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Mr John Pierce
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Dear Mr Pierce

Frequency Control Frameworks Review – request for advice

This advice is in response to the AEMC's request delivered by email and dated 13 December 2017. AEMO understands that this advice is intended to inform and support the AEMC's continuing work on the Frequency Control Frameworks Review (FCFR). Specifically, AEMO's advice has been sought regarding various aspects of primary frequency control during normal operation, and also in relation to the changing need and availability of frequency control services in the National Electricity Market (NEM) in the medium to long term.

AEMO is pleased to provide the attached response to the AEMC and has included quantitative assessment where possible given the time constraints of the advice. AEMO is happy to provide further advice to the AEMC on these matters as needed during the review process.

If you have any queries please do not hesitate to contact Matthew Holmes, Principal – Future Energy Systems via matthew.holmes@aemo.com.au or (07) 3347 3039.

Yours sincerely

Cameron Parrotte
Executive Group Manager, Strategy and Innovation

Attachment 1: AEMO response to request for advice

Assessment of primary frequency control under normal operation

The AEMC requested AEMO's advice on the nature of primary frequency control to support its work on the Frequency Control Frameworks Review (FCFR). The AEMC asked AEMO to provide advice on the following matters, and any others AEMO considered relevant:

- The operational benefits of primary response during normal operation, independent of headroom capacity.
- Geographical distribution of service.
- Frequency responsiveness capabilities of existing fleet.
- Headroom considerations.
- Interaction of primary and secondary control in relation to controlling frequency.

The purpose of the FCFR is to establish whether the NEM's current frequency control frameworks properly recognise the essential elements of good frequency control. A particular aspect of this is the lack of any formal mechanism for recognising and managing the role of primary frequency control within the Normal Operating Frequency Band (NOFB), or as stated here 'under normal operation'. Evidence to date[1] suggests this has been a key contributor to a continually deteriorating quality of frequency control over the past decade or so as formally unrecognised frequency response has been progressively withdrawn from the NOFB. This frequency response is not currently recognised by the regulatory or market frameworks. Continuation of this situation is likely to result in worsening frequency control as primary control continues to be withdrawn over time. Without primary control continuously active under normal operating conditions, it is unlikely that AEMO will be able to meet the obligations of the Frequency Operating Standard (FOS). Therefore it is crucial that the FCFR establishes mechanisms to ensure primary frequency control is available within the NOFB.

AEMO has approached this advice by first considering the nature of primary and secondary control, and then examining how they interact to deliver an overall level of frequency control to the grid. Following this, AEMO has drawn on modelling from the 2016 National Transmission Network Development Plan (NTNDP) and other work from AEMO's Future Energy Systems program to examine the medium to long term need for frequency control and the availability of sources which may provide it.

AEMO expects that this advice will assist the AEMC in its evaluation of approaches for formally recognising primary frequency control during normal operation as part of the suite of frequency control tools used in the NEM, and to support the other work streams of the FCFR, particularly in examining the effectiveness and appropriateness of the existing frequency control ancillary services (FCAS) markets, and the potential role of distributed energy resources (DER) in frequency control services.

In AEMO's view, due to their interconnectedness, the complete suite of system services required to achieve power system security and reliability need to be considered when considering changes in any one service such as frequency control. As such, AEMO

[1] Such as the DIgSILENT report to AEMO 'Frequency Control Performance in the NEM under Normal Operating Conditions' at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Working_Groups/Other_Meetings/ASTAG/371100-ETR1-Version-30-20170919-AEMO-Review-of-Frequency-Control.pdf

considers that a more encompassing and holistic view of the needs of the future framework should be taken, and looks forward to working with the AEMC and other ESB colleagues and industry stakeholders to achieve the opportunities and resolve the challenges of the energy system transformational change.

Defining primary and secondary frequency control

The terms primary and secondary frequency control are used across the power system industry as a common language to describe the kinds of frequency control services necessary for the successful operation of any power grid. Individual grids have different names for the services within each category, and aggregate and/or disaggregate them in various ways. However, the fundamental services are the same. AEMO considers it useful to define and describe these terms here, as they are used extensively throughout this advice and the FCFR itself.

Primary frequency control (PFC) is a frequency response that is:

- Dependent on locally-measured frequency, so not subject to centralised control, communications delays and time synchronisation issues to any significant degree
- Fast-acting. Action typically starts nearly immediately and becomes significant in a handful of seconds. However, it may not be sustained more than a minute or two.
- Continuous and proportional. That is, it acts continually in a closed-loop manner, adjusting generator output as appropriate to arrest and stabilise (but generally not restore) frequency. This is generally done through proportional control, which adjusts generator output in a manner in proportion to the measured frequency deviation. This form of control is often referred to as ‘droop’ control.

The NEM’s 6-second and 60-second contingency services could be considered forms of primary control, but critically, they activate only once frequency has left the NOFB. This means these services do not contribute to ‘normal’ frequency control. Categorising these services as primary control is debatable, since under normal circumstances (i.e. while operating within the NOFB) there is no formally recognised and delivered role of primary frequency control in the NEM and thus nothing to operate in conjunction with secondary control. In practice, various generators still do provide a primary frequency response within the NOFB, but this is a side-effect of how their control systems happen to be designed, rather than by anything dictated by the NEM’s rules and procedures.

Secondary frequency control (SFC) is a frequency response that is:

- Dependent on a single frequency reference (often centralised) rather than on individual locally-sensed frequency
- Designed to take over cleanly from primary control in order to let sources providing primary control to return to their normal set-points (and thus be ready for further primary response as required).
- Co-ordinated by the system operator (e.g. via AGC – Automatic Generation Control) or by a designated ‘frequency keeper’ (e.g. a particular power station)
- Slower-acting and sustained for a significant period of time. Significant action might be expected from about 1 minute (i.e. relieving diminishing primary control) and would be expected to be sustained for 5 minutes and potentially indefinitely. The timing of this action is more to do with the method of control than the response time of units. Discrete but regularly adjusted, in that the amount of response desired is expected to

be adjusted frequently (e.g. every 4 seconds in the case of the mainland NEM) by the system operator or frequency keeper.

The NEM's *regulation services* are is the secondary control mechanism which is tasked with attempting to keep the frequency within the NOFB 99% of the time, although these services continue to act outside of the NOFB also.

Proportional versus switched control

As described in the preceding section, primary frequency control is generally continuous and proportional. But increasingly, contingency services in the NEM are being offered in the form of switched control. There is an important distinction to be made between switched and proportional/continuous frequency control services. Currently the FCAS framework does not discriminate between these two quite different forms of control; they are considered equal and interchangeable. However, this is not satisfactory for operational application, as based on price alone, market dispatch could select 100% switched control. Because of the nature of switched control, as described below, this would not provide satisfactory frequency control performance. As a real example of this distinction, AEMO is preparing NEMDE constraints to manage the proportion of switched services procured in Tasmania, which as a small separate AC area, is particularly susceptible to frequency disturbances.

Switched frequency control services act by switching in or out load or generation in response to measured frequency crossing a pre-determined trigger point. The response is then generally maintained for a pre-determined time. Switched services are offered by both loads and generators, and more recently, by aggregators. In the case of a generator, it will have a pre-determined offset (in MW) to its dispatch, and if the trigger frequency is crossed, the offset will be applied to the generator's output. In the case of loads (or aggregators), a particular load or set of loads will be switched off if the trigger frequency is crossed. Switched services are only allowed in the FCAS contingency markets[2]. AEMO maintains a list of the agreed trigger points and quantities, but the markets are unaware of this, and select providers based on price only.

Switched services may be considered open-loop control, compared with the closed-loop (feedback) control offered by a proportional response. Therefore switched services do not exactly align with either primary or secondary control. Switched services can be configured to mimic proportional control to some extent by distributing switched service over a range of frequency triggers and varying duration, but they are not truly continuous. The relative amounts of switched and proportional services must be carefully co-ordinated for optimal frequency control. Switched services are probably better suited to comparatively infrequent but urgent situations rather than during normal operating conditions. In such a case, the situation is critical, so fine-tuned service delivery is much less of a priority. For example, if the frequency has gone below the NOFB, a quick effective response is required to quickly arrest any further fall in frequency before load shedding and protection schemes are triggered. This occasional usage also suits the fact that switched services are often delivered by loads (that is, by switching off part or all of a load); it would be impractical for most loads to be switching on and off frequently. Furthermore, as loads are often variable, the quantity of response at the time of the trigger is not necessarily precise.

[2] The regulation service requires that providers have the ability to respond continually to AEMO's AGC commands, and switched services cannot meet this requirement.

Active Power Control

AEMO notes that some stakeholders have expressed that the term primary frequency control is confusing or at least unnecessary and that the term 'active power control' should be used instead. AEMO has used the term 'active power control' in the generation technical standards work being undertaken currently[3]. However, both primary and secondary frequency control services fall under the *umbrella* term of active power control, which is typically used to refer to the control of active power output from inverter-based sources[4]. Indeed many other services may also be labelled forms of active power control (e.g. ramp-rate control, synthetic inertia, etc.). Active power control is simply the control of *active* power output (as opposed to *reactive* power output) of a generator in response to a control scheme, rather than active power output being solely dependent on the fuel source availability, such as the amount of sunlight falling on a set of PV panels. The term is typically used in relation to inverter-based generation, but could be more generally applied to synchronous generators too. AEMO therefore considers it important to retain and understand the primary and secondary terms when it is necessary to distinguish between them.

Distribution of primary frequency control

Managing the distribution of FCAS throughout the NEM is not considered by the current FCAS framework. Rather, the ancillary services market is designed to source FCAS globally wherever physically possible and share the cheapest services across regions. This design cannot be expected to deliver the optimum level of frequency control. Frequency response that is evenly distributed throughout the power system offers a range of additional benefits, but cannot be economically implemented within the existing market design. Enacting permanent or semi-permanent localised FCAS requirements under the current framework would reduce competition in the FCAS markets substantially, naturally leading to substantially higher prices.

As a locally sensed, fast-acting and continuous method of control, it is reasonable to expect primary frequency control to be more effective when delivered locally. Primary frequency control service acting close to the cause of a frequency deviation is likely to be most effective, and reduces the likelihood of oscillation in the power system that can result from remote frequency responses. This is especially important in longer and more weakly meshed systems such as the NEM.

Distributing primary frequency control broadly across the network would also create a more robust system. As an example, consider the situation where part of the network is unexpectedly islanded. If units in the island are providing primary frequency control, the island has a much better chance of survival as units would quickly react to attempt to stabilise frequency before major consequences result. While AEMO would act to source frequency control services (in the form of FCAS 6-second and 60-second contingency services) from specific areas of the network where a separation is considered credible, broadly distributed, continually activated primary frequency control may offer considerable resilience for non-credible or other unanticipated events.

[3] http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards

[4] For example by CIGRE as illustrated here: http://c4.cigre.org/WG-Area/JWG-A1-C4.52-Wind-generators-and-frequency-active-power-control-of-power-systems

Since secondary frequency control is a slower acting service and is centrally controlled, during normal system conditions it is less important for it to be broadly distributed. This is especially the case if primary frequency control is already broadly distributed. Power flows resulting from secondary control should be far less volatile and more predictable than those resulting from primary control. However there are still advantages of dispersed secondary services such as improved interconnector control[5]. It is also worth noting that increasing concentration of solar generation in a region is likely to increase the volatility of the load to be met by other generation, which would place greater importance on some localised secondary (as well as primary) control.

Interaction of primary and secondary frequency control under normal operating conditions

From the definitions and descriptions of primary and secondary frequency control, it can be seen they are quite different, especially in terms of their control paradigm, response time, sustain time and controlling range (i.e. dead-band settings etc.), and are not broadly interchangeable. However, it is reasonable to consider whether perhaps a minor shortfall in one service may be made up by procuring more of the other. AEMO has analysed this by drawing on the fundamentals of how primary and secondary control are specified.

All following analysis is based on the assumption that primary frequency control is delivered in a continuous manner without significant dead-bands[6]. This is not the case at present in the NEM, however, where primary control dead-bands are only required to be no wider than the NOFB itself (as per the requirements of 6 and 60 second contingency FCAS), and units are generally not required to be frequency responsive at all unless allocated to FCAS duty by the market. In practice, at the moment dead-bands are configured differently across the generation fleet without particular co-ordination (with the trend being to widen them to the edges of the NOFB) and may indeed vary for a given generating system depending on its mode of operation. For the purposes of this advice, AEMO's analysis sets this aside in order to study how a potential primary control response within the NOFB would interact with the existing secondary control mechanisms.

It is easier to begin this analysis by examining secondary control. For normal system operation, in the absence of contingency events, the amount of secondary control (in terms of MW that need to be injected or removed) required to correct a given frequency deviation is called the Area Control Error (ACE). ACE is determined by the following:

$ACE = 10 * \beta * (AF - SF - FO)$

Where:

- β is the system frequency bias (in MW/0.1Hz)
- AF is the actual/measured frequency
- SF is the scheduled/target frequency (50Hz in the NEM)

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[5] Localised frequency response means interconnectors will remain closer to the flows scheduled by market dispatch, which could allow a higher proportion of the interconnector capability to be accessed (by relaxing margins in constraints).

[6] Dead-bands could still exist but would be small and well within the NOFB. For example, AEMO would regard a dead-band of say +/- 25 MHz would be considered to be not significant blocking primary control action within the NOFB (+/-150 MHz).

- FO is a frequency offset, only used if there is a desire to bias the nominal frequency (i.e. to deliberately run the grid fast/slow for time error correction or other purposes).

Therefore it may be seen that the amount of secondary control needed to deal with a given frequency deviation is effectively set by β, the system's 'frequency bias'. The frequency bias is made up of load relief and the effect of primary control action (i.e. the expected primary frequency control based on historical measurement). Note that in the NEM, the expected primary control action within the NOFB could theoretically decline to zero, since it is currently unrecognised and thus not required to be supplied. However in practice many generators continue to be frequency responsive within the NOFB, mostly as a result of the design of their governor control systems. Without change to the frequency control frameworks though, there is no reason to expect this situation to persist as generators either revise their control systems, or in some cases, are retired from service.

Notwithstanding issues with the current frequency control framework around primary control in the NOFB, it may be seen that using a system frequency bias of -280 MW/0.1Hz (AEMO's current value for the mainland NEM) for a frequency of 49.95 Hz, ACE would be (10*-280*(50-49.95) = 140 MW. That is, an injection of approximately 140 MW would be required to lift the frequency 0.05 Hz back to 50 Hz. Conversely, generation would need to be reduced by 140 MW to correct a frequency of 50.05 Hz back to 50 Hz. It is noted how different this is to the amount of regulation FCAS currently acquired, which is 130 MW of raise and 120 MW of lower regulation to cover deviations of within the NOFB (that is, +-0.15 Hz).

In real systems, the system frequency bias is something that is always determined empirically, rather than by theory, though 'rules of thumb' do exist. This is because load relief and primary control action vary according to many factors, including time of day, generation dispatch patterns and weather, and in a large complex grid are impossible to determine except by observation. However, the theory is useful in showing how primary frequency control and system frequency bias are linked.

Load relief is the manner in which the system load changes in proportion to the frequency. A load relief of 1.5% (the value typically used in mainland NEM) means that a 1% change in frequency is expected to result in a 1.5% change in demand (in the same direction). Therefore, for a system demand of 20,000 MW, if frequency declined to 49.95 Hz, demand would decline by 30 MW, or expressed in the terms of frequency bias, 60 MW/0.1Hz.

Primary frequency control is determined by the 'droop' characteristic of the generation fleet. Droop defines the proportionality of a generator's primary response to a change in frequency. A 5% droop setting means a generator will move to full output for a 5% decrease in frequency from nominal (and go to minimum load in the event of a 5% increase in frequency from nominal). In practice, droop can vary widely between generators, and even for a given generator it is not strictly linear and indeed changes depending on how the generator is configured at a given point in time including how dead-bands may be configured. Nonetheless, assuming say 3,000 MW of frequency responsive generation (15% of the assumed 20,000 MW demand) with an average equivalent fleet droop of 3% (and no significant dead-band[7]), the primary control frequency bias may be calculated as 3,000 MW / (50 Hz * 3%) which is 2,000 MW/Hz or 200 MW/0.1Hz.

Summing the load relief and primary control frequency biases gives the total system frequency bias which in this example is 60 + 200 = 260 MW/0.1Hz. This needs to be multiplied by -1 for use in calculating ACE, and thus becomes -260 MW/0.1Hz. Therefore in

[7] A dead-band refers to a frequency band within which the unit will not be frequency responsive.

this example, factoring in the assumed load relief and primary frequency response, when the system frequency changes by 0.1 Hz, the ACE is 260 MW. In other words, a 0.1Hz change in frequency represents a supply-demand mismatch of 260 MW. Therefore it can be seen that to correct this frequency back to nominal, it would take a 260 MW increase (or decrease) in generation. The ACE is what the NEM's secondary control mechanism - AGC (Automatic Generation Control) – seeks to correct by scheduling changes in generation output. In effect, in this simplistic example, the AGC system will need to add (or remove) 260 MW of generation to correct the frequency back to nominal, as this is what has been temporarily supplied by the combination of load relief and primary control[8].

If there is only half as much primary response (i.e. only 1,500 MW providing 3% droop), then the primary control frequency bias is also half; that is 100 MW/0.1Hz. Note that the same primary control frequency bias (i.e. 100MW/0.1Hz) would be obtained from 3,000 MW of primary control with an average droop of 6% (rather than 3%). Assuming the same demand, the load relief frequency bias would be unchanged, so the system frequency bias comes to 160 MW/0.1Hz. In this case, a 0.1 Hz change in frequency is equivalent to a 160 MW supply-demand imbalance. To correct the frequency back to nominal, only a 160 MW change in generation would be required. However, since this is symmetrical, it also means that in the first example, a generator trip or forecast error of 260 MW would only move the frequency by 0.1 Hz[9]. In the second example, a trip of just 160 MW would move the frequency by the same 0.1 Hz. A mismatch of 260 MW would see the system frequency decline by 0.163 Hz, which is a 60% larger deviation. That is, as the primary control response reduces, frequency will move further for the same underlying level of supply-demand mismatch. However, the same amount of secondary control will be required, as the purpose of secondary control is to correct the mismatch and allow units providing primary control to return to their targets (set-points).

This analysis leads to a key point, which is that to a first approximation, the primary control requirement (in MW/Hz) for a given system can be established based on how far frequency is allowed to deviate for a given underlying MW mismatch. The secondary control requirement is set by the size of that mismatch itself (in MW).

In reality, as discussed later, this is not so straightforward, as both services are operating continuously and in parallel.

Following through the equations for system frequency bias shows that that doubling the amount of primary control reduces the size of the entire frequency deviation by about 40%. An illustration of this effect is shown in the following (hypothetical) figure:

[8] Commercially available AGC software includes features designed to help improve system stability such as by adding an integral component of ACE and to calibrate the AGC response to the severity of the frequency deviation through variable gains.
[9] In steady-state terms.

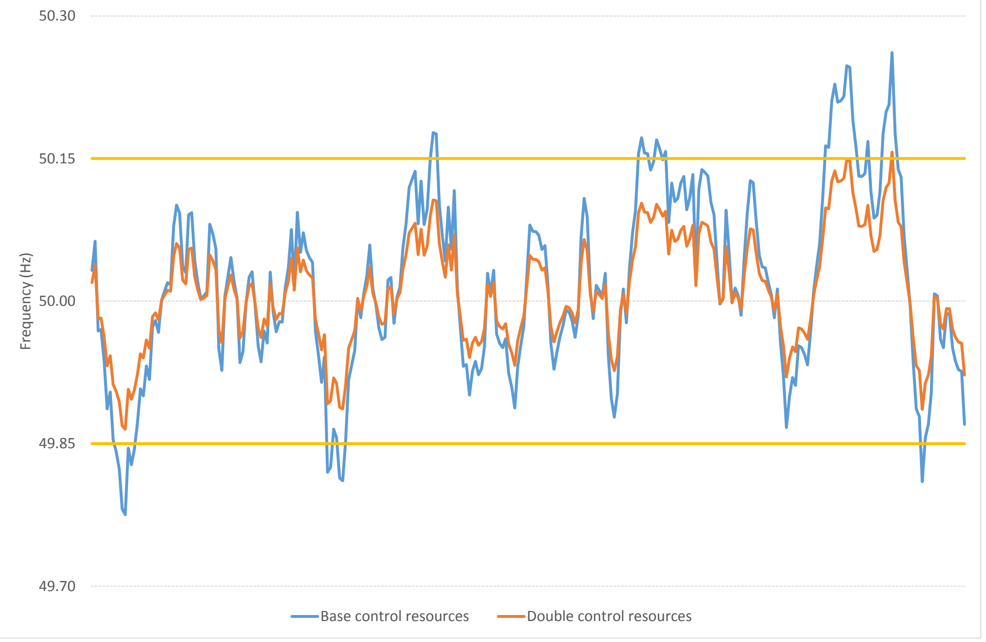


Figure 1 - Illustration of effect of doubling primary control resources

The example assumes continuous proportional primary control. This example ignores the complication of the handover between primary and secondary control. However, it illustrates the point; that doubling the primary frequency control resources means frequency containment improves by about 40%. In this hypothetical example, the NOFB is exceeded regularly in the case of the Base control resources, but doubling the control resources nearly eliminates any breach of the NOFB. This is an important consideration affecting how the obligations of the FOS may be best met.

Application to the NEM and the FOS

The theory and simple examples given thus suggest that primary and secondary control cannot be 'traded' against each other. This means that it is not feasible to create a function by which to co-optimise the requirements for primary and secondary control. However, in practice this may be less absolute. This is because of factors such as:

- The average quality (i.e. the speed and accuracy of delivery) of primary and secondary frequency control could differ significantly.
- Dead-band settings affect this significantly, especially if they represent a large proportion of the NOFB[10].
- Proportional primary control is always used if available; secondary control is only used as scheduled by the control system (AGC).
- Timing issues, including the timing of service delivery and the economic dispatch cycle, may impact the behaviour of the services.
- The FOS in its current form specifies that in normal operating conditions, frequency should remain within the NOFB for 99% of the time. Importantly, frequency does not need to return exactly to the nominal 50Hz.

[10] Where dead-bands prevent primary response, only secondary control is active.

The effect of these factors on the interaction of primary and secondary control are difficult to model in a meaningful manner. However, within the timeframes available for this advice, AEMO has attempted to undertake some analysis of how these factors may impact the interaction of primary and secondary frequency control. This should be treated as indicative information only; further detailed analysis and ultimately only experience in applying this in the real power system would provide sufficient data for a reliable assessment of service adequacy.

The impact of dead-bands on frequency control

The current FCAS frameworks do not require that any primary control to be delivered within the NOFB. This is because the only services offering this form of control, contingency FCAS, specify that the service need only be delivered from the edge of the NOFB, and can be terminated when frequency returns to the NOFB. This means that currently, primary control within the NOFB is neither regulated nor market driven, with generators able to change their frequency response mode and settings into or out of the NOFB[11].

The DIgSILENT work and AEMO's recent generator survey similarly concluded that there has been a progressive move towards reducing frequency responsiveness within the NOFB, by way of widening dead-bands in primary control systems, or by damping out primary control in the NOFB by way of supplementary control systems. There are several drivers which, together, have led to this situation. However the key problem is that the current FCAS framework does not recognise the role of primary response within the NOFB in providing good frequency control and thus places no obligations on generators to provide such a response, or even to inform AEMO when changes to the settings are made.

The notable effect of reducing primary control within the NOFB, as the theory in this advice has discussed, is that for any given supply-demand imbalance, the size and duration of the frequency deviation increases. This makes a given imbalance more likely to result in frequency moving outside the NOFB, and therefore increasing the risk of breaching the FOS.

Since primary control in the NOFB is not recognized or required under the current FCAS framework, it is worthwhile to consider what would happen if all primary frequency control was removed from the NOFB. This would mean that only load relief and secondary control, would be available to control frequency within the NOFB. Consider the equations and examples given earlier for a hypothetical 20,000 MW system demand and 1.5% load relief. With ~3,000 MW of primary control in the NOFB operating with a 3% droop, a supply-demand imbalance of approximately 400 MW is required to push frequency to the edge of the NOFB. But without any primary control, it only takes an imbalance of approximately 90 MW. While these numbers are unlikely to be directly translatable to the NEM, assuming they are at least roughly comparable demonstrates that withdrawing all primary control from the NOFB could result in the frequency straying outside of the NOFB on a highly regular basis, since imbalances of tens of MWs or more are routine in the NEM[12]. While the contingency FCAS services would attempt to contain this, the NEM's overall frequency performance would be extremely poor. With the system frequency so sensitive to imbalance, it is possible that contingency services could not catch frequency quickly enough, which would mean significant load shedding would be possible for routine imbalances of supply and demand.

[11] Note that generators are required to seek AEMO's approval for changes to frequency response under rule 4.9 and clause 5.3.9 of the NER. However, AEMO must approve such a request where it meets the automatic access standard in Schedule 5.2.5.11.

[12] Consider that 90 MW out of 20,000 MW is an error of less than half a percent.

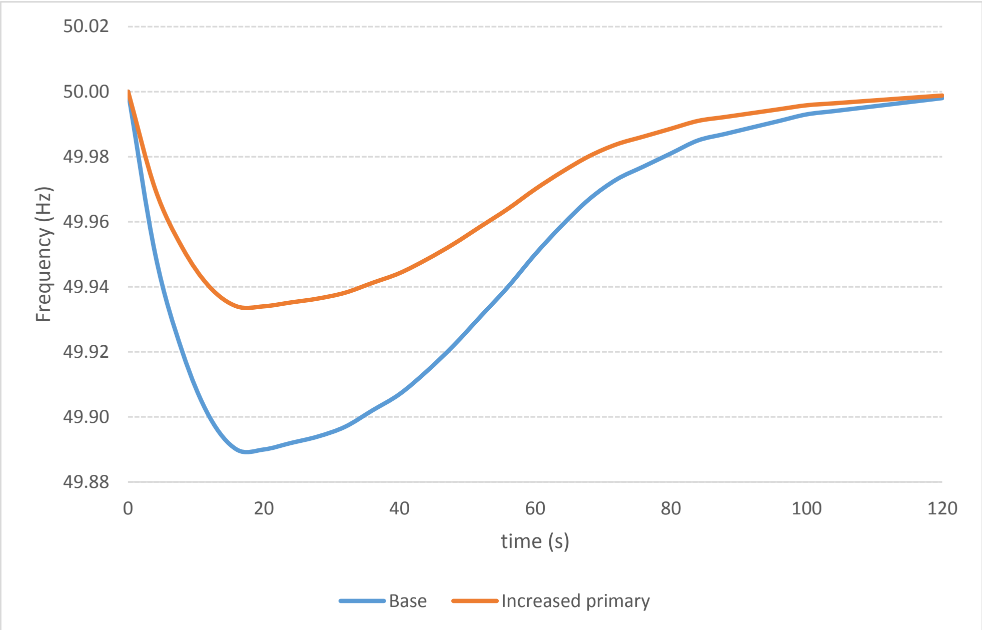
The declining performance of frequency control has been quite apparent in the NEM. In the current environment of configurable dead-bands and frequency responsiveness, the amount of primary frequency control available within the NOFB at any point in time is not able to be reliably predicted or managed. This means that AEMO cannot rely on any particular frequency characteristic for a given supply-demand imbalance, and cannot reliably set AGC parameters such as the system frequency bias. Therefore optimal frequency performance may not be achievable without increased certainty over the variables affecting frequency bias.

Taking this into account, it is apparent that to improve frequency control by a significant margin, it is essential that primary control within the NOFB be formally recognised, specified and procured by AEMO.

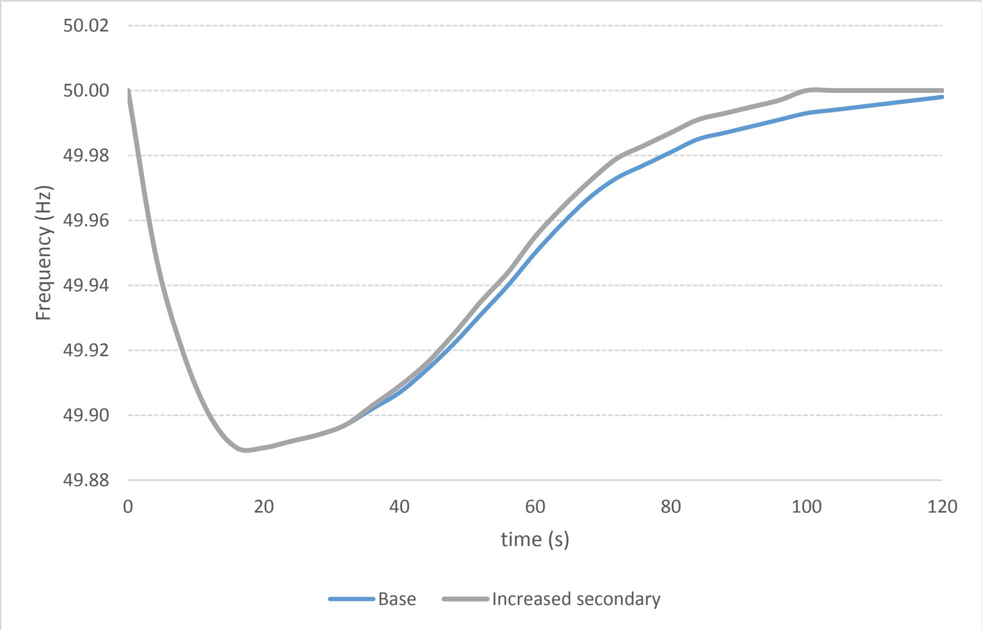
The impact of additional control resources

The relative effect of increasing different frequency response types illustrates how the relative benefits of each form of control can lead to better overall control of frequency. This is demonstrated by way of separately assessing the impact of adding a significant amount of primary and secondary control.

Adding a significant amount of additional proportional primary control (with no significant dead-band) without any corresponding increase in secondary control would mean frequency deviations (especially within the NOFB) are arrested faster and the frequency deviation itself would be smaller. The total restoration time (that is, back to 50Hz) will likely be similar as this is dictated by the timing of secondary control. This effect is illustrated below:



Adding a significant amount of additional secondary control (without additional primary control) would increase the total resource the secondary controller (AGC) has to work with. Effectively, for higher ACE values, the secondary controller would have more control action to draw upon. This means restoration of frequency would occur earlier. It would also improve restoration time for smaller events somewhat, because there would likely be more providers, meaning the ramping achieved by them in aggregate is likely to be higher. This effect is illustrated below:



While these examples are only illustrative and not to scale, it can be seen that adding additional primary control (rather than secondary) achieves a much greater difference in area from the base level. This is chiefly because primary control is continuously responding to frequency deviations. Additional primary control makes this response more effective. Secondary control is only used when necessary, and only by the amount dictated by the secondary control mechanism (e.g. AGC). Note that in these examples it is assumed that there is an adequate amount of both forms of control to begin with. That is, and adequate amount of secondary control is required to take over from primary control to provide the final correction of frequency to 50Hz and also to enable the providers of primary control to return to their normal set-points.

This discussion indicates that additional primary control will be significantly more effective than additional secondary control both to contain the maximum frequency deviation and to reduce the integral frequency error (i.e. the area under the curve). This suggests that additional primary control acting within the NOFB (with tight dead-bands) would be a highly efficient means of meeting the FOS, compared with additional secondary control. This assumes, of course, that there is adequate secondary control to correct any underlying supply-demand mismatch; if not, additional secondary control will be required and attempting to cover this shortfall with primary control would be ineffective.

Control implications of the FOS

The way in which the existing FOS requirements are formulated can impede optimal frequency control outcomes. The FOS states that frequency should be maintained within the NOFB 99% of the time. Therefore AEMO seeks to acquire just enough control resources to achieve this; that is, enough resources to restore frequency to the NOFB, but not necessarily enough to return frequency to 50 Hz. The only control resources that can currently be formally procured are secondary control resources. Since the secondary control requirement is broadly set by the underlying MW mismatch, this means AEMO is encouraged by the FOS to acquire less than the amount actually necessary to fully correct the frequency to 50 Hz as a result of ‘normal’ frequency disturbances. Thus the FOS does not drive the acquisition of the optimal quantity of control resources. In this regard the FOS does not reflect AEMO's interpretation of good practice in frequency control. Furthermore, it is acknowledged that it has traditionally been assumed that a certain amount of primary frequency control (with no real dead-band) would always be available within the NOFB. While AEMO could procure more secondary control services than is necessary to just meet the FOS, it is assumed that the FOS sets out the efficient level of frequency performance and thus service procurement, and that exceeding this level results in unwarranted costs to consumers (i.e. it arguably would conflict with the NEO). The implications of this should be further considered and addressed by the FCFR and Stage 2 of the FOS Review.

Headroom considerations

Up to this point, the discussion of primary and secondary control has disregarded the matter of headroom. Headroom is quite a separate consideration to frequency responsiveness itself. That is, while a generator could technically be frequency responsive, it can only change its output if it has the physical 'headroom' to do so. Headroom refers to the amount that a generator is able to move up or down; in this case in response to a change in frequency. A nominal 100 MW generator with a 30 MW minimum load operating at a set-point of 60 MW might have 30 MW of downwards headroom and 40 MW of upwards headroom. Headroom can be further limited by a unit's minimum and maximum load in current conditions. For example, a steam turbine fed by coal crushing mills will have headroom only to the end of any partially utilised mills. Bringing a new mill online would potentially allow a higher headroom but is only done when the unit is expected to operate at those higher levels. Similarly, downwards headroom could be limited due to "rough running ranges" or other factors.

The calculations in the preceding sections analysing frequency bias and response do not consider this issue of headroom availability. These calculations assume that there will be adequate headroom to provide the assumed droop characteristic. In practice, this is not necessarily the case. There is almost always some level of natural headroom in the system due to the economic dispatch of units (although peak or minimum load times may see little headroom); that is, it is likely at any given point that economic dispatch results in there being a reasonable amount of headroom distributed across the fleet. However, in the future, as non-synchronous generation continues to displace thermal generation, the 'natural' headroom might be expected to decline, as these generators tend to always operate at their maximum potential output. Storage technologies may tend to maintain significant headroom, but this will only be accessible if the incentives and controls are set up appropriately. Regardless, it must be recognised that any natural headroom is certainly not guaranteed. One of the main objectives of the current FCAS markets is to ensure a minimum amount of headroom is explicitly acquired for system security purposes since it cannot otherwise be relied upon.

If a particular minimum level of primary control is desired to be available within the NOFB at all times, it will also be necessary to explicitly acquire this in some manner. As discussed, this will become increasingly important as the generation mix moves more towards non-synchronous variable generation. AEMO's advice on the 'Outlook for frequency control in the NEM' below explores this in a more quantitative manner.

Medium to long term outlook for frequency control in the NEM

The AEMC requested that AEMO provide advice on the possible future need and supply of frequency control services to see how they might be expected to change. This is an important consideration for any proposed changes to the current framework, as the framework in place at any given time influences investment decisions spanning decades.

Given that the FCAS frameworks have been in place in more or less their current form for approximately 16 years, AEMO has considered a similar time horizon. To forecast how the system could develop over this timeframe in terms of frequency control capability, AEMO has drawn on modelling conducted in the 2016 NTNDP[13]. While much has changed since this time, AEMO regards that this modelling still reasonably demonstrates the possible future in terms of the availability of existing technologies. To demonstrate the likely availability of resources that *currently* offer substantial frequency responsiveness, AEMO has estimated the number of units of different types that might be expected to be online during the course of a typical day. Time of day analysis is shown because this is where the largest variation was observed; seasonal differences for example were found to be very small.

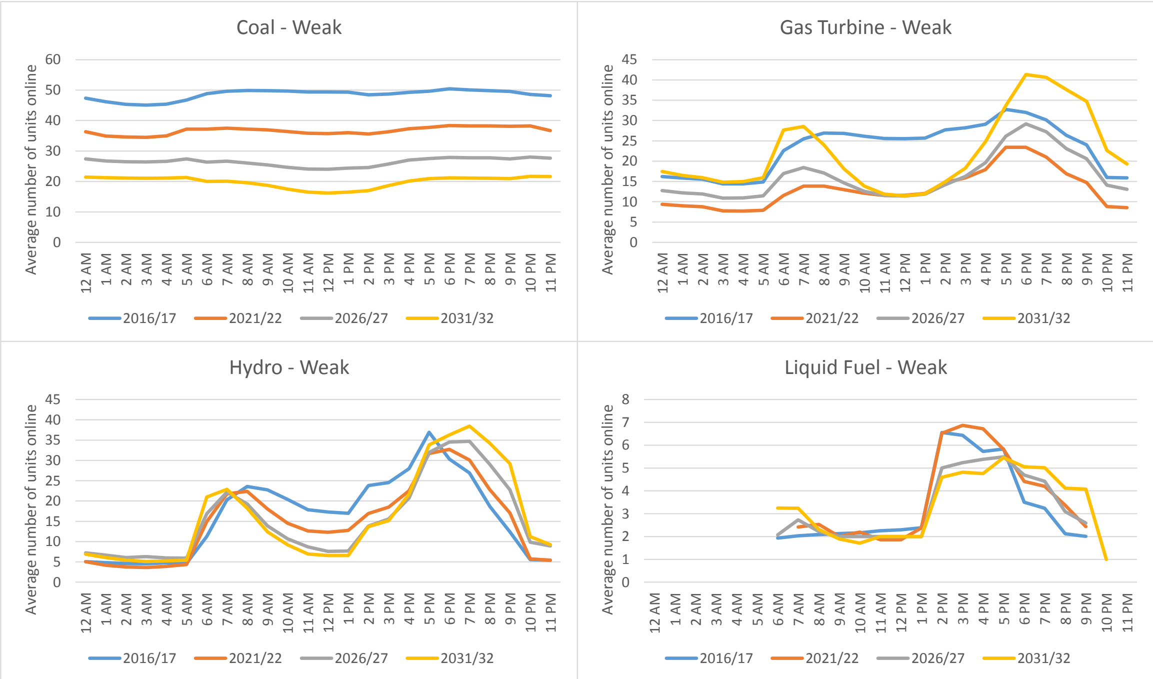


Figure 2 – Estimated number of units online by time of day (2016 NTNDP weak scenario)

Note that these figures omit non-synchronous generation. Unit numbers for non-synchronous generators do not represent a good proxy for the likely availability of frequency response. Secondly, these kinds of resources currently provide only limited amounts of FCAS, although this could change given suitable incentives. Some FCAS capability from non-traditional sources has been demonstrated by Hornsdale Wind Farm 2, the Hornsdale battery, and various demand-side providers. These figures also omit Tasmania as it is not synchronously connected to the mainland NEM; Basslink's behaviour represents Tasmania's frequency responsiveness as seen by the mainland NEM, rather than the units within Tasmania.

What is shown by these figures is that over the course of the next ~15 years, it is reasonable to expect that there may be a dramatic drop in the number of large synchronous units online

[13] National Transmission Network Development Plan. The 'weak' scenario is presented here, being the scenario showing the most significant change from business as usual in terms of the availability of frequency responsiveness

at any point in time. These synchronous units are currently the key providers of FCAS as they:

- Often maintain significant headroom as normal operating practice.
- Possess the physical ability and necessary infrastructure to meet current FCAS requirements.
- Tend to be high capacity, and thus can provide significant volume to FCAS markets.

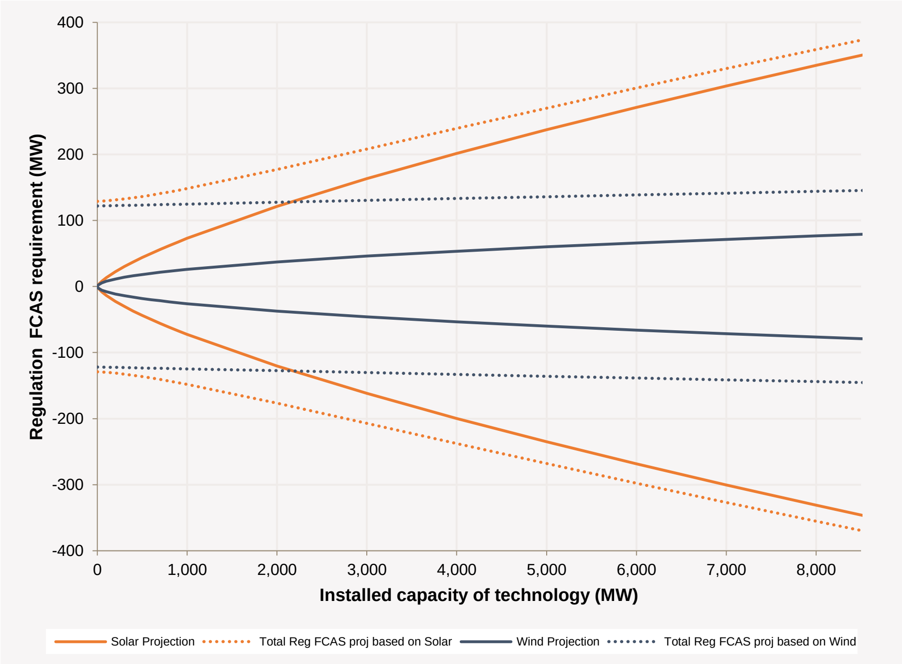
In particular, the number of coal units that might be expected to be online during the middle of the day may halve over the course of the next ~15 years, reducing from current levels of ~50 to just ~25. At the same time, the number of gas units online may also halve.

Since hydro and liquid fuel units are not forecast to increase operation during these times, it is reasonable to assume that this means that the available frequency response from synchronous generators may be only half current levels.

Simultaneously, the demand for frequency response will likely increase. This is because an increasing proportion of the generation mix during the middle of the day is expected to be supplied by solar generation (and to a lesser degree, wind generation). Solar generation can be highly variable - more so than other types of generation - as it responds very quickly to intermittent clouding. Analysis of the existing utility-scale solar farms in the NEM shows that changes in output of >50% of rated capacity may be expected to occur within 4 seconds[14]. Even with advanced forecasting techniques, during the middle of the day, it is reasonable to expect that supply from solar generation may drive more variability in the supply-demand balance. Movement such as this within dispatch periods would be dealt with using FCAS. Depending on the concentration of solar in particular regions, and the possible increase in supply-demand mismatch volatility, it is possible a mechanism such as tie-line control between regions may be necessary in order to retain satisfactory interconnector control. This would dictate localised sourcing of primary and secondary control, at least during sunlight hours.

Previous analysis by AEMO has already suggested that major increases in utility-scale solar generation in particular will likely drive significant increases in the required amount of regulation FCAS. The figure below draws from this analysis. Note that this projection is only approximate due to data and forecast accuracy. It also assumes no significant systematic improvement in solar farm behaviour or forecasting capabilities. It is based on projected movements on the 5-min scale, rather than shorter time scales, but illustrates the effect of increased variability on regulation services:

[14] See AEMO's advice to the AEMC as part of the Stage 1 of the Review of the Frequency Operating Standard: https://www.aemc.gov.au/sites/default/files/content/9a79771b-9794-45da-8493-e22842d45275/AEMO-Advice-%E2%80%93-Stage-one.pdf



As decreasing availability of frequency responsiveness is coinciding with increasing demand for frequency responsiveness, it is reasonable to conclude that new providers of frequency response will be needed. For example, with a large amount of solar generation available during the middle of the day, it seems obvious to try and access frequency control from these solar generators. Provided the necessary control systems are fitted (the proposed new Generator Technical Performance Standards[15] seek to ensure new generators have such capabilities), there is no technical reason why a solar generator cannot provide primary and/or secondary frequency control (or alternatively, manage their output so as to reduce the need for FCAS). However, in order to actually provide upwards headroom, a solar (or wind) generator must be pre-curtailed. Generators would need to be incentivised or compensated for operating in this manner. AEMO has significant concerns about the ability of the current FCAS markets to deliver this. For example, this would at least require that FCAS prices exceed the potential revenue from energy sales and renewable energy certificates (or similar). Even this may not be sufficient to encourage pre-curtailment if generation from such facilities is largely contracted under power purchase arrangements, as is commonly the case at present. These contractual arrangements usually span many years. An alternative may be that such generators incorporate appropriately sized and configured storage in order to provide headroom and frequency services, but once again, the financial incentives available would need to justify such an investment.

These are complex issues, and in order to explore them fully, detailed dispatch and economic/financial modelling will likely be required. Consideration must also be given to the other related market changes such as inertia and system strength. AEMO recommends the AEMC and AEMO continue to work together on exploring the future outlook for frequency control requirements and availability to inform the FCFR and the broader ongoing work of ensuring the NEM's system security services are appropriate, efficient and forward-looking.

[15] http://www.aemc.gov.au/Rule-Changes/Generator-technical-performance-standards