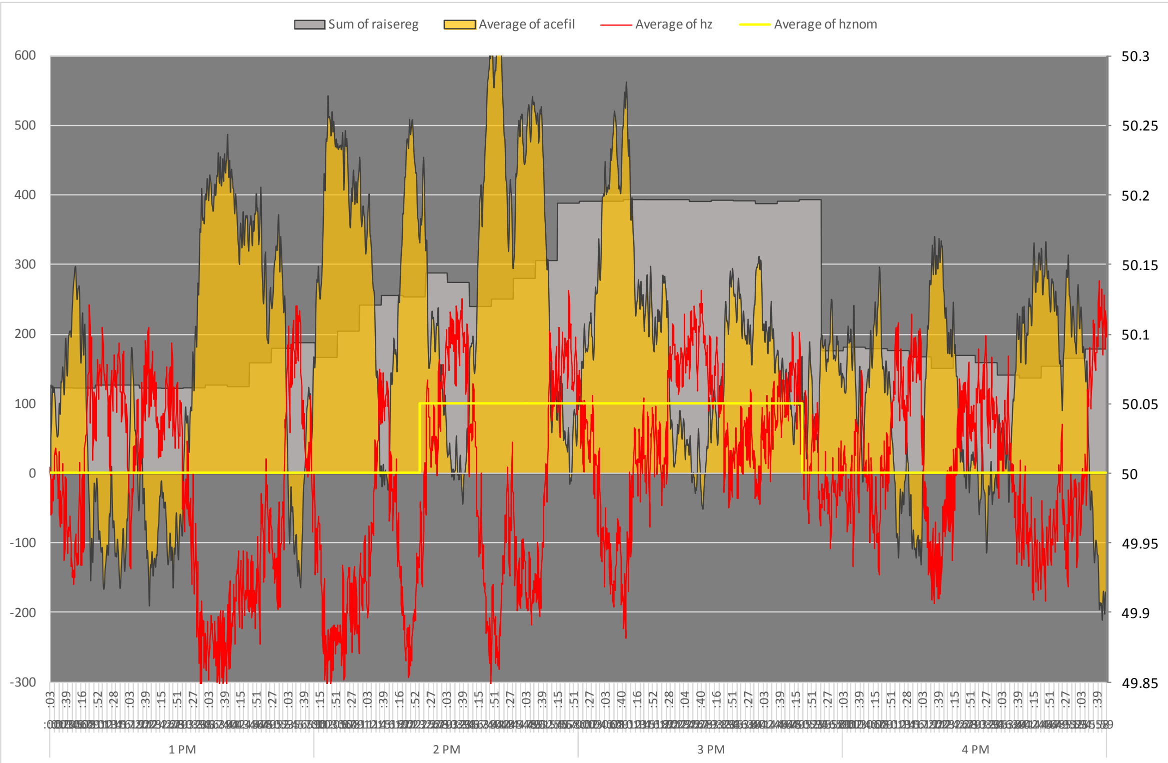
In conclusion, we consider it likely, depending on AEMO's data handling time, that units can respond in less than 30 seconds especially if they offer higher ramp rates. A systematic improvement in quality control of this product implemented by both the providers and centrally by AEMO would help. In any case, given events less than 30 seconds do not appear to be that common, the response appears adequate for managing deviations within throughout the five minutes – the question is why therefore it isn't.

3. Will the AGC system's response be accelerated if more is purchased?

The quantity of response provided by a unit increases through a dispatch interval. The purchase of more enablement would have the effect of increasing the availability of response earlier in the interval, especially when units are changing base-point (ramping or responding to an AGC Reg signal from the previous interval).

It would also allow for more to be provided later in the interval if there is a sustained deviation over the dispatch interval. It is worth investigating whether the current 130MW and 120MW requirements are adequate. This can be performed by assessing the 4 second ACE and ACEint values, should AEMO provide the variable gain settings that it has used in order to calculate the frequency indicator or FI, which dictates the signals for desired response from enabled units.

The chart below presents data from the 17th January 2017. The raise reg enabled (light grey) excluding those providers <3MW is compared to the problem 'ACEfil' which is the MW quantity required on the Mainland for the Hz deviation from 50Hz. This is multiplied by -1 to provide an indication of real time requirement to correct frequency. It is typically positive when frequency is below 50Hz. Hznom is the target frequency which is adjusted at certain times to correct time error.



The opinion of PD View is that AEMO should assess over the previous dispatch interval when FI has been greater than the sum of the instruction pulses sent to enabled units. This would show times when demand for regulation services has been greater than the available supply. Calculate this metric for both raise and lower services.

The converse can also be calculated, where FI is less the signals sent to enabled units. This would show periods when supply of regulation services is greater than the demand for regulation services. Make this metric for both raise and lower services.

The above metrics would indicate how much regulation services NEMDE is required to buy for the next Dispatch Interval. When metric (a) is high then NEMDE/AEMO should buy more regulation services in the next interval to help correct frequency. When metric (b) is high then NEMDE/AEMO should buy less regulation services in the next interval to save consumers money.

PD View consider it would be possible to attempt to forecast the above metrics using deterministic variables such as time of day, demand, change in demand, change in output from volatile units (e.g. semi-scheduled), inertia, forecast cloud cover, etc. These metrics can be fed into Predispatch so that predispatch has a sensible estimate of how much regulation services will be needed over the next 1.5 days and generators can plan to respond to periods of high demand for regulation services.

Additionally it would be sensible to assess whether the volume of enabled FCAS should be a function of frequency at the end of the last dispatch interval. The implicit assumption (of current dispatch logic) is that regulation FCAS volume will be utilised increasingly over the dispatch interval. This assumes that frequency is near 50Hz at the end of each dispatch interval and hence minimal volume will be signalled at the beginning of a dispatch interval. This does not appear to be true.

The purpose of the NEMDE and the AGC system is to calculate dispatch targets for the next five minutes, setting trajectories for scheduled generators and loads based on AEMO's forecast of demand, PV and wind generation. There will always be errors in these forecasts, plus there will also be deviations from the trajectories for scheduled units.

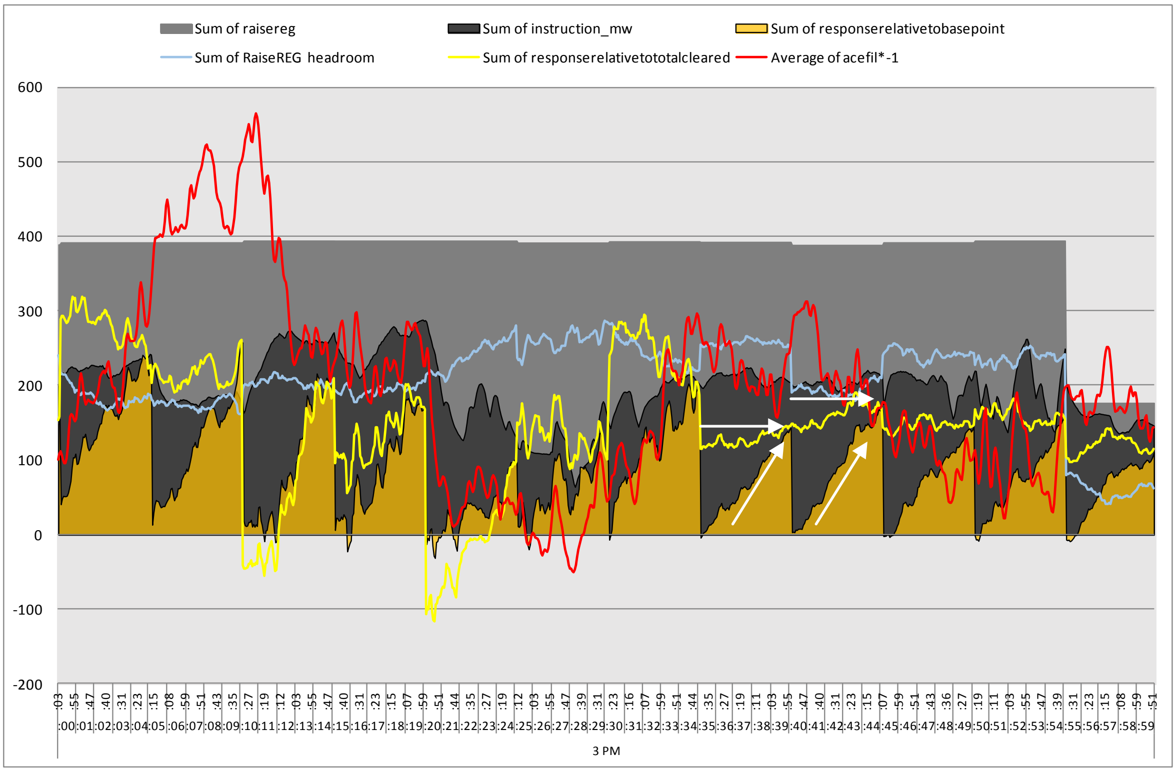
Regulation FCAS aims to change units' trajectories to compensate for these errors. A core assumption appears, absent a contingency (trip of unit, load or network element) which could happen at any time in the interval, the error and resultant effect increases throughout the five minutes. This adjustment to target is a particular facet of the regulation system when NEMDE 'co-optimises' energy and FCAS, which is when the dispatch algorithm determines it will reduce costs by buying FCAS rather than energy from a unit. NEMDE therefore changes the unit set point in the energy market to do so.

The following figure presents one hour of data on the 17th January 2017. This day was exceptional because AEMO procured 400MW of regulation FCAS after the mainland accumulated time error requirements continued to grow through the afternoon.

The figure presents ACEfil*-1 as the red line and is positive showing low frequency.

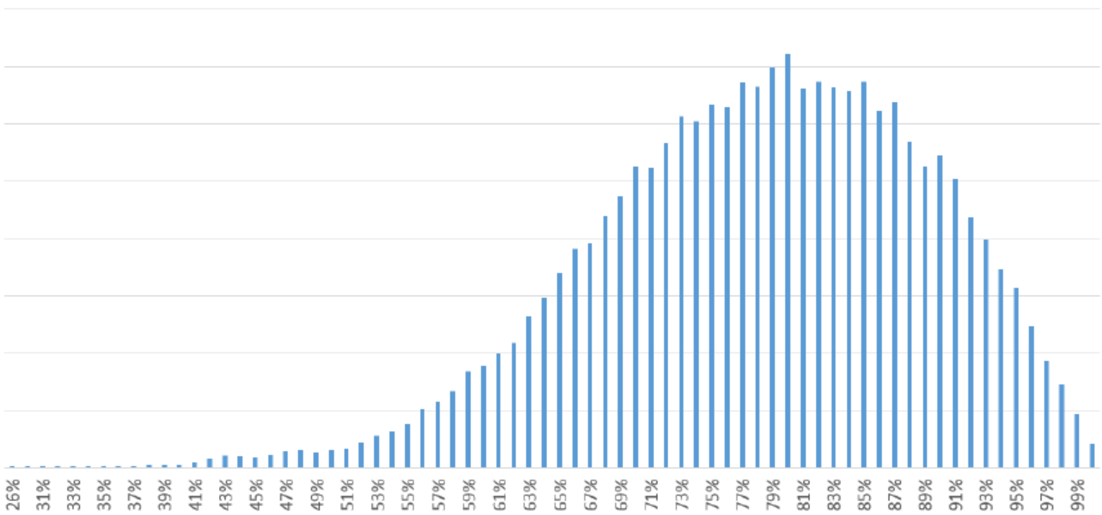
The enabled regulation is the light grey area in the background, the sum of the AGC signals is in dark grey and MW response is in yellow. The response is measured from the base point to base point trajectory (initialMW to totalcleared). The yellow line is also response, yet this time measured from the flat totalcleared target. The Regulation headroom is the difference between the unit MW and the regulation plus total cleared value (noting that AGC signals cannot be sent once the unit moves past this point).

What is noticeable is the yellow line (relative to a flat total cleared) is greater than the yellow area at the start of the interval and then they converge (which is to be expected as the trajectory moves towards the total cleared over the five minutes). What this means is of the frequency has been poor at the start of the interval, and regulation raise providers are already providing a full response to signals, there is no 'extra' energy to correct frequency. There appears to be misplaced assumption that at the dispatch interval boundary frequency will be at 50Hz and AGC signals will be zero.

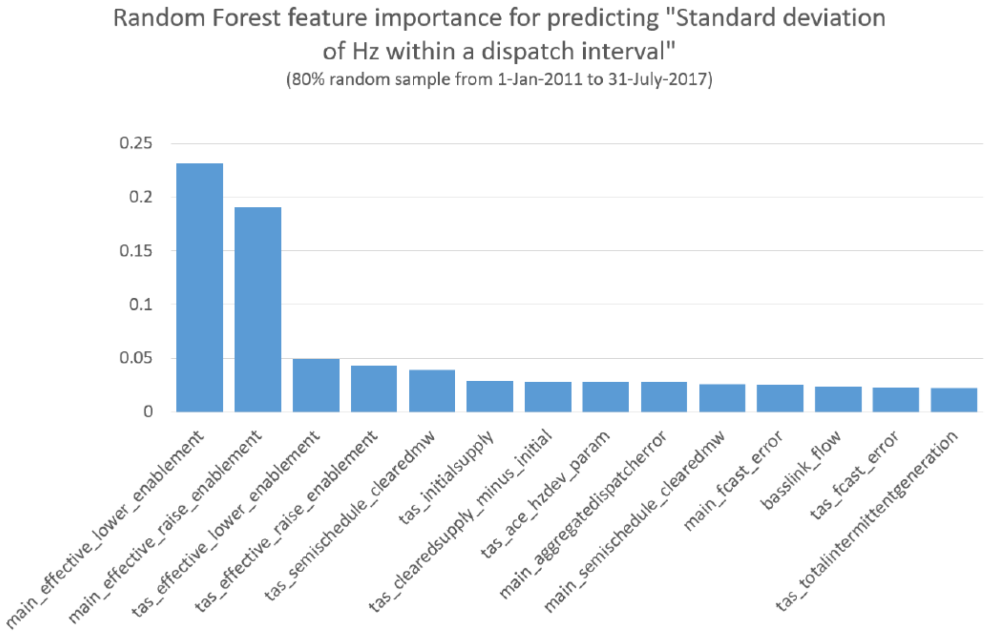


The inability for AEMO to be able to send signals and receive a response due to inadequate regulation headroom, results in numerous periods where the effective amount of regulation available to be signalled is less than enabled. For Raise services it is approximately 80%, however the distribution of these is skewed, with some 4second periods where the percentage is very low. This is shown in the following figure:

Distribution of Effective Raise Regulation as a Percentage of Dispatched Enablement
January to July 2017



Using a statistical technique that compares a series of measures, PD View attempted to identify whether effective enablement was causing the wider distribution of frequency. It found that it effective enablement (an inability to send AGC signals to units because of insufficient margin or headroom on those units at certain times within the 5 min interval), was, of the measures it compared, the most likely to contribute to the standard deviation of Hz within the 5 minute interval.

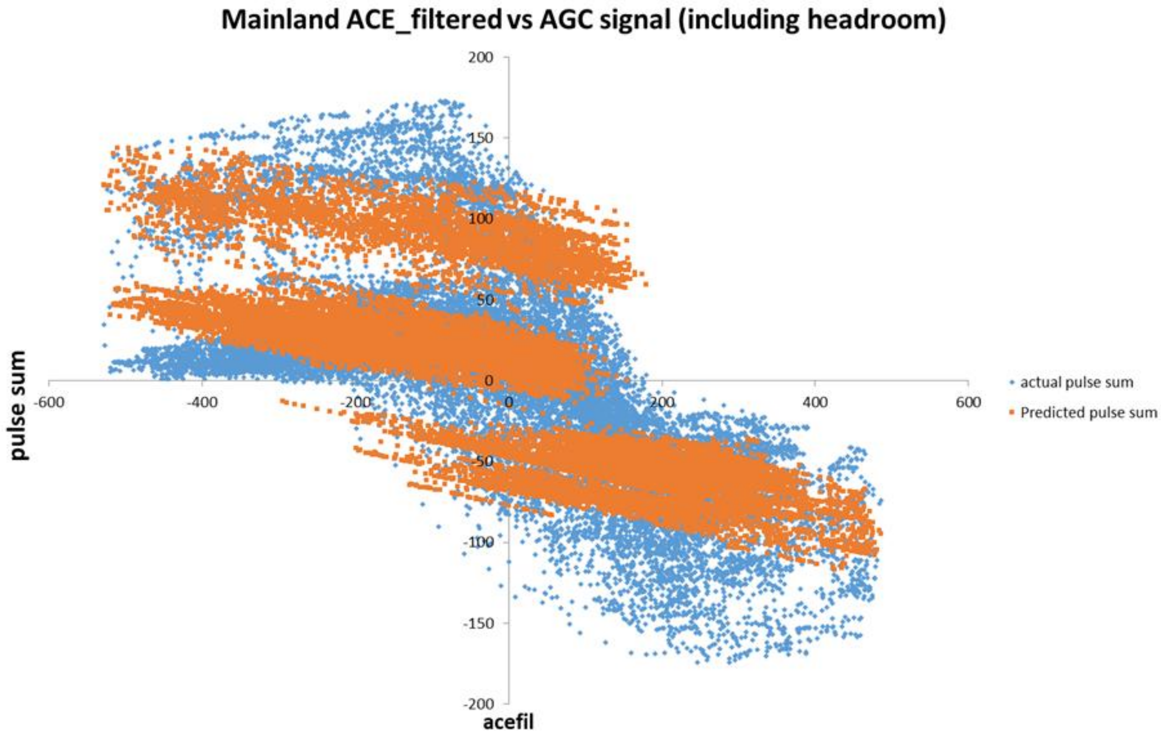


Earlier in the report it was highlighted that the AGC signals AEMO sends to generators appear less than are needed: this was shown by the back-calculated gain settings for Mainland units on the 1st April 2017. It seemed odd that ACEfil was high and yet the signals sent to generators were low.

PD View conducted a regression to compare the actual AGC signals with effective enablement or 'headroom' (an inability to send AGC signals to units because of insufficient margin or headroom on those units at certain times within the 5 min interval). It found that the problem is that, due to unit limitations, etc the signals sent to generators aren't as high as they should be: demand is higher than available supply in that 4 second period. This is proved, to some extent at least, by the regression results. By including headroom in the calculation, rather than just Acefil & AceInt, PD View was able to predict the pulse for the 1st April 2017 to 83% accuracy, rather than 47%.

Regression Y variable	X variables	R-squared value	Comment
Mainland pulse sum	Acefil & AceInt	47%	
Tas pulse sum	Acefil & AceInt	40.5%	
Mainland pulse sum	Acefil, AceInt, "raise headroom", "lower headroom"	83%	Significant improvement in fit with headroom include
Tas pulse sum	Acefil, AceInt, "raise headroom", "lower headroom"	70%	Significant improvement in fit with headroom include

PD View concluded a very simple regression model was fairly good at predicting what the AGC system will do once headroom, was included, thus making it a key limitation of today's system that is preventing it fulfilling its function of controlling frequency (by sending signals equivalent to ACEfil and ACEint).



Whilst there will be different ways to solve this problem, PD View provided the following high-level comments.

It is sensible to increase the volume of regulation service enabled, so that the amount required is that available to be signalled at the beginning of the dispatch interval. This can be done by adjusting the enabled volume to so the requirement is satisfied not just by enabled volume by adequate headroom (or effective enablement).

Additionally PD View provided the following observations in regards to this problem.

1) There is a problem with "headroom" which is the instantiations "availability" of regulation FCAS a unit can provide. "Headroom" is defined as:

Raise_Headroom_4sec = (NEMDE_target_5min + NEMDE_Raise_Enablement_5min) – CurrentMW_4sec

Lower_Headroom_4sec = CurrentMW_4sec -(NEMDE_target_5min - NEMDE_Lower_Enablement_5min)

In the equations above, *NEMDE target* and *Enablement* are outputs that NEMDE produces every 5 minutes. *CurrentMW* is measured by the SCADA/AGC system every 4 seconds. It should be noted that the above values are capped by a unit's bid enablement.

PD View believes that poor frequency control in the NEM occurs when "headroom" values are low. "Headroom" can become low due to two reasons:

a) The AGC system has already requested a large amount of regulation services and generators have provided it. Generators now have no “headroom” left as they are already providing the maximum amount of regulation services possible. Or,

b) If units are ramping during the dispatch interval, i.e. their end of interval NEMDE target is very different to their starting point (InitialMW), then the unit has a negative “headroom” value until such time it reaches a level whereby it can begin receiving AGC instructions to provide regulation FCAS. If the ramp amount is significantly greater than the Regulation Enablement amount then this can take a long time before the unit is available to provide regulation services. For example, if a unit is required to ramp down 25 MW in the energy market but is enabled for 5MW of RaiseReg service then the unit won’t be able to provide this regulation service until after approximately 4 minutes into the dispatch interval (5min – 5min*(5MW/25MW) = 4min) assuming the unit follows a linear trajectory as it ramps down. Specifically, limited headroom due to ramping is a problem when:

    i. A unit is required to significantly ramp DOWN in the energy market but provide RAISE regulation services.

    ii. A unit is required to significantly ramp UP in the energy market but provide LOWER regulation services.

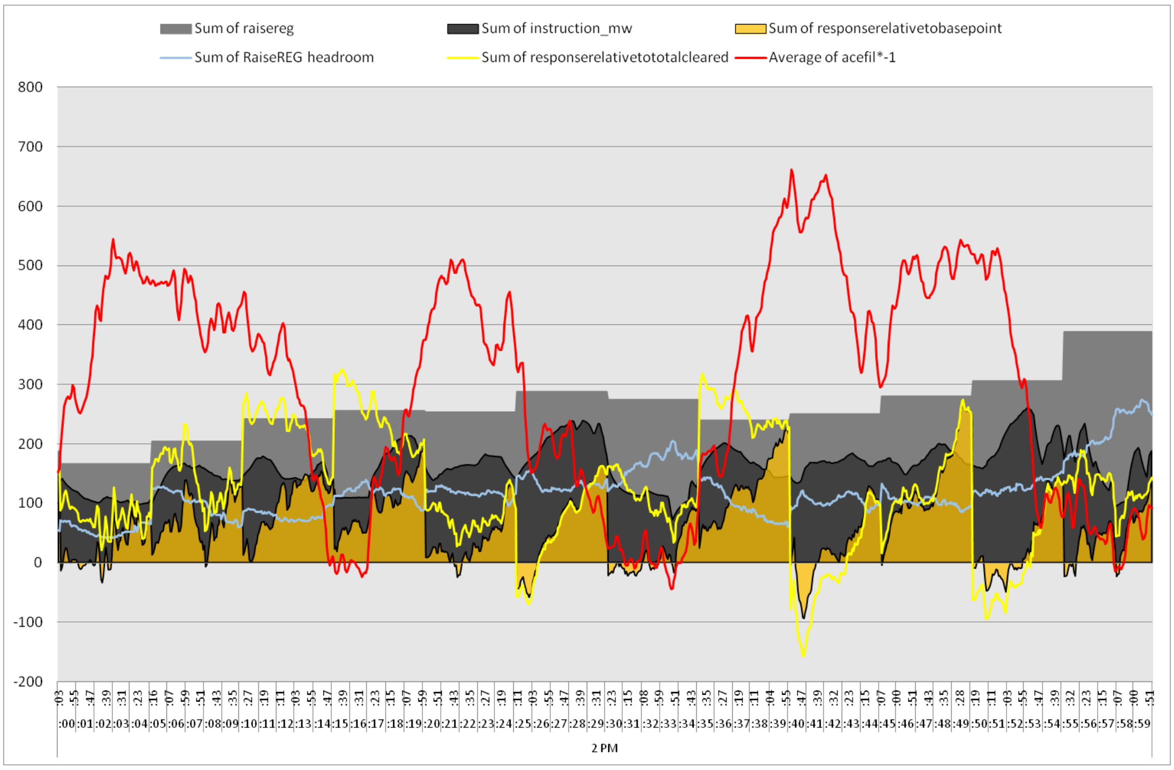
These two conditions occur more often than you would assume due to chance alone. They can occur when NEMDE co-optimises a bid (e.g. gives a unit a low energy target so it can provide RaiseReg) or when the AGC system has moved the unit into a different energy price band in the previous 5 minute interval and now NEMDE ramps the unit back into its cheaper energy band for the current dispatch interval while at the same time expecting it to provide the regulation service.

2) Point (a) above can be fixed by buying more regulation when required (linking enablement requirement to FI deficits). Point (b) can be fixed by applying a constraint to NEMDE that limits the amount of Regulation service a ramping unit can provide. How conservative this constraint should be is a decision for AEMO. The constraint should not only discount how much regulation a ramping unit can physically provide, it should also financially discount how much that unit is paid due to its low utilisation during a dispatch interval compared to a non-ramping unit. Also, a ramping unit that has the opposite ramping position to (bi) and (bii) should be rewarded for the extra/early provision of regulation services they provide.

4. Case study – 2pm 17th January 2017

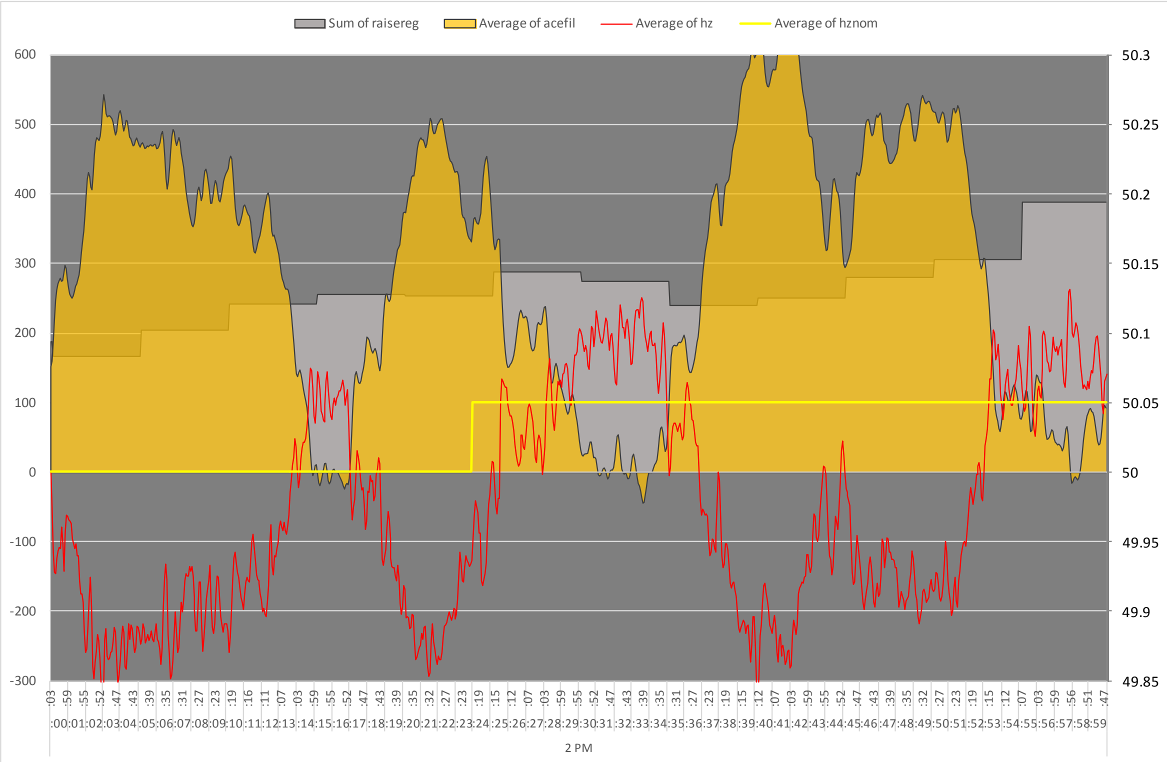
The following figures present data from 2pm to 3pm on the 17th January 2017, during this period the Mainland requirement was increased in response to accumulating time error. This was not corrected and further providers were enabled, until AEMO decided to implement a 400MW global FCAS constraint nearing the end of the hour.

The figure presents ACEfil*-1 as the red line and is positive showing low frequency. The enabled regulation is the light grey area in the background, the sum of the AGC signals is in dark grey and MW response is in yellow. The response is measured from the base point to base point trajectory (initialMW to totalcleared). The yellow line is also response, yet this time measured from the flat totalcleared target. The Regulation headroom is the difference between the unit MW and the regulation plus total cleared value (noting that AGC signals cannot be sent once the unit moves past this point).



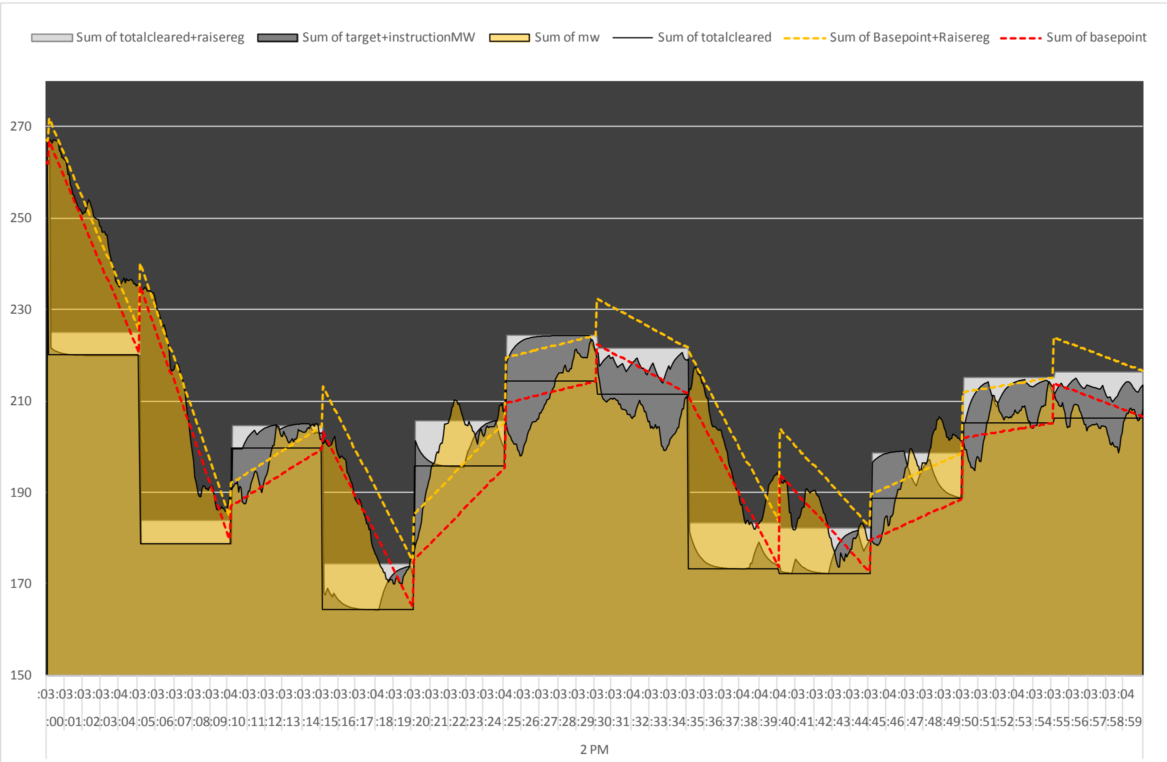
What is noticeable is ACEFil*-1 is high at times and, as expected, greater than enablement, however it is greater than enablement for persistently over the hour. AGC signals ‘instruction_MW’ are less than Raise Reg enabled. As indicated in an earlier figure the yellow line (relative to a flat total cleared) is greater than the yellow area at the start of the interval and then they converge (which is to be expected as the trajectory moves towards the total cleared over the five minutes).

A further figure presents ACEFil*-1 (yellow area), Hz (red line), Hz nominal which is used adjust the base frequency to correct time error (yellow line) in this case moving from 50 to 50.05Hz, and the quantity of enablement (grey area).

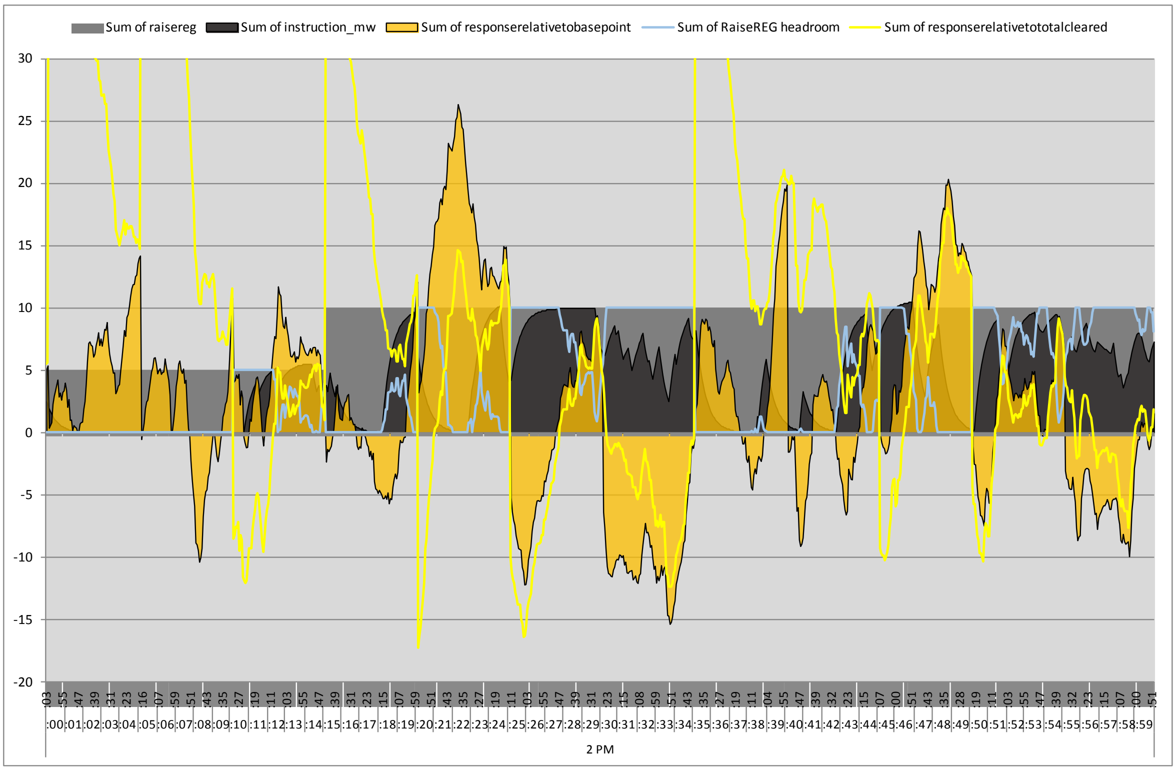


During this hour some units did not respond accurately to AGC instructions. This may be for different reasons, yet we shall highlight three and dedicate a whole section to the fourth.

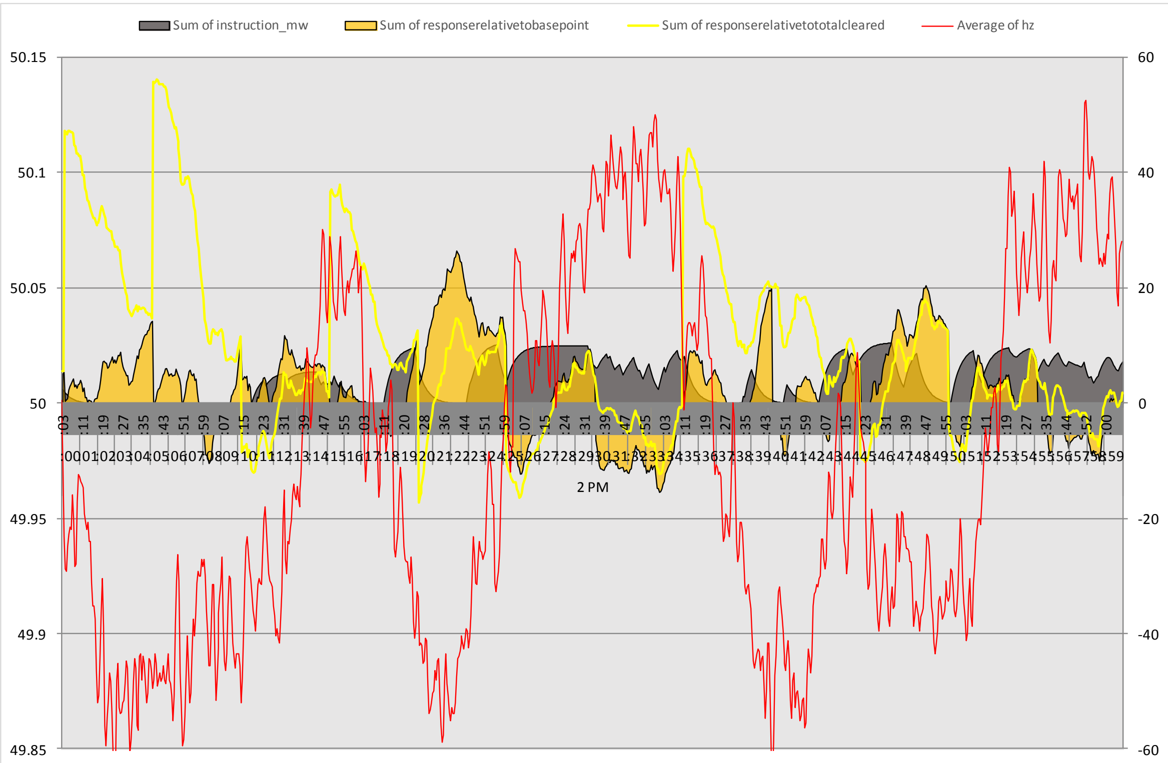
The **first** reason, which is **following frequency instead**, is indicated by MCKAY1. This unit changed base-point a number of times.



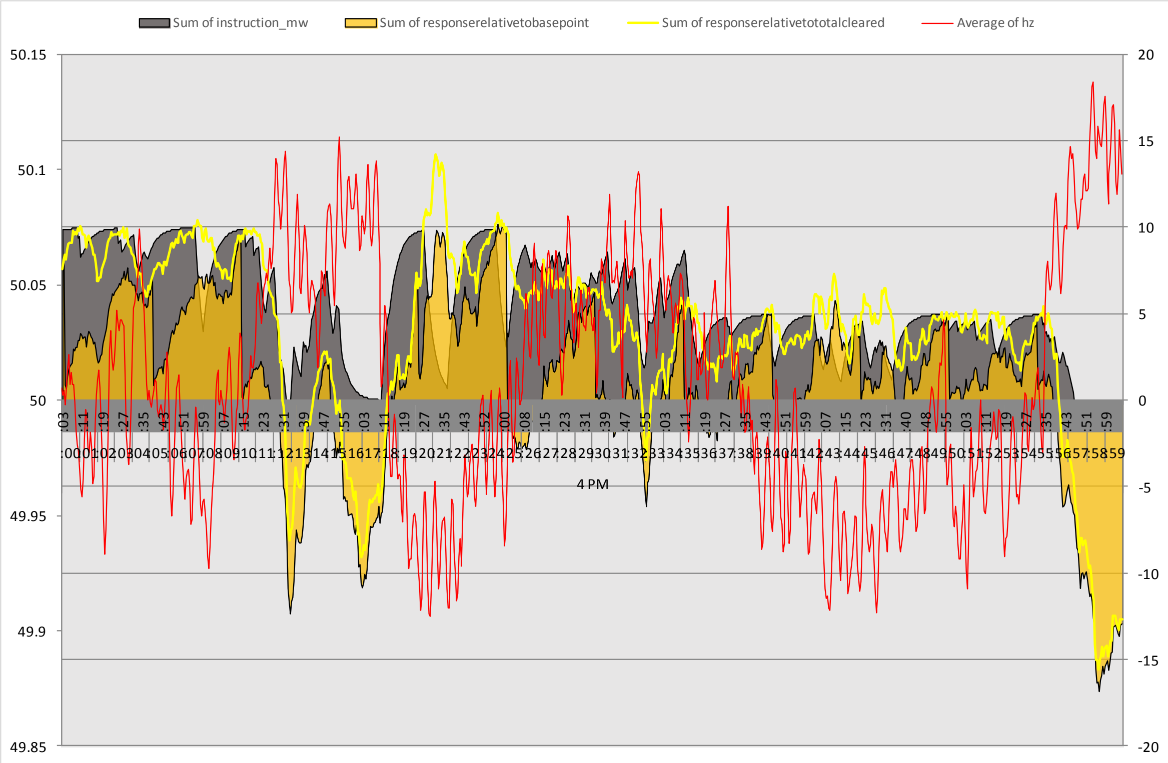
However, as we have previously discussed, this station appears to follow frequency to some extent, as its performance does not appear limited by the regulation enablement, as is shown below and sometimes acts counter to the AGC signals.



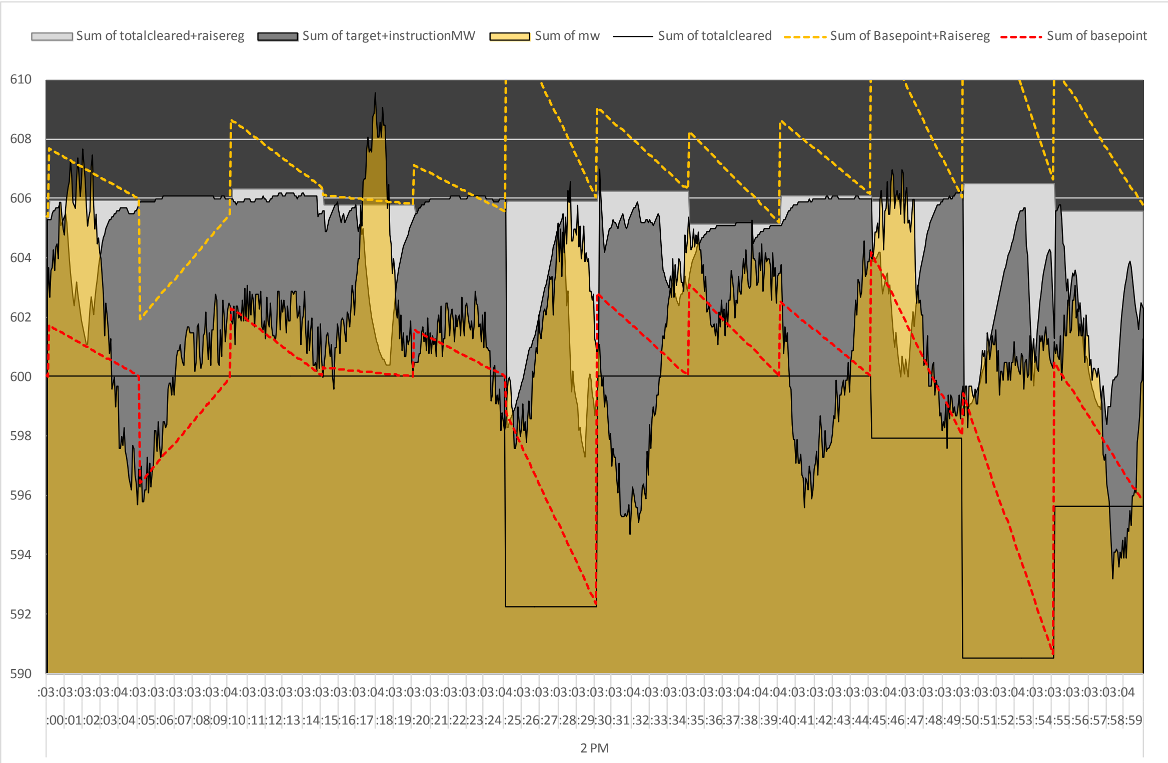
The following figure for MACKAY1 overlays frequency:



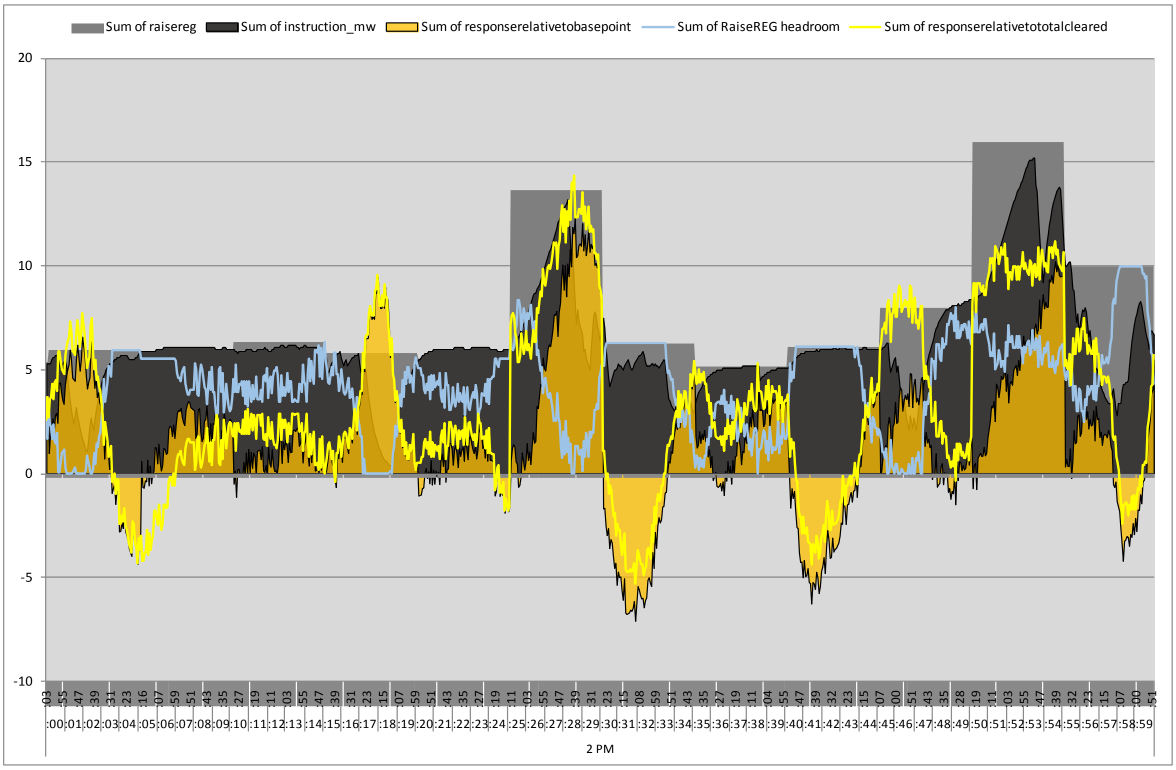
Similarly MACKAY1 for the next hour:



We include BW03, which is another unit that appears to follow frequency (to some extent at least) whilst it is moving to its target. This appears to limit the response to AGC signals from the regulation system.

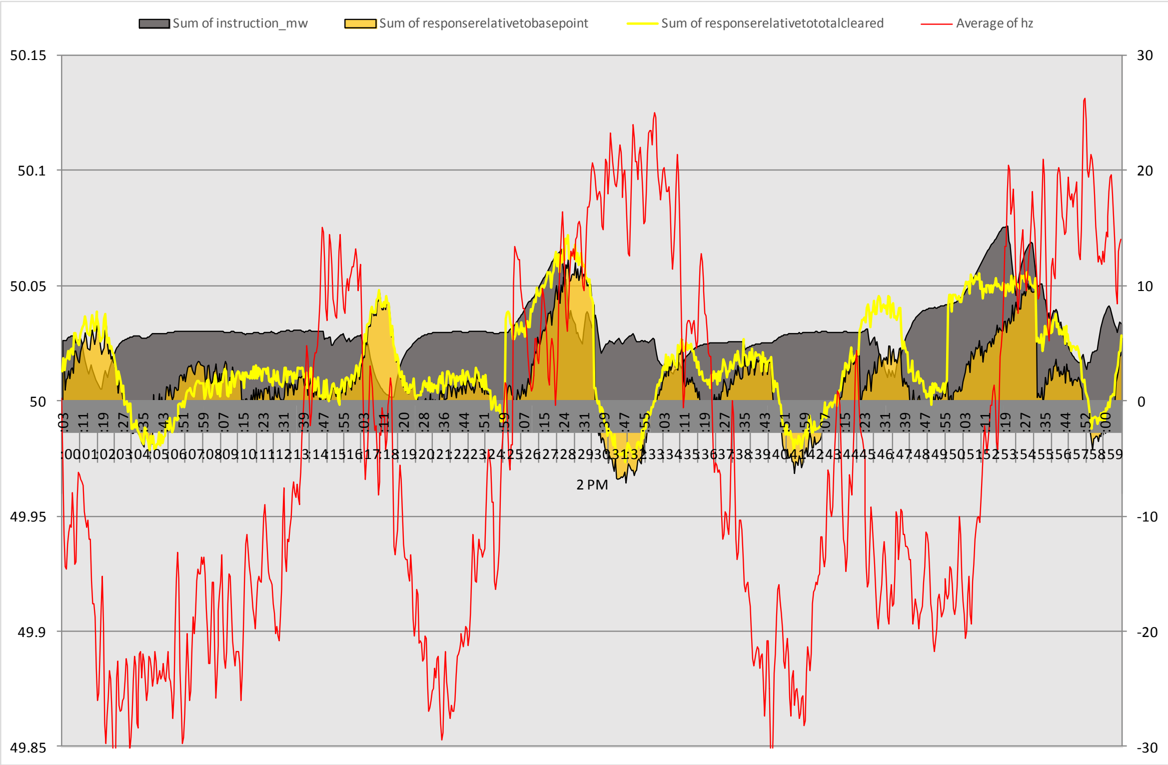


BW03 was highlighted when earlier discussing ‘grey-market’ FCAS. This occurred during the period where BW03 had Totalcleared of 600MW and 6MW of REG enabled.

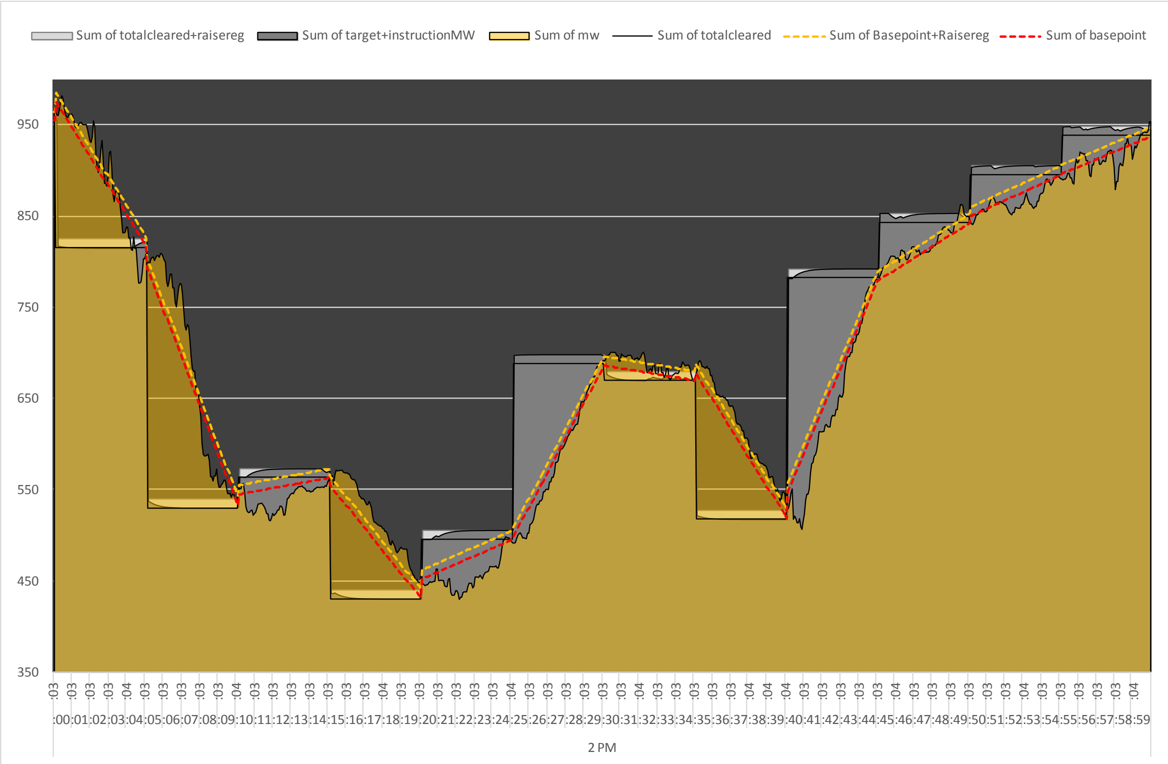


The figure below is noticeable because it indicates the unit responds to frequency rather more than the AGC regulation signals, especially for high frequency (when the AGC signals were in the opposite direction. However during periods of low frequency, when the AGC signals were in the same direction the unit is not respond to either particularly well.

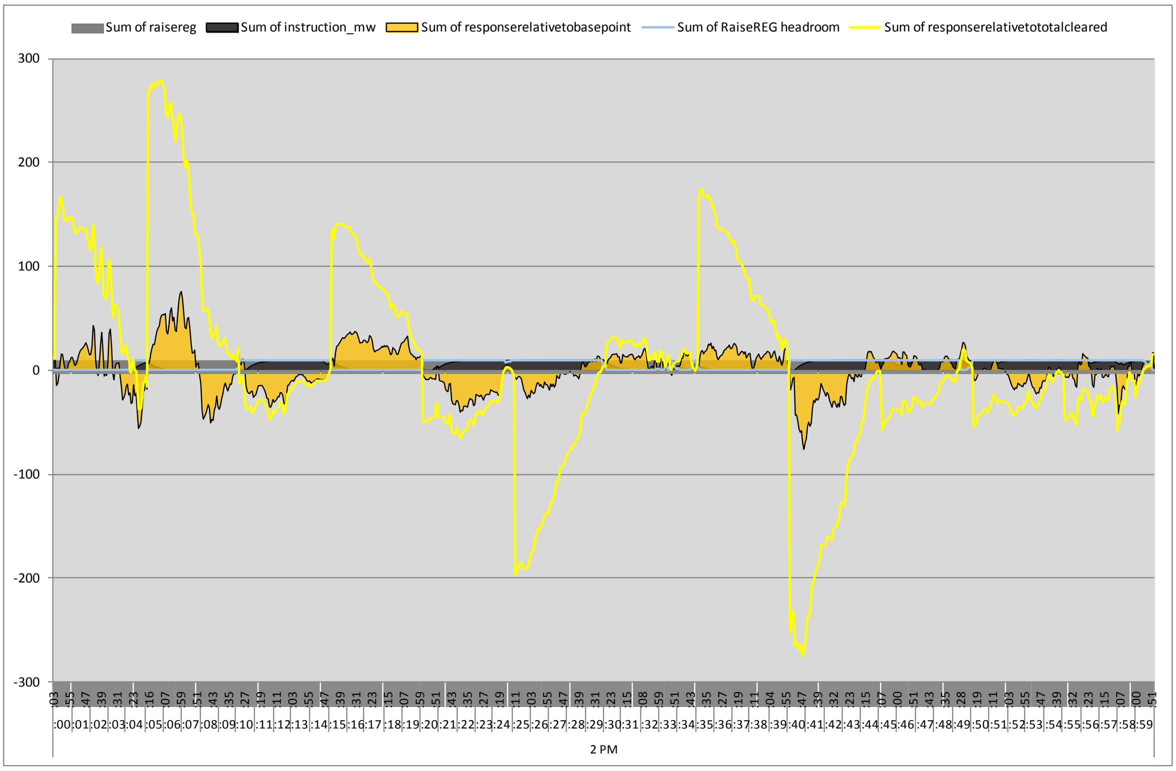
This suggests the unit simply wasn’t performing very well at the top end of its range, which is where transient limitations are more likely to limit unit performance.



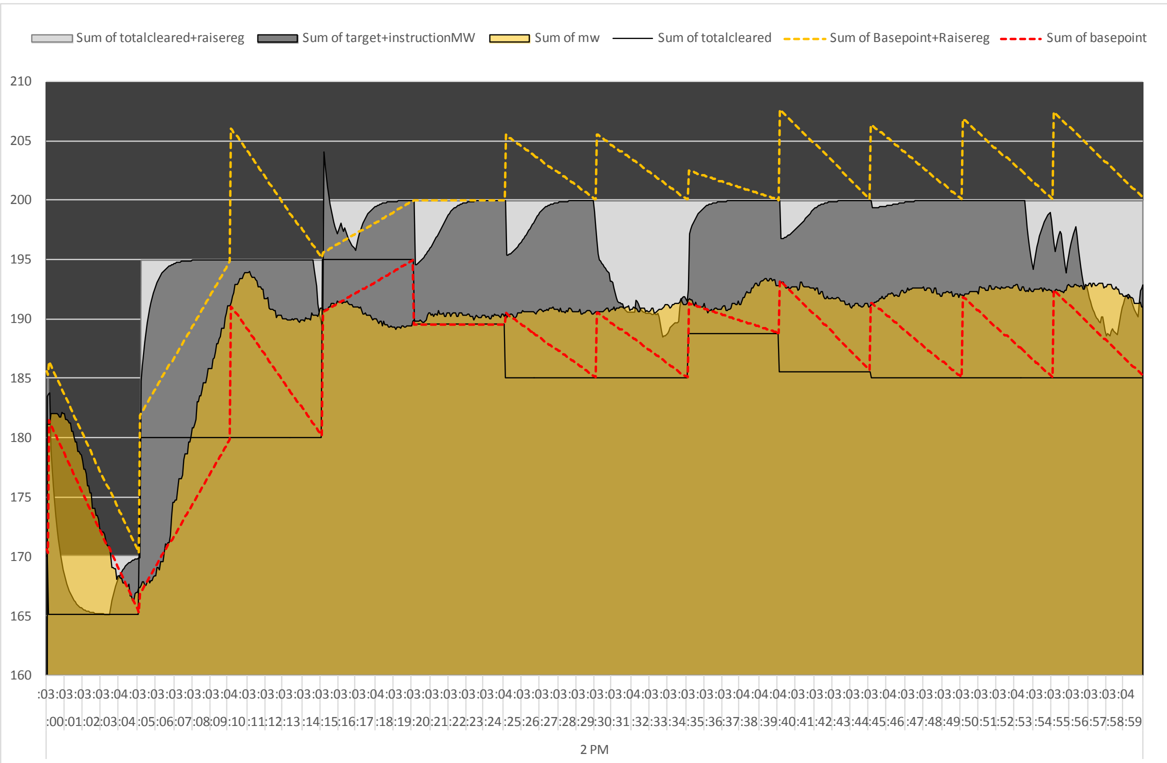
The **second** reason, which is **too busy ramping**, is indicated by MURRAY, which is an aggregated unit with high ramp rates. The unit base points changed rapidly throughout the hour. With changes in base point of over 100MW the unit's 10MW RaiseReg enablement becomes swamped by the unit movements. In short, Murray contributed to the need for Regulation services during this period, whilst being a Regulation provider.



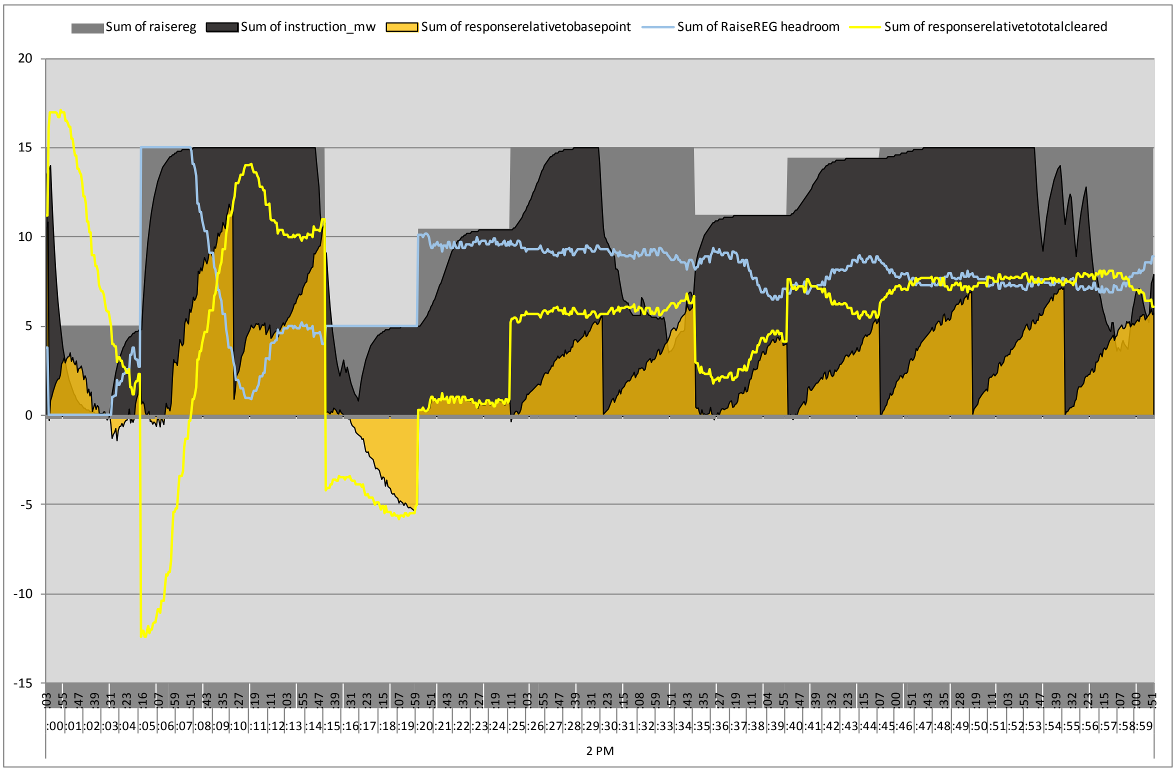
The following chart for MURRAY shows the movements of during the hour resulted in the unit's deviation to target (yellow line) or to the base point to base point trajectory (yellow area) acting contrary to the unit's regulation AGC instruction.



The **third** reason, which is **unit limitations**, is indicated by TORRB3, but could easily apply to a number of units from time to time, especially near the unit's limit.



Eventually the unit's availability was rebid to 190MW, consistent with the prevailing unit performance.



The **fourth** reason, which is **AGC system interoperability**, deserves its own section and follows.

5. Can each system regulate the frequency of the other?

The Basslink frequency controller adjusts load in proportion to frequency, ‘equalising’ frequency across systems (at least within the NOFB).

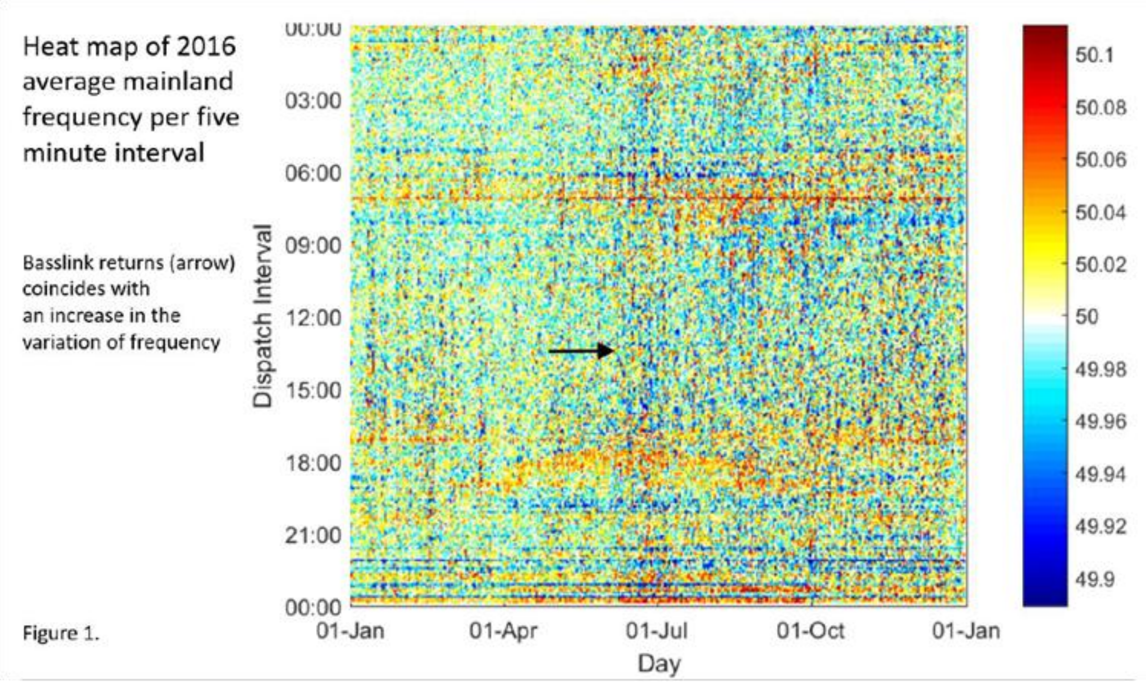
Given providers on the Mainland are used to control frequency in Tasmania (and vice versa) the different proportional MW/Hz, gain settings and the application of the filtered time constant all act to change the signal given to the unit in one system that is supposed to be correcting frequency in the other.

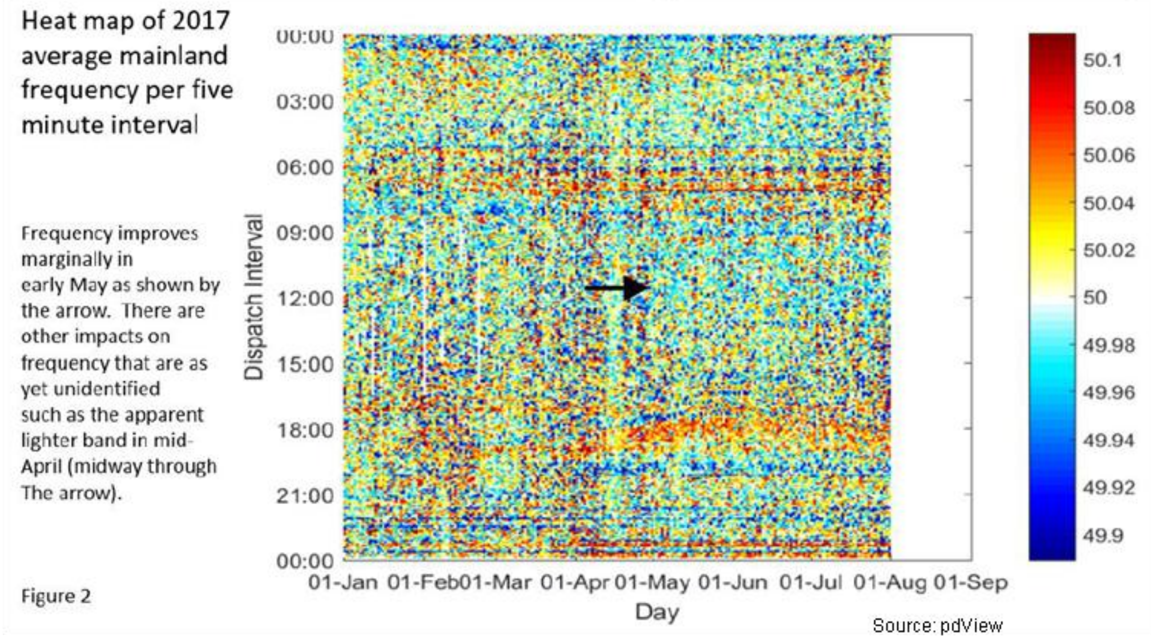
By amplifying the signal to Tasmanian units enabled for Regulation services, these units should provide energy in excess of the ACE for the local system, with this energy then transferred through Basslink to the Mainland to correct frequency. However this has been found not to occur[16], whether this is as a result of the proportional calculation of ACE, gain settings, time constant filtering or Basslink’s frequency controller is unknown.

It has been noticeable that the standard deviation of Mainland frequency has occurred with the increasing enablement of Tasmanian units.

The following heat maps indicate the problem has, to some extent at least, arisen since the return of Basslink.

[16] PD View - An analysis of AGC relative effectiveness of Tasmania versus Mainland, and station performance





CS Energy has also seen time error accumulate during periods when AEMO has dispatched a significant amount of Tasmanian Regulation services for global constraints.

This was explored by PD View in its report to CS Energy, which showed the different sensitivity of the Tasmanian AGC system ('AoH') and gain settings resulted in a proportionally lower signal being sent by AEMO to Tasmanian units enabled to regulate the NEM frequency. This resulted in frequency deteriorating, time error accumulates, then a time error correction constraint being implemented to 'fix' the problem.

AEMO has taken actions to reduce the use of Tasmanian regulation services to control global frequency[17] and mainland time error[18] because of the performance of the AGC

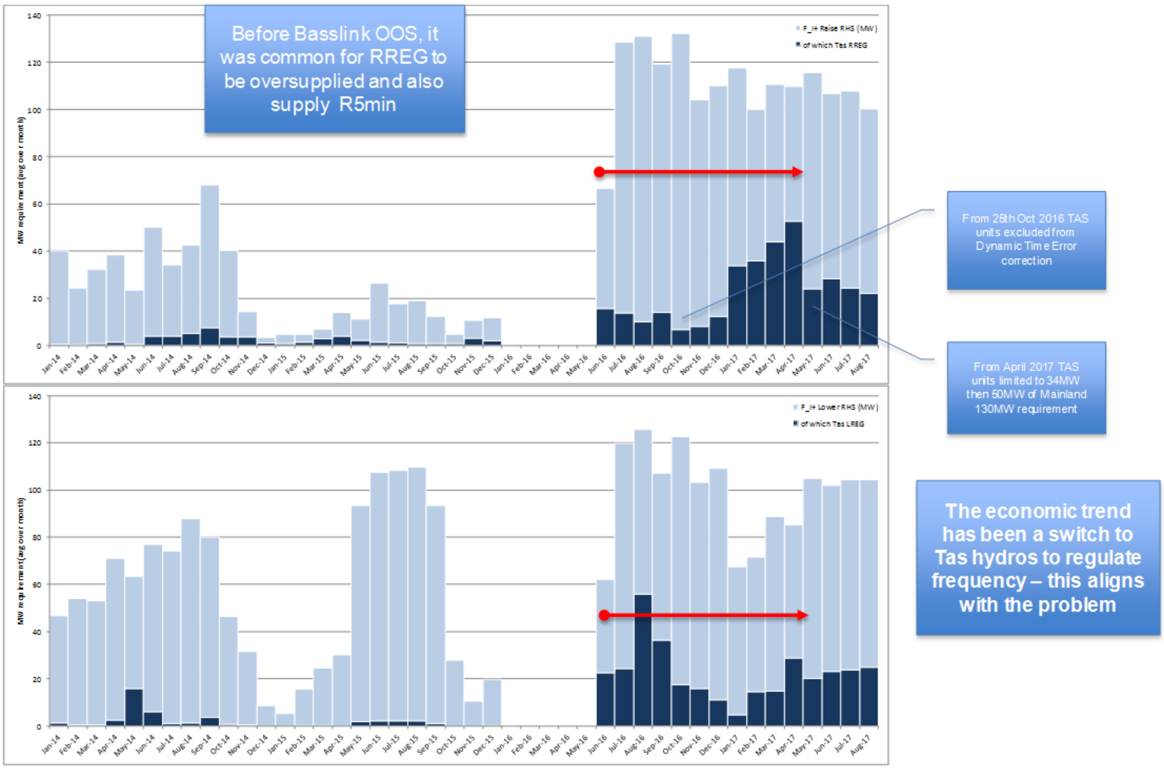
[17] From April 2017 Tasmanian units limited to a share of 34MW initially, and then increased to 50MW, of the Global 130MW FCAS requirement: i.e. 80MW of the 130MW (62%) Global requirement must come from Mainland units.

system and the effect of the Basslink frequency controller. CS Energy considers these measures to be palliative in nature and will not resolve the underlying control system issues.

That Basslink returned would not change Mainland frequency considerably, given the size of the system. It should therefore be noted that the problem has coincided with increasing enablement of Tasmanian units for Regulation services for Global constraint equations (F_I, when Tasmanian services can help regulate Mainland frequency).

The following figure presents monthly average values of dispatch for regulation services fomr Mainland providers and Tasmanian providers at ties when a 'Global' FCAS requirement was binding in dispatch. Typically the requirement globally is 130MW for raise and 120MW for lower FCAS. Prior to July 2016 there was rarely a 'Global' market for regulation services on the Mainland. This was because there was nearly always too much Regulation Raise FCAS dispatched to satisfy the requirement for delayed 5 minute FCAS, such that the regulation requirement did not impose a cost.

Post July 2016 the Regulation FCAS constraint requirement bound increasingly setting a price on these services. This means there was also less available, (only 130MW) to be sent signals by the AGC system. Increasingly, due to economic reasons that we will explain later in this report, Tasmanian units started to be dispatched as increasingly large synchronous units in NSW and QLD were dispatched for energy.



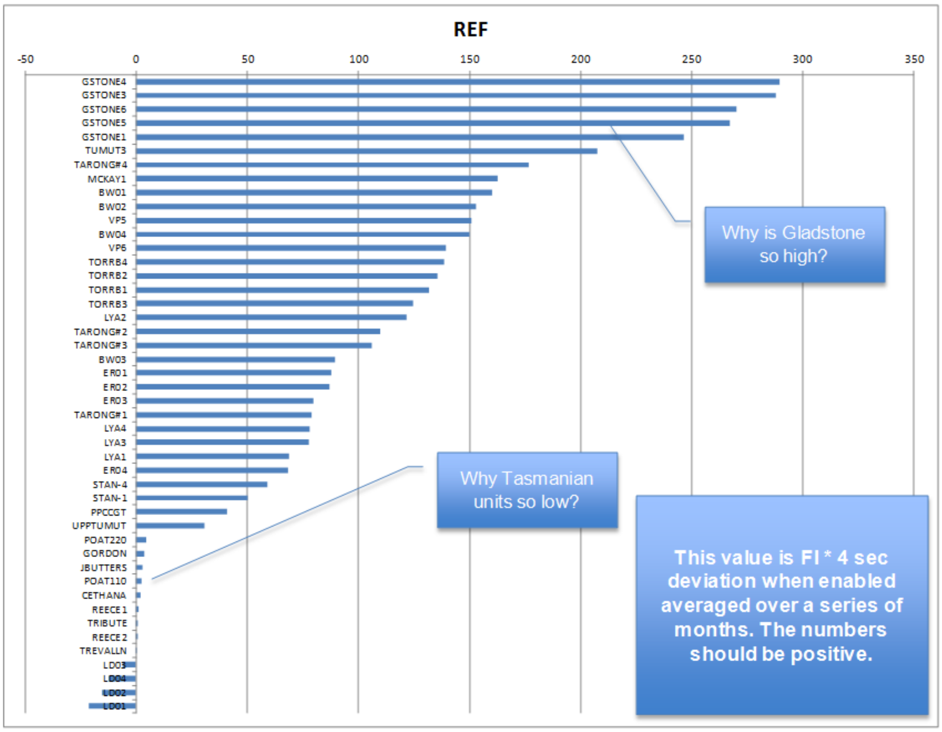
The following figure uses AEMO's monthly causer pays data from May 2017 to April 2017 inclusive. CS Energy used the Raise enabled factor (REF) averages for the sample periods. Because these averages are based on the whole sample period – 28 days (less excluded contingency periods), the averages have been reweighted to the proportion of

[18] 25th October 2016, changes in AEMO's FCAS constraints required supply from units only on the Mainland (not Tasmania) upon time error correction on the Mainland.

time the unit was enabled for RREG. Units are excluded if they provided less than 500 DIs of enablement in the month.

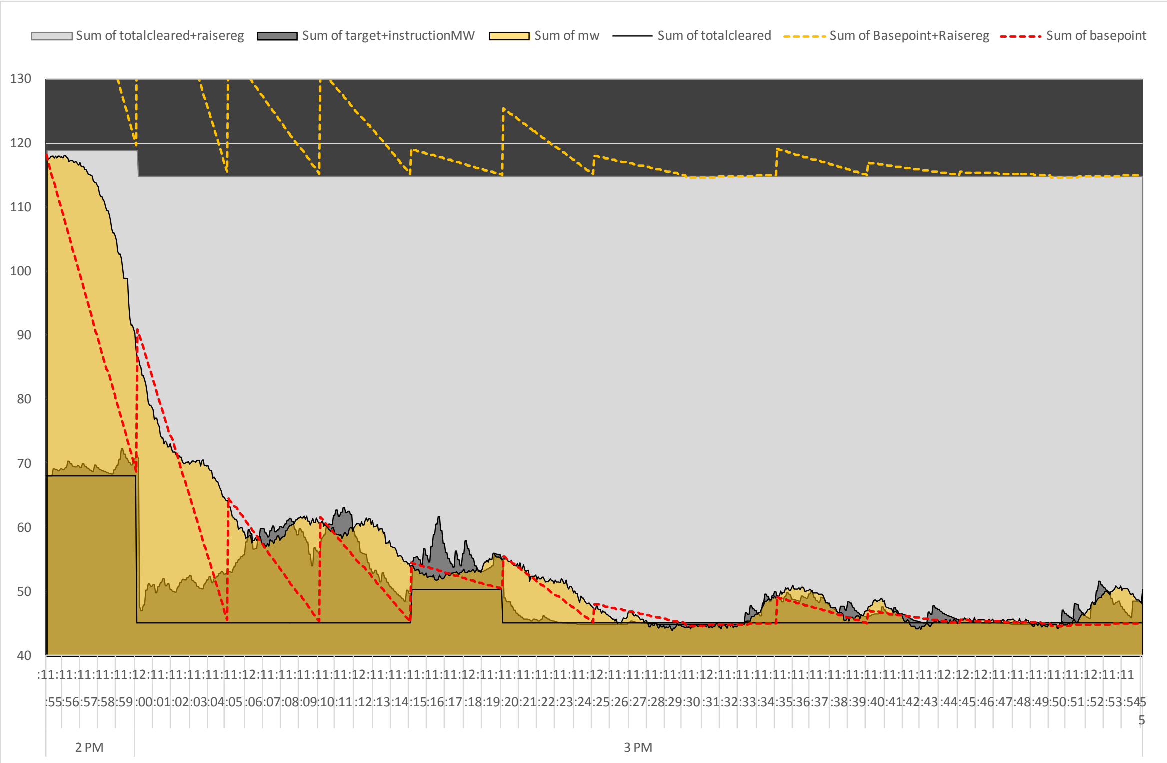
Units providing Regulation services should have a high REF number. This is because the factor is the Frequency Indicator * unit MW deviation from its target. One would expect the REF number of vary depending on the volume of RaiseREG that the unit was enabled for. This may explain the higher Gladstone values compared to other units, yet it would not explain the discrepancy in unit performance for the Tasmanian units, which would indicate they were not responding to FI. This means Tasmanian units, when enabled for Raise services either did not receive or did not respond to AGC signals when enabled for Raise services.

DUID	REF
GSTONE4	290
GSTONE3	288
GSTONE6	270
GSTONE5	267
GSTONE1	246
TUMUT3	207
TARONG#	177
MCKAY1	163
BW01	160
BW02	153
VP5	151
BW04	150
VP6	139
TORRB4	139
TORRB2	136
TORRB1	132
TORRB3	125
LYA2	122
TARONG#	110
TARONG#	106
BW03	89
ER01	88
ER02	87
ER03	80
TARONG#	79
LYA4	78
LYA3	77
LYA1	69
ER04	68
STAN-4	59
STAN-1	50
PPCCGT	41
UPPTUMU	31
POAT220	4
GORDON	3
JBUTTERS	3
POAT110	2
CETHANA	2
REECE1	1
TRIBUTE	1
REECE2	1
TREVALLN	0
LD03	-6
LD04	-12
LD02	-16
LD01	-21



The figure below is REECE1which was enabled for 70MW of Raise regulation. There are few AGC pulses sent to the unit by AEMO.

For further information please refer to the attached reports by PD View.



In summary, CS Energy has observed periods of poor regulation of global frequency by Tasmanian units, accumulation of time error on the mainland, and then increased dynamic requirements to correct time error on the mainland, with AGC signals being sent to providers which oppose the prevailing frequency – e.g. signals to increase load for Raise Regulation providers when frequency is high. This occurrence has been discussed by AEMO.

AEMO and DigSilent suggested signals being sent to Mainland Regulation providers to restore time error as counter to good frequency control[19].

[19] AEMO, Review of the Frequency operating standard , Stage 1 – request for advice, 18 August 2017, pp.6

6. Monitoring dispatch forecast error.

Under the Causer Pays Procedure AEMO calculates the average performance over 5 minute periods of elements of the NEM system, using 4 second data, against a target trajectory. AEMO assess the performance of the regional demand forecasts, which is called Load Forecast Error ('LFE'). Given a Load Forecast cannot be enabled for Regulation services, the relevant calculation is the Lower and Raise Not Enabled Factors 'LNEF' and 'RNEF'.

The LNEF for the LFE is generally, for most regions, less negative than the RNEF for LFE. This would suggest that AEMO is under forecasting, therefore causing low frequency and a need for raise regulation services.

Corroborating this is that the LNEF is positive for Scheduled Units and RNEF highly negative. For example a unit with a constant offset such as Condamine (below target) would have a worse RNEF than LNEF because of this, which is true of the data. These analyses indicate ACE caused by under forecasting, higher Frequency Index ('FI') AGC signal values for Raise Regulation services caused by LFE.

We posit that 4 sec data in the Causer Pays process suggests some under forecasting by AEMO, creating higher need for AGC signals being sent to Raise regulation providers. Causer Pays data suggests that the 5 min dispatch forecast and (maybe poor) units' efforts to keep up with this are contributing to low frequency.

Whilst AEMO must have detailed processes to review its dispatch forecasting performance, the Causer Pays calculations should be used to incentivise it to improve. This is because the MPF calculations for Participants' scheduled generators are designed to place a cost incentive to improve performance in following trajectories. Similarly the MPF calculations should provide AEMO with incentive to minimise the need dispatch forecasting creates for regulation services.

The data however is not ideal. This is because, prior to July 2017, AEMO had a calculation error in the CPP related to Smithfield Energy Park (a 160MW gas fired generator in NSW) which erroneously resulted in the NSW demand forecast perversely being presented under the CPP as *helping* to regulate frequency (which obviously it can't). This increased the factors (and costs) for all other SCADA measured generators. CS Energy made AEMO aware of a potential error in the NSW calculations during the consultation on the Causer Pays Procedure.

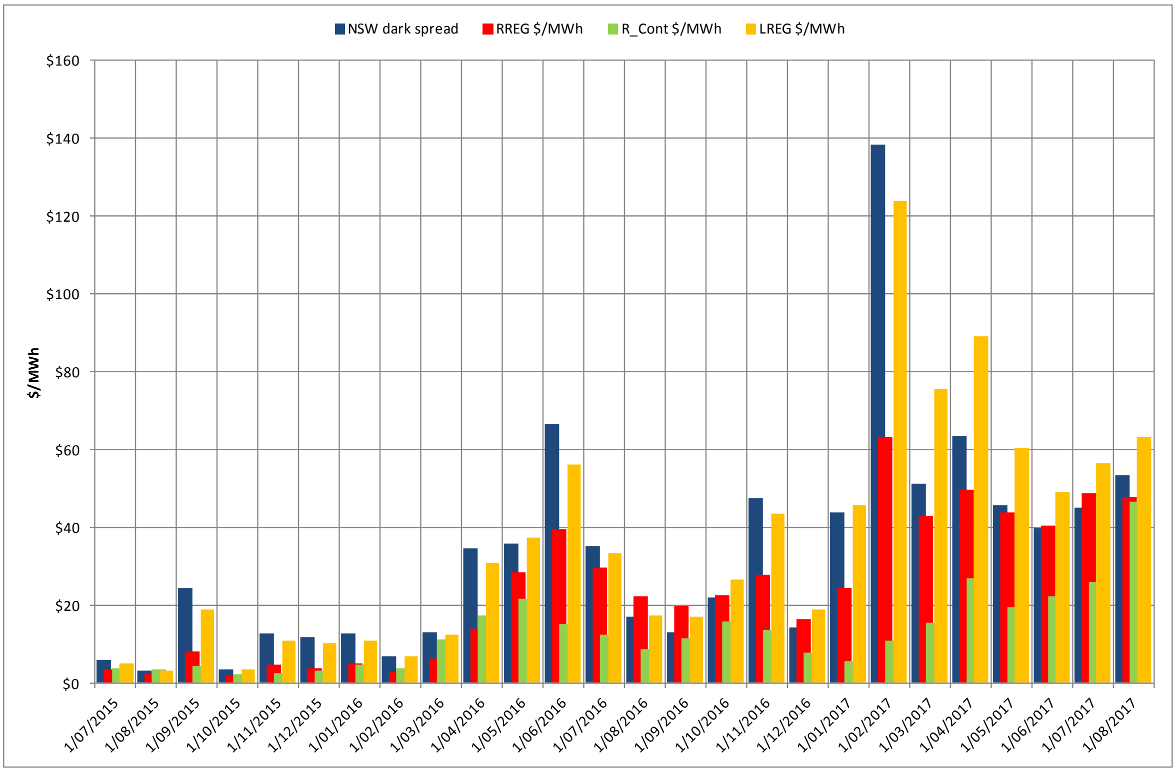
Is it getting too expensive to regulate frequency?

AEMO suggests in its advice that, in the face of more demand for frequency services arising from sudden changes in generation, it would be more efficient to use the existing contingency FCAS that is enabled rather than buy more regulating FCAS.

CS Energy is a provider of Frequency Control Ancillary Services ('FCAS') through the Gladstone and Wivenhoe power stations. Callide B is also registered for services, but is not competitive, therefore rarely enabled for any services. Our two largest facilities, Kogan Creek and Callide C (owned in part through a joint venture company), are not registered for FCAS: even if they were, they would rarely provide services to AEMO in today's market, but could in the future. CS Energy also pays for FCAS services through activities at the aforementioned power stations and the Boyne Island aluminium smelter.

Over the last two years CS Energy has seen a marked turn around in the NEM. The closure of Wallerawang, Hazelwood and Northern power stations and reduction of gas-fired generation volumes (which had been burning ramp up gas prior to CSM-LNG export plants coming on line) has improved the economics of coal fired generation and placed a premium on available capacity to control frequency. This has increased FCAS prices, but in line with expectations.

CS Energy is of the opinion that the FCAS markets usually trade at a discount to the profits available for being dispatched for energy. The following figure presents the expected profit, or 'spread', on $/MWh basis for a coal fired generator in NSW, pricing coal at 90% of the NEWC6000 index with a heat rate of 10.5GJ/MWhso (dark blue column).



The spread is compared to the payments for Raise Regulation (red column), which includes a 25% utilisation rate, and the payments on offer for Raise Contingency FCAS (green column). Lower Regulation (orange column) is calculated as pool revenue *(1-25% utilisation rate) plus enablement payments.

Please note the chart doesn't include "wear and tear" costs, efficiency losses, etc. that arise from changing load. Lower contingency is not shown for the reason that these markets generally clears for a few cents and are dominated by Loy Yang B.

The chart indicates at a high level that prices in the FCAS market have moved with pool prices: this is because, for raise services, the reserve required from synchronous generators has become more valuable and there is an opportunity cost associated with not selling energy.

This link was not so marked with contingency, probably due to the greater diversity of suppliers (with standing plant and loads, with lower opportunity cost, able to provide some response). However this has changed in recent months.

The economics involved in Lower Regulation are premised on losing pool revenue when utilised, incurring wear and tear yet being compensated by the enablement payment. This service has attracted a premium as generators are risk adverse and don't want to supply lower regulation at times of higher pool prices, when there is a risk of higher utilisation (typically in the morning ramp up period).

It is unclear that there is any particular requirement for Regulation FCAS costs to be minimised, given they do not appear to be unreasonable under current market conditions. If AEMO was to buy more Regulation FCAS, it does not appear unreasonable to assume this would follow costs of the energy market.

Using contingency in lieu of regulation FCAS will dull marginal price incentives, exacerbating the problem

In any case the costs of Regulation FCAS are allocated to causers, using a "Causer Pays" principle. This process allocates the costs of Regulation FCAS to causers using 4 second SCADA data, an although subject to some averaging and netting approaches which should be improved to sharpen marginal price incentives, at least encourages participants causing deviations in frequency to improve their unit performance.

Note that under a Causer Pays approach, which is based upon principles not dissimilar to our ideal world solution in Appendix 1, operators can decide whether their actions in adversely affecting frequency are costing them more that the marginal benefit they receive – in short the users can determine whether or not they should "make or buy" good frequency control depending on their relative competitiveness.

To be clear costs of Regulation FCAS increasing is not necessarily a bad thing – it may be efficient to incur these costs so certain generators, loads, etc. don't have to more accurately forecast, curtail, diversify or control their loads, because these actions may come at a cost that is greater than the cost of the additional Regulation FCAS.

If AEMO buys less Regulation FCAS for sudden changes in load of wind farms and solar PV, the costs will be lower and the Causer Pays approach will not allocate costs to these participants. Instead the costs of these sudden deviations will simply be smeared across all generators or allocated to consumers (because contingency FCAS charging rather than causer pays will be used). The result being that these generators will receive an implicit subsidy from consumers as they will obtain the marginal benefit from unrestricted unit output, yet not face the marginal costs of doing so. All else being equal, these poor incentives will encourage in decisions, at the margin, for solar PV and wind farms, that deteriorate frequency and increase cost when it could have been avoided.

The above discussion is rather irrelevant given we don't consider sudden, expected changes in load of PV and wind warm in less than 30 seconds to be occurring as frequently as AEMO' advice to the panel would lead one to believe.

However, it is our understanding that AEMO has discussed the option of changing contingency FCAS so that it provides response at +/-0.05Hz. By doing this contingency FCAS would become a regulating service.

If contingency FCAS were to become a regulating FCAS service for managing significant variations of solar PV and wind farms, or any other generators for that matter, within the 0.05Hz symmetrical, the dynamics of these markets will change.

Participants usually sell 6 and 60 second contingency services through governor control with symmetrical dead bands.

CS Energy has the Gladstone and Callide B dead bands set at +/-0.1hz symmetrical, in order to ensure it provides the adequate response as required under the MASS. This is tighter than the NOFB, because in order to satisfy the MASS the generator most continue to restore frequency to 0.1Hz. The units can't limit the response to whether or not they are enabled – they will simply respond to changes in frequency in proportion to the change in frequency outside these dead bands. Unlike Regulation FCAS, The assumption is that these units will not have to respond frequently as the response is only required infrequently if a unit trip occurs.

For completeness, Kogan Creek is +/- 0.5 Hz in non-reg mode and +/- 0.1 Hz if directed to select reg mode. Callide C dead band was changed to setting of +/- 0.15 Hz in August 2015 and Wivenhoe is also +/- 0.15 Hz. Of the three stations only Wivenhoe is registered for FCAS.

We recommend the Panel discuss with AEMO how it plans to use contingency FCAS, (for changes in generation as defined under the new FOS), when high frequency events occur. This is because the contingency requirement is very low and sometimes zero. The Lower 6 second and 60 second requirements are based on the largest load that could trip in the system (a smelter), which is typically 400MW.

Gladstone units are rarely enabled for lower 6 or 60 contingency FCAS as the requirements set by AEMO are very low, to zero and in any case the price is only a few cents. CS Energy would consider not offering lower FCAS services, changing the symmetry of the dead bands, thus removing governor control for high frequency events (which would require an unnecessary reduction in load that we are not compensated for) by setting the dead bands wider than 0.1Hz.

Appendix 2: Our ideal solution

Presently there are market failures with the current NEM auction design because it fails to price the scarcity of inertia, thus leading to increasing Rate of Change of Frequency (RoCoF). It also fails to dynamically procure, price and allocate the costs of real time deviations that causing changes in frequency, managed using regulating and contingency frequency services. The specification of FCAS services, although creating a market, are themselves market failures as they reduce the number of available suppliers, require a central controller determining quantity and require audit, verification and enforcement to ensure quality. The FCAS arrangements are far from ideal.

In an ideal world, the control of frequency would be decentralised and the market would determine the appropriate quantity (quality of frequency) depending on the cost. This trade off is suited to a market, with participants responding to marginal price signals, rather than a regulated agency, such as AEMO. The way to do this would be to calculate, using measurement and control technologies, real time quantities or 'deviations' and charge these on the basis of how they affect system frequency.

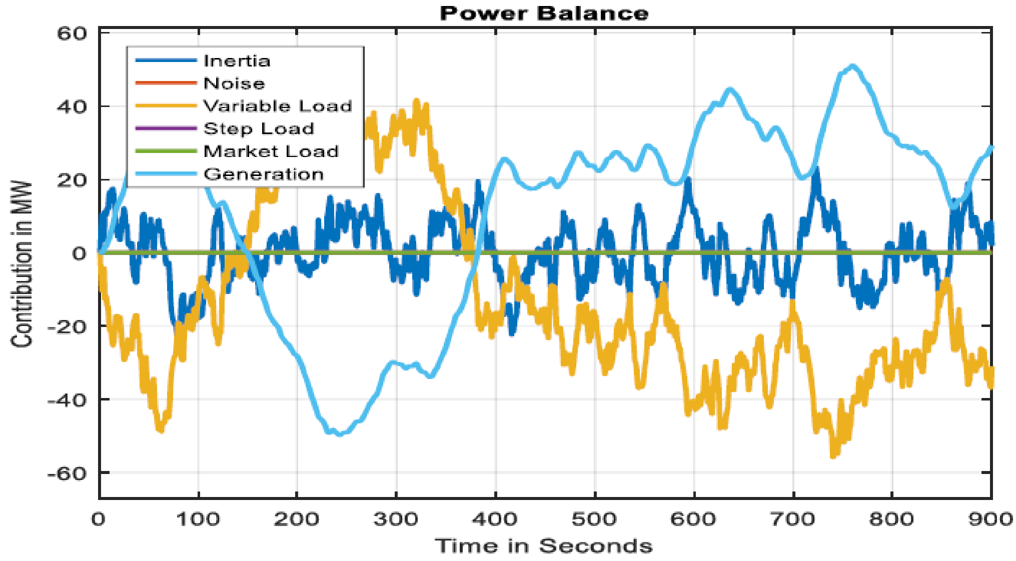
> Inertia is a valuable product because it decreases the RoCoF, thus allowing frequency response from slower moving, standing generators or switching loads. In so doing, inertia allows frequency response to come from a deeper pool of providers, increasing competition and reducing costs (depending on the cost of inertia itself).
>
> Ideally the NEM should be able to optimise the level of inertia (and with it RoCoF) and the balance of the fast or slow frequency response. It doesn't today because inertia is explicitly deducted under the Market Ancillary Services Specification ('MASS') from the quantities of fast, slow, and delayed Frequency Control Ancillary Services ('FCAS').

We are of the opinion that costs to consumers will be minimised through the allocation of frequency control, including optimising RoCoF and contingency services, to market participants. The optimal balance between inertia (RoCoF), fast frequency services and delayed services can be achieved by bringing all these services together, integrated into energy prices (settlement amounts) that are then adjusted for system frequency. By doing this, competition will set prices at an efficient level, reflecting the marginal cost of these services, enabling decision making at the margin by producers and consumers of electricity.

CS Energy provided a report (by Intelligent Energy System ('IES')) to the AEMC in response to the Directions Papers for the 5 minute Settlement amendment proposal and System Security Review. The report highlighted a package of proposals deliberately designed to allow market participants to control frequency through efficient marginal price signals.

In the package there is a real time settlement adjustment for frequency, where deviations in generation, loads, etc that cause changes in system frequency are exposed to the marginal cost of doing so. In the report, on page 33, IES highlighted the relationship between contribution of load, generation and inertia. This is shown in Figure 10 and Figure 14 below. It also includes provision for stepped response from load; however this was not represented in the report.

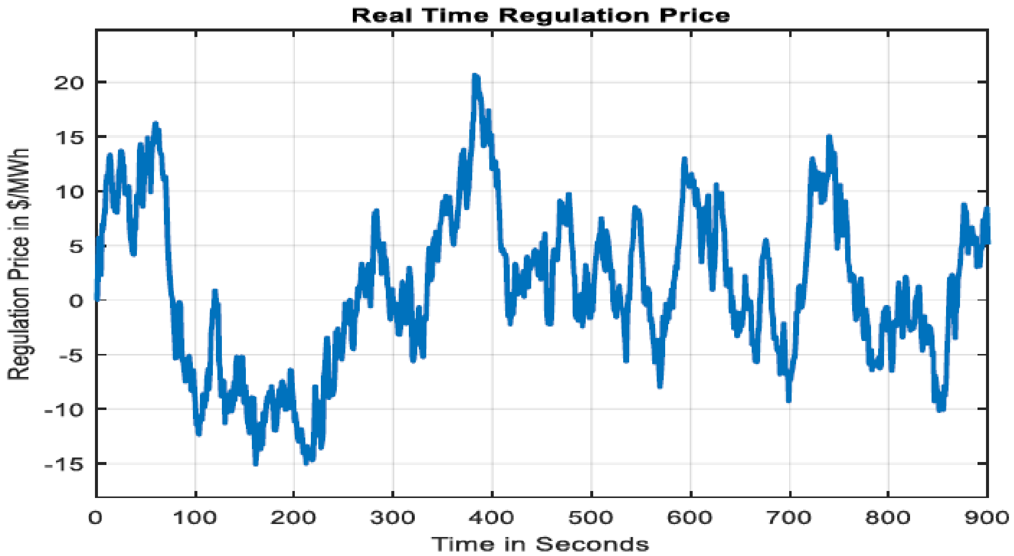
Figure 10: Power Balance in Toy System



Source: Intelligent Energy Systems

The IES report showed the potential for a real time frequency regulation rate (which can be used to adjust the energy price), as shown in Figure 9. This figure presents dummy prices for the cost of regulating frequency within the operating ban, with both positive and negative values as frequency changes.

Figure 9: Real Time Price in Toy System

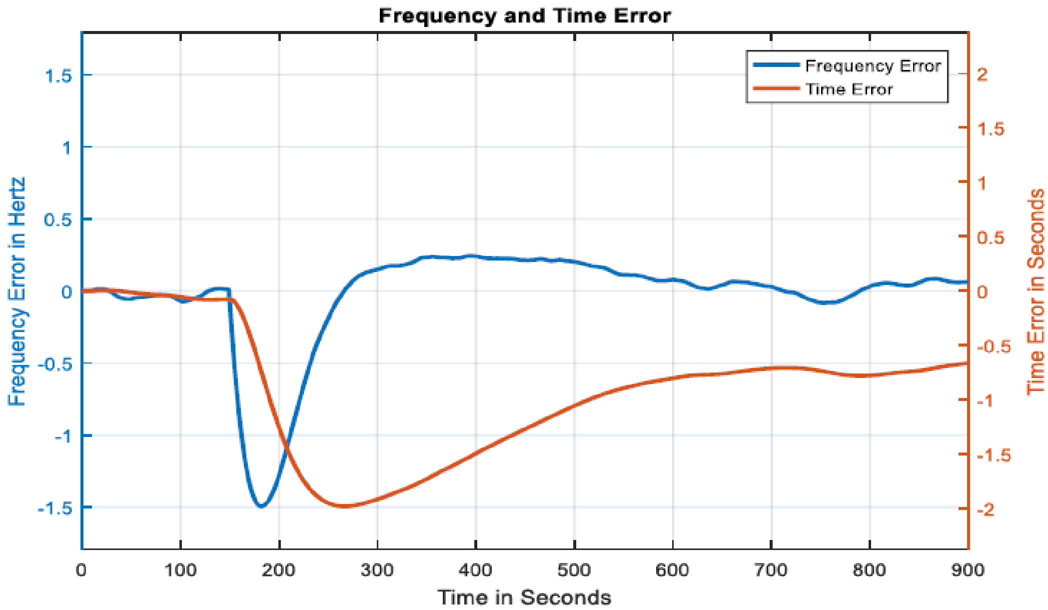


Source: Intelligent Energy Systems

The proposals put forward in the IES report are not solely related to regulating frequency within the normal operating band +/-0.15Hz. IES continue, stating that the proposed calculation would not differentiate between changes in frequency due to small deviations (changes in load) or more significant contingencies, such as the loss of a load, generator or network component. The power balance, frequency and time error are calculated in the same manner.

The following figure12 and 14 show the effect of a 600MW contingency in the toy system.

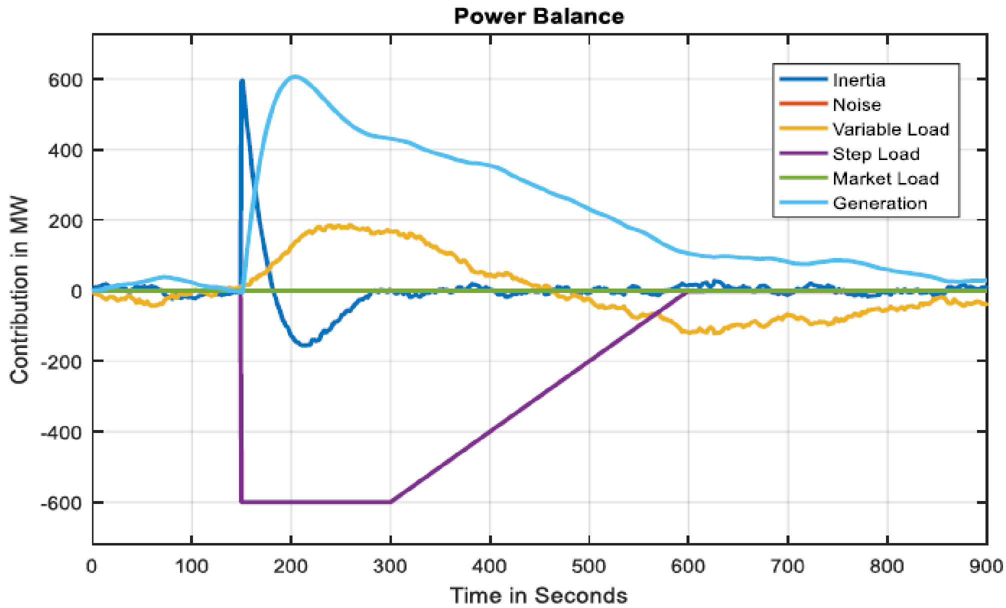
Figure 12: Frequency and Time Error after a Contingency in Toy System



Source: Intelligent Energy Systems

The power balance is presented in the following Figure 14, estimating the split between inertia, load and variable load in responding to the contingency.

Figure 14: Power Balance after a Contingency in Toy System

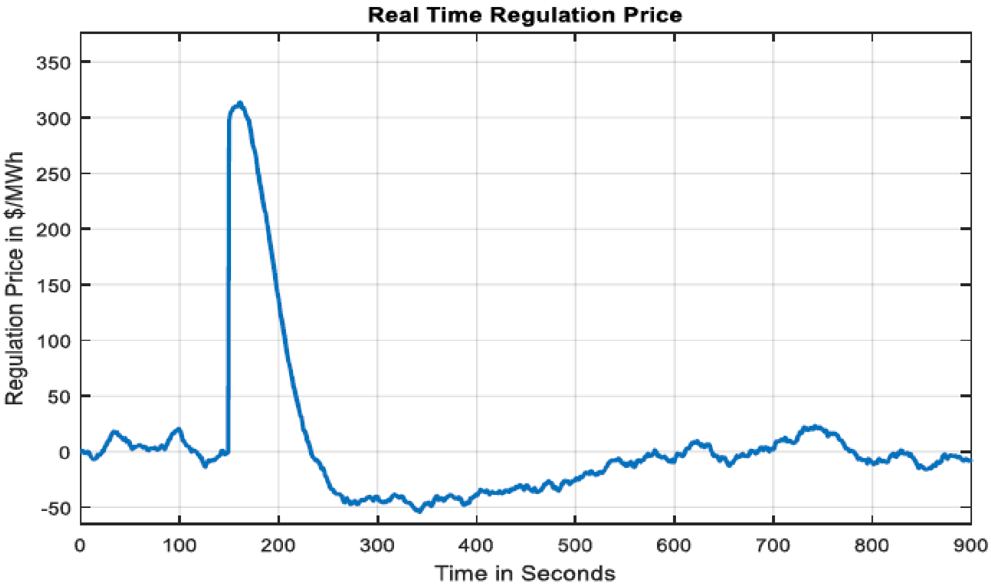


Source: Intelligent Energy Systems

It can be seen after a contingency, in Figure 13, with a significant change in frequency the real time adjustment to price “Real Time Regulation Price” increases. The prices in the system are simply dummy numbers, but it shows a steep climb followed by a more gradual reduction drop. The height of the spike is affected by the quantity of inertia. The duration of the spike is affected by the speed and quantity of the frequency response.

From the consumers’ perspective the cost is the area under the curve. The optimum area will be determined by the competitiveness of the mix of supply from inertia and frequency response from loads, generators, batteries synchronous condensers, etc.

Figure 13: Real Time Price after a Contingency in Toy System



Source: Intelligent Energy Systems

In our opinion, using some of the administrative procedures in the recent Rule changes that set the minimum level of inertia and RoCoF, such as where AEMO identifies inertia shortfalls against a minimum and secure level of inertia, this market led dynamic approach could be applied to the potential frequency islands in the NEM. It will allow market participants to optimise the mix of frequency services.

The IES proposals also include an efficient way to allocate costs to participants that represent the contingency affecting system frequency. By integrating the IES package of improvements, participants can optimise inertia, frequency regulation and frequency restoration services as well as controlling the size of the contingency.

Importantly investors should obtain the responsibility for providing the quantity and mix (inertia vs. quantity of faster response) of service and optimising the level of demand (contingency size, flow, gen, load), rather than some central planner. Commercial discipline will ensure the service is provided as participants respond to the incentives and risks placed upon them. At present this is not the case. AEMO specifies quantities[i] in each of the eight FCAS markets in order to maintain frequency within the operating standards. By excluding inertia, which AEMO takes as given, the mix of services has become sub-optimal as we have too much in the way of slow moving services available, yet too little inertia to slow the RoCoF and make these slower services effective.

On page 25 the RoCoF paper[ii] the Commission discusses technical and economic concepts regarding minimum and secure levels of inertia. The discussion explains how the contingency size; contingent inertia; and speed/quantity of local contingent frequency services (governor control, standing plant, load shedding / tripping) all affect the level of amount of inertia required. The effect of this to describe an optimisation exercise perfectly suited to the process explained above, where frequency is integrated into energy prices and dispatch in the NEM.

The process for determining the secure level of inertia has many similarities to the safety nets the NEM has today: AEMC's Reliability Powers, RERT, ESOO, PASA and LOR, LRC processes which culminate in AEMO's powers of intervention, load shedding and intervention pricing. The minimum and secure level of inertia, explained in the recent RoCoF amendment appears to be a regulatory "safety net" that could quite easily guide market participants or act a precursor for intervention, rather than be an obligation on network monopolies to enter into contracts for the service.

With regards to sub-regional system security issues, the role for network companies or AEMO is to manage these in the same way as the Rules accommodate today with network support agreements. These regulatory rules are necessary given the NEM is a regional pool without local energy prices. Under such circumstances, at the edge of the grid, there may be requirements for the network company to enter into arrangements with existing, or new providers of inertia to manage frequency, fault levels or any other sub-regional security issues. It is our view that such provisions are by exception and not by Rule.

In summary we consider, with the correct incentives placed on market participants, consumers will be better served allowing the market to control frequency and in time, determining the FOS.

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[i] Excluding South Australia which utilises AUFLS in lieu of contingency FCAS
[ii] AEMC 2017, Managing the rate of change of power system frequency, Rule Determination 27 June 2017, Sydney