Ref: EPR0059

24 April 2018

Attention: Ms Claire Richards
AEMC
ELECTRONICALLY SUBMITTED

Dear Ms Richards

Frequency Control Frameworks Review – Draft Report

We welcome the opportunity to respond to the Draft Report of the Frequency Control Review.

CS Energy concurs with the AEMC's description of good frequency control. The system should have controlled changes in frequency and there should not be undamped oscillations in frequency.

Ideally there should be a mix of proportional and integral action, with an aim to avoid fast proportional oscillations that may be caused by too much primary response and to avoid slow integral oscillations that may be caused by integral overshoot from too much secondary response. This review should not simply focus on restoring primary, proportional response and removing secondary control.

In our view it would be sensible to implement Recommendations 1 and 2 ('Option F') as transitional measures whilst prototyping a superior frequency control framework, such as a 'deviations' concept. Additionally, we consider Recommendation 1 should be amended to improve the netting arrangements in the Causer Pays procedure.

Further, we recommend the AEMC challenge further the premise of whether it will be efficient, with a reduction in large synchronous plant; a change in system characteristics (with reductions in synchronous motors); more switching technology and profusion of small generating units, for the NEM to centrally control and schedule frequency response as it does today. CS Energy developed a proposal with Intelligent Energy Systems ("IES"), to at least attempt to understand how the electricity market could rely less on central control.

In our submission to the Stage 1 review of the Frequency Operating Standard, CS Energy stated the FCAS arrangements are far from ideal and discussed the potential for frequency control to be decentralised. The market would be able to determine the appropriate quantity (and subsequent quality of frequency) depending on the cost. Additionally, we stated that market signals could also optimise the mix of inertia (Rate of

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Change of Frequency "RoCoF"), and fast and slow frequency services, especially if these services are integrated into energy settlement amounts.

We are therefore thankful the AEMC has put forward the CS Energy / IES proposals in Chapter 8 of the Draft Report when discussing future options.

Regarding Chapter 8, CS Energy found the 'spectrum' of potential frameworks to be helpful.

As previously submitted, the need for central control is a premise that should be tested. In our submission to the System Security Review, CS Energy proposed that it sensible to integrate security services into the price auction as far as possible and to reduce the dependence on centralised specification, dispatch and intervention. We recommend the AEMC in its final report attempt to answer the question of whether it is more efficient to centrally control, or decentralise, security services such as frequency.

To this end we consider there to be merit investigating further the 'deviation' proposal against one that aims to improve the current arrangements, yet retain the premise of centralised specification and control. We consider the "Revised contingency FCAS market" developed by *SW Advisory and DIgSILENT Pacific* to be a rather elegant solution that could be considered against a style deviation proposal.

There follows an attachment to this letter which:

1) responds to the series of recommendations for the Frequency Control Ancillary Services ("FCAS") markets made in the Draft Report; and
2) provides additional information regarding Chapter 5 to clarify some points made by the AEMC.

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Draft recommendation 1: Causer pays procedure

Recommendation 1 states:

That AEMO investigate whether:

i. *the average period used for calculation of contribution factors could be aligned with the period over which the costs are incurred, preferably on a 5-min basis*
ii. *the ten-business day notice period between publishing and applying contribution factors is appropriate or could be removed.*

Whilst reducing the averaging period and removing the time lag are vast improvements from the current approach, from a theoretical perspective it isn't sensible to use any averaging period (even as short as five minutes).

This is especially the case when trying to develop incentives at the margin for a market that:

i. we know changes faster than 5 minutes, (we will come back to this in discussing recommendation 2, Option F); and
ii. which we can measure at 4 seconds today and, with suitable metering, will be able to measure in a superior manner in the future.

Without going into detail, the key point is that average does not equal marginal and therefore does not reflect marginal cost, cannot be reflected in efficient marginal pricing and cannot encourage efficient marginal decision making during the average period. It will therefore lead to frequency being either too high or too low (too loose or too tight) within the averaging period.

However, if the incentive is calculated on a 4 second basis, controls engineers can tune governor control systems to optimise the unit response to a 4 second incentive. The tuning will not be as precise if the incentive is dulled to 5-minutes.

Additionally, the 'netting' arrangements in the Causer Pays procedure should be amended to improve marginal cost incentives.

After AEMO commenced its review of Causer Pays in October 2016, CS Energy submitted to AEMO in 2017 a proposal to change the netting arrangements. AEMO was helpful in discussing these arrangements, assisting with data and investigating the treatment of Load Forecast Error and metered non-scheduled elements. The analysis of this proposal was confused by problems relating to the NSW load forecast error and Smithfield Energy Park, explained later in this submission. Whilst AEMO did not go so far as to adopt these recommendations in its recent Draft Determination, AEMO did state the proposal appears to have merit.

The netting arrangements proposed by CS Energy aimed to improve the cost allocation, through the following changes:

1) Load Forecast Error – netted across all regions, not calculated individually for each.

This is consistent with the effect of the regional five-minute forecast resulting in a need for regulating FCAS services – it does not matter whether one region is in error if it is offset by another.

2) Metered non-scheduled loads should simply be treated as 'metered' and netted so.

   These loads presently are allocated too great a share of costs – not only are they measured against a trajectory, just as scheduled generators and loads, but they are also allocated a share of the non-metered error. There is no clear justification for this in the procedure.

3) Removal of the distinction between metered non-scheduled and scheduled, allowing netting across all metered elements.

   These 4 sec metered elements all have trajectories, (be it scheduled or implicit (flat)), such that everything with a trajectory should be netted, as it is the 'net' that affects the frequency error and need for regulation services.

4) All elements with a trajectory against which they have been measured should be netted, with this performed at a system level, to give the split between metered and residual before allocating per participant.

   The current approach only nets per participant, yet it is the net of all Scada metered loads and generators, be they scheduled or not, that affects the frequency error and need for regulation services.

5) There should be no combination of performance factors between low and high frequency.

   Currently the final Market Participant Factor is calculated by summing the performance for low and high frequency and using this in proportion to the other measures, which is then multiplied by the cost of both Regulating Raise and Lower.
   This leads to poor performance in low frequency possibly incurring a cost in high frequency regulation services and vice versa. Given the two markets have differing cost characteristics, this is an inefficient allocation of cost.

CS Energy considers these changes to the netting arrangements are as important as shortening the averaging period and removing the delay. In short, if the netting arrangements are wrong, then there is little point in improving the other elements as we are simply sharpening the timeframe for the wrong allocation. We request the AEMC recommend AEMO review the netting arrangements concurrently with the amendments in Recommendation 1.

That AEMO provide greater clarity of the causer pays procedure and the specific variable that generator performance is measured against.

Ideally all participants should be able to understand the Causer Pays calculations and "mimic" the allocation in real time, using their own control data to calculate their costs. The specific variable (or calculation) that generator performance is measured against must be known, or should at the very minimum be able to be calculated by a sophisticated market participant, in real time.

We have stated that the objective should be a mix of proportional and integral action and as such the measure may not simply be a function of local or system frequency, but be some algorithm using a mix of frequency, cumulative frequency error, gain and some timing constants.

The units should be measured against what they are supposed to achieve: as a starting assumption a unit providing integral control should be measured against the need for integral response (presently the Frequency Indicator) and units providing proportional control should be measured against local frequency. For units not designated to provide a specific service, the measure should be aligned with the objective (which may be a mix of primary and secondary, proportional and integral response). We discuss this further when considering Option F in the AEMC's Recommendation 2.

Draft recommendation 2: Provision of a primary regulating response

Recommendation 2 states:

That the providers of a primary regulating response should be remunerated for the costs of providing the service, in particular where the opportunity costs of maintaining the capacity to provide the service (e.g. maintaining headroom to be able to increase output) are likely to be high.

CS Energy considers consumers would be better off if producers are paid for proportional control. On one side of the ledger, consumers would incur the costs of AEMO paying producers to provide proportional response, yet on the other will be rewarded for improvements in the quality of frequency control. Importantly consumers, (if AEMO gets the quantity correct), will only pay for quantity of proportional governor response that they require, thus leading to an efficient level of response, improving productivity.

If producers are simply required to provide proportional response, AEMO will face no cost and can therefore aim to improve frequency performance on consumers' behalf without expense. This may lead to frequency control that is, at first, unproductively good and may impose costs elsewhere in the process of generating electricity. The question is whether this is sustainable as producers, who by not being recompensed for the service, may fail to ensure quality and would need to be forced to do so.

It is for these reasons it is in consumers' interest that providers of a primary regulating response should be remunerated for the costs of providing the service. CS Energy therefore agrees with Recommendation 2.

The implementation of one of the following options is likely to build on the existing market frameworks and support improved frequency control during normal operation:

i. provision of a primary regulating response through the existing regulating FCAS markets
ii. changes to the causer pays arrangements to facilitate the provision of incentive payments for primary frequency response during normal operation.

Further work is required to investigate and describe the potential arrangements for the implementation of these options, and the associated costs and benefits of these arrangements.

The **option 'A'** in the Draft report is an integrated Primary Frequency Control and AGC Regulation Service. We call this **'REG-PFC'**, in that it uses the Automatic Generation Control ('AGC') regulation service within a tight dead-band of frequency and then uses proportional governor control (or as otherwise provided by a frequency controller) outside this dead-band, yet still inside the Normal Operating Frequency Band ('NOFB'). This is as opposed to AGC Regulation or ('AGC-REG') that we have today.

CS Energy has some concerns as to the effectiveness of this proposal. These concerns are largely technical and described as follows:

Double dipping of steam pressure?

CS Energy is concerned that blending proportional governor control with AGC-REG may result in steam pressure being unavailable for proportional response when a contingency occurs. This may result in a requirement to reduce the contingency FCAS procured from units providing this service, or it may require more contingency FCAS to be enabled.

It is CS Energy's opinion, and supported by empirical evidence, (such as that put forward by CS Energy in response to Stage 1 of the Frequency Operating Standard Review), that there are already problems with units trying to ramp, provide AGC-REG and then respond to a contingency. At times unit response is of poor quality. This is especially the case with AGC-REG units on the mainland, either when concurrently enabled with Tasmanian units (which are pulsed less than their Mainland competitors) or at times of increasing Area Control Error, because the enablement amount is heavily utilised by the AGC system's 4-sec pulses.

A unit on a sustained load increase ramp will often suffer loss of a significant portion of its throttle margin (stored steam pressure energy). However, if the unit controls are tuned correctly, short-term steam pressure disturbances due to AGC-Reg (or Primary Frequency Control ('PFC') for that matter) for small frequency disturbances within the NOFB should not be significantly different from normal disturbances, (due to soot-blowing for example) and the bulk of the throttle margin should be maintained.

Theoretically, the maximum AGC-Reg demand in a 5-minute period would compromise throttle margin the same as a sustained load ramp, but AGC-Reg *should* rarely call on all the available ramp capability in one direction within 5 minutes as otherwise the secondary control system would not be able to control frequency. We note that empirical evidence suggests units enabled for AGC-REG on the Mainland, such as Gladstone are routinely sent 4 sec pulses for the full AGC-Reg capability. This is due to insufficient quantities of ACG-REG being purchased to control the error. As such, with the current enablement amounts, units on ACG-REG may have less throttle margin than is required for contingency services.

However, in the event of a large frequency disturbance, the maximum fast proportional response available from a unit supplying proportional response with no dead-band is the same as if it had a dead-band and supplied it all as contingency response; the response has just commenced earlier, inside the NOFB. There is no magic pudding; you can't supply PFC and still have the same contingency capability outside the dead-band. It should however be noted that the earlier response is more valuable for system security.

Difficulties setting dead-bands for REG-PFC and Contingency FCAS

The REG-PFC would require units to change the settings on the dead-bands to provide the service. These settings may be integrated into operator's control systems, but are unlikely to be integrated into the trader's bidding systems. This means the units providing REG-PFC would likely provide the PFC element of the service irrespective of whether they are enabled for the service.

Given most providers of AGC-REG today are also providers of Contingency FCAS, this has a similar effect to, and same drawbacks as, Option B in simply tightening the NOFB to the edge of the band inside which REG-PFC providers are supposed to provide AGC, integral control.

This may result in the unintended consequence of providers withdrawing availability from this REG-PFC service, at least on a few units, as they will not want to provide more service than they are being paid for. For instance, units enabled at Gladstone Power Station are routinely enabled for small quantities (7MW or less) of ACG-REG and know that it is only these increments of ACG-REG that will be called upon by the computer control system, AGC. If these units were set up with a narrow dead-band for REG-PFC, yet were not enabled, then this would result in provision of service that is are not paid for in the proportion of the NOFB that is allocated to PFC.

Gladstone units are regularly enabled for less LowerReg than RaiseReg. This is because these markets have fundamentally different cost characteristics depending on energy prices at the time, available headroom, ramping, etc. and tend to have different demand, noting that RaiseReg results in higher AGC signals than LowerReg. It should be noted there are frequently different providers and always different prices for these services. It is possible that some providers may concentrate on REG-PFC in one direction only and dead-bands may be set a manner that is not symmetrical.

Hybrid provision of proportional and integral control

If for instance the AGC element of the REG-PFC service is narrow, this leaves little time for units to provide slower, integral control. It appears unnecessary to reserve frequency bands for the integral and proportional control in this way.

CS Energy considers that it is superior for a mix of proportional and integral to be provided within the NOFB, and not be reserved to separate frequency bands. Units should also avoid providing the proportional and integral services at the same time. CS Energy found, (see evidence provided to the Reliability Panel's Review of Frequency Operating Standard), that units with narrower dead-band settings (i.e. providing proportional control) do not respond well to AGC signals when providing integral control. The advice provided by AEMO largely concludes the same, in that proportional response within the NOFB assists in reducing the error that the integral response needs to cope with. The proposal is not clear as to how individual units can provide the integral response, especially if there is a frequency offset to correct time error.

In summary, CS Energy does not support Option A.

For reasons similar to those explained by the AEMC in the Draft Report and some of the reasons above, CS Energy does not support Options B to E.

Given CS Energy does not support the other options, it is time to turn to **option 'F'** in the Draft Report. This option requires changes to the causer pays arrangements to facilitate the provision of *additional* incentive payments for primary frequency response during normal operation Regulation Service.

Additional payment to avoiding Regulation FCAS costs

It is important that the incentive payments for proportional response under the causer pays method are additional rather than simply a mechanism for avoiding payments under Causer Pays, as otherwise this proposal will not work. (This isn't clear from reading the document, because the price to be paid/pay isn't discussed. Bar the proposes changes to averaging, temporal delays and substitution of the ACG Frequency Indicator to local frequency, it will be like the Causer Pays calculation we have today). This is because suppliers will be incentivised to avoid providing proportional response and focus on integral, secondary control: if they provide proportional control their earnings would be reduced from AEMO's subsequent reduction in the amount of integral, secondary Regulation that it procures.

We have read this in conjunction with the changes to Causer Pays as explained in Recommendation 1. As such, if we assume the incentive is priced and allocated on a 5-minute basis this may suffer from the problem highlighted in our response to recommendation 1, which is also the fundamental problem the with NEM's dispatch of AGC-REG, through the "specify" and "enable" approach.

It isn't ideal that the quantity (Q) of response is set in advance, the price (P) is calculated at the same time and 'fixed' over the five minutes. Q and P are too much/too high or too little/too low over the five-minute period as participants deviate from trajectories to deal with errors in forecast, load deviations or generator deviations. This error will inhibit efficient marginal decision making within the dispatch interval's five minutes and will therefore, on a first principles basis, lead to frequency being either too high or too low (too loose or too tight) within the averaging period.

Notwithstanding the previous statement, reducing the averaging period to 5 minutes, (rather than 28 days, with a lag of 10 days), and paying for positive measures under Causer Pays, will be a vast improvement on the status quo. However much will rest on how the 'price' is calculated to pay for proportional response and how the 4 second metrics are calculated. For example, if the price is calculated every 5-minutes and the 4-sec data averaged over the 5-minute period then the incentive to provide response will be dulled.

It appears to us that the price in Option F is to be set for each 5-minutes at the start of the Dispatch Interval. This may be acceptable as a transitionary measure, before some other method of frequency control, such as a 'deviations' concept is implemented with a superior cost function based on shorter term costs (inertia 4 sec and sub 4 sec).

As a transitionary measure CS Energy wouldn't support setting the price using the price of Regulation FCAS, given the likelihood of Primary Frequency Control to lessen the price of Regulation FCAS. This would be self-defeating for providers.

A better solution may be calculating the implied value of the MW headroom (and foot-room for high frequency) using the pool price less the cost of fuel ABS(11.5*NEWC6000*(USD/AUD)) with the Newcastle index expressed as a $USD/GJ value, flooring this at the sum of the 6 and 60 contingency services to give a dollar sum of the cost of 'capacity' for the 5-minute period. This cost can then be allocated to, and from, units based on how their 4-sec deviations from their required trajectories either provided, or caused a need for this headroom. When applying this cost, amplifying by some factor, possibly matching to the 'gain' settings used in the 4 second performance measure.

The incentive should be based on the objective

When discussing the options for setting prices in the proposals put forward by IES to the System Security Review, the idea was that the 4 second incentive could be something developed through the prototyping arrangements, where the cost function could be amended and "dialled up or down" to encourage good frequency control. The potential cost of providing control, including fuel, ramping, wear and tear, were inputs and estimated in the cost function. These costs are simply estimates designed to mimic the cost of provision and solicit an optimised response over time. With experience we could expect improvements to the algorithm dialling up or down the costs to reflect actual costs: that is participants wouldn't respond to certain elements of the price, if the prices were lower than their costs of providing response.

Accordingly, whilst we agree with the idea of a 'cost function' that would be published to participants as explained in 8.4.4 of the report, we are unsure about the validity of figure 8.4 in the Draft Report, where the cost is represented as zero upon 50Hz and increasing markedly either side of 50Hz. This cost function in 8.4.4 suggests suppliers should only provide response in a proportional manner, which is probably simplistic, given the need for both proportional and integral control and a mix of inertia, fast and delayed responses. It also suggests there should be no need for cashflows, or very limited cashflows to occur when frequency is close to 50Hz, even though there may be quite significant MW deviations by some parties which are compensated by others. This is worth investigating further.

We consider there should be a mix of proportional and integral action, with an aim to avoid fast proportional oscillations that may be caused by too much primary response and to avoid slow integral oscillations that may be caused by integral overshoot from too much secondary response. Because of this objective it is likely that the algorithm will not simply be a function of local or system frequency, but be some optimum mix of frequency, cumulative frequency error, gain and some timing constants.

In summary, CS Energy considers Option 'F', where the Causer Pays arrangements facilitate the provision of incentive payments for primary frequency response to be far superior to Option 'A'.

In our view it would be sensible to implement Recommendations 1 and 2 ('Option F') as transitional measures whilst prototyping a superior frequency control framework, such as the 'deviations' concept, where the goal is to properly price <u>frequency control within the 5 minutes</u>. Such low-cost prototyping could be completed concurrently with a determination on whether the premise of central specification and control of security services, such as frequency, is in the consumers' interest.

Comments on Chapter 5

Unfounded conjecture regarding residual amount in Causer Pays (Figure 5.3)

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 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 and reduced the residual to a level lower than it should have been. Because of this, Figure 5.3 of the Draft Report is misleading and the discussion preceding the figure is unfounded.

Confusion regarding where costs are incurred for Regulating FCAS (Figure 5.2)

Figure 5.2, identifying which regions 'contributed' to the increase in Regulating FCAS costs is misleading. Figure 5.2 appears to show where the FCAS has been sourced, not the region(s) in which it was required. The Regulating FCAS market is usually a global market, or both Mainland and Tasmania. In those instances, units in one region will regulate the frequency across multiple regions. There may be a few instances of local requirements (excluding Tasmania), yet these are rare, bar the more recent South Australian local requirements. Additionally, if there is surplus of Regulating FCAS, or there is a local requirement for delayed 5-minute response, Regulating FCAS can substitute for delayed contingency FCAS - these payments may also be shown in figure 5.2.

As discussed in CS Energy's submission to the Review of Frequency Operating Standard, it should be remembered that FCAS nearly always traded at a discount to energy, with roughly being a factor of 8 to 10, (unless, upon occasion, there are stringent local requirements upon separation). So although it may be true the FCAS costs may have increased at a greater multiple than energy prices in recent years, this is simply a function of the discount to energy reducing. One would not expect FCAS prices to continue to rise further, above the cost of energy, because the energy market and FCAS markets are co-optimised, by NEMDE optimising the cost of providing FCAS headroom and procuring enough energy to meet demand.

Importantly FCAS prices, specifically the sum of Raise contingency, or Raise Regulation have both trended up towards to the opportunity cost of headroom. Additionally, Lower Regulation prices have trended up based on opportunity costs of lost profits in responding to AGC lower pulses.